BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Tri-State	)	Order No. 202-25-14
Generation and Transmission	)	
Association, Platte River Power	)	
Authority, Salt River Project,	)	
PacifiCorp, and Xcel Energy	)	

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-46:
R Street Institute Commentary: DOE "Zombies" Are Eating
Competitive Power Markets

REAL SOLUTIONS

Low-Energy Fridays: DOE "Zombies" Are Eating Competitive Power Markets

BY MICHAEL GIBERSON

ISSUES: ELECTRICITY POLICY, ENERGY AND ENVIRONMENT

NOV 13, 2025

This past May, the U.S. Department of Energy (DOE) used emergency authority to stop two scheduled power plant retirements. As we explained in July, these emergency orders are not a good way to boost grid reliability. That's not the only problem, though—the DOE's emergency orders also threaten to undermine competition in regional power markets.

The case invoked Section 202(c) of the Federal Power Act, which limits most orders to just 90 days. The DOE used this law to block the coal-fired J.H. Campbell Power Plant in Michigan and two units at the gas- and oil-fired Eddystone Generation Station in Pennsylvania from retiring. When those 90-day orders expired in August, the DOE issued new orders to keep the plants online. When these orders expire later in November, the DOE is expected to order the plants to stay online for *another* 90 days. Both currently operate with a safety net: If they lose money, the law makes area consumers cover those losses. And with losses covered no matter what, the plants have little reason to run efficiently. The result isn't grid reliability—it's creeping zombification of the market.

Markets require profits *and* losses to steer investment where it's needed (and away from where it's not). When a unit can't cover its costs at market prices, it should retire. When older, inefficient plants exit, space opens on the grid and in the market for better resources to jump in. Prices may initially rise, but consumers benefit in the end as competition grinds down average costs. Serial "emergency" orders break the economic feedback loop and undermine competitive forces.

The DOE's decision to keep two fossil-fueled power plants running raised speculation that the administration would block any fossil-fueled plant from retirement. However, a New Hampshire coal unit retired in October without federal intervention. That's good, because a plant that doesn't contribute to reliability and energy supplies at a competitive price *should* retire. But the lack of clear policy heightens uncertainty.

The economic damage shows up in three places:

- **Crowding out.** When zombie power plants are ordered to stay in the market, customers are stuck with the bill from any losses. Market revenues that would support efficient resources get skimmed by units the market has already rejected. The effect is subtle but important: Energy market prices flatten, clean and firm resources see less upside in tight hours, and generation turnover slows.

- **Planning.** Reliability planning depends on credible schedules—retirements that can be believed, new power plants that can be counted, and rules that don't change unnecessarily. A plant yo-yoing between "retired," "ordered to run," and "maybe extended" in 90-day increments can't fit into long-run reliability plans.

- **Policy-driven uncertainty.** States and stakeholders are suing the DOE over the emergency orders because the law is being employed in a manner different from what Congress intended. The DOE has not articulated a clear policy for how they will use their authority in the future, which leaves plant owners and potential investors in the dark.

Emergency orders do have their place. If a hurricane hits, fuel freezes, or a wildfire takes out a major power line, use 202(c) for the days or weeks necessary and then stand down. Utilities regularly ask for these emergency orders when they need them. The difference with zombie plant orders is that neither the plant owners nor the grid operators responsible for reliability in their regions requested them.

Nothing in this discussion denies reality—demand for electricity is rising, interconnection queues are clogged, and grid operators face tough winters and hot summers. The way forward is in policies that make better use of the existing grid, drive economical additions to transmission infrastructure, and let market forces drive power plant entry *and* exit. Competitive power markets are not responsible for rising electricity rates; in fact, a recent study pointed to increased spending on transmission and distribution wires as key factors in driving up customer rates.

Should the DOE continue to undermine market competition, consumers may get hit with the double-whammy of rising energy costs and rising infrastructure spending. Zombification of the electricity industry is no way to support a reliable, efficient power system.

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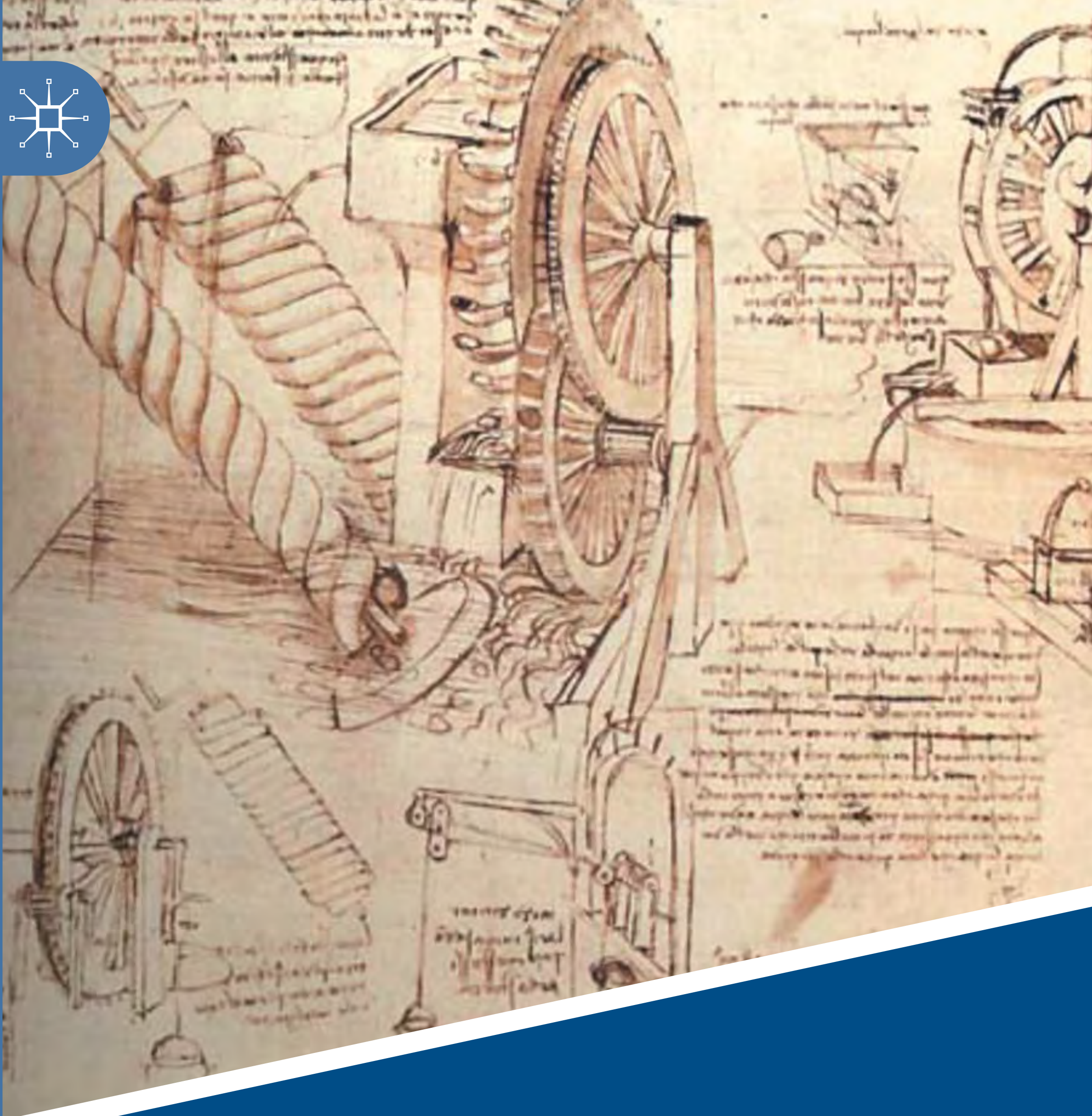
Exhibit 1-47:
Palgrave Handbook



The Palgrave Handbook of International Energy Economics

Edited by Manfred Hafner · Giacomo Luciani

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rotating standby state through the advanced control system, and the gas turbine is quickly started with load, and the power is immediately transmitted to the power grid.

3.4 Location

Coal power generation location is more restrictive compared to other technologies because coal is a solid and its transport cost is high, while its combustion efficiency is lower than for other technologies. Usually coal plants are located near coal mines and the choice of different means of transport will affect the location of the plant area as well as the size and form of the required land plot, especially for a large power plant. The transportation mode should allow for large volume, low freight, high speed, and flexibility, which will make the location of coal plant all the more difficult.

On the contrary, oil is easy to transport with multiple transportation options including by pipeline and by ship; therefore, oil-fired plants are usually located in coastal areas. A gas-fired power plant is characterized by little land occupation and is very suitable for countries and areas with dense population and scarce land resources. Compared with coal-fired power plants, gas power generation equipment is more compact and does not occupy a large area. Besides, it consumes one-third of the water needed for a coal-fired power plant.

3.5 Expected Service Life

Thermal power plants are designed for an economic lifetime of 30 to 40 years, but some plants have been also used beyond their design life in certain areas. The critical components are the boiler and the turbine. The operation of thermal power generation is faced with both tangible and intangible aging processes. Tangible or physical aging refers to the equipment operating under high pressure and temperature, and bearing mechanical stress, resulting in physical and chemical changes, such as wear, creep, corrosion, and so on, gradually making the equipment unable to continue operating safely under the required design parameters. Invisible aging refers to technological progress. The advent of more efficient or less labor-intensive production equipment means that older equipment will operate under less and less economic conditions. The physical aging of some equipment (such as condenser copper pipes, heater pipes, boiler heating surface pipes, turbine blades, furnace walls, etc.) can be removed during overhaul. However, it is often the aging of these important equipment components that determines the technical and consequently economic lifetime of thermal power plants. Operating experience shows that the service life of equipment operating under 450 °C is between 40 and 50 years. For equipment operating at temperatures above 450 °C, the operating hours could even be reduced to 100,000 hours.

Both gas and steam turbines are devices that drive the rotor to rotate at high speed through high-pressure gas with high temperature and humidity.

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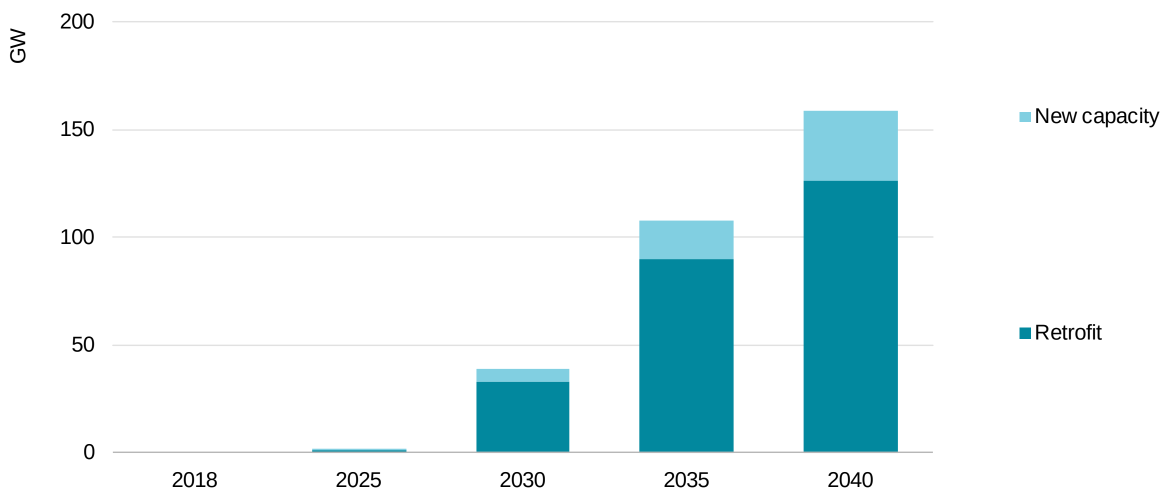
Exhibit 1-48:
IEA Report

The role of CCUS in low-carbon power systems

Without carbon capture, meeting climate goals would ultimately mean almost eliminating the use of fossil fuels for power.

In the Sustainable Development Scenario, 120 GW of existing coal-fired capacity is retrofitted with carbon capture by 2040, accounting for some 80% of the coal plants equipped with these technologies. More than 110 GW of these retrofits are in China, representing a capital investment of around USD 160 billion. A further 10 GW are in the United States. Without carbon capture available at scale in power, coal-fired power generation, and eventually also gas-fired generation, would need to be virtually eliminated to meet long-term climate goals, with significant early retirements and potential stranding of assets.

Figure 4 Coal-fired power plants equipped with carbon capture in the Sustainable Development Scenario



Source: IEA (2019), World Energy Outlook 2019.

Over 750 GW of existing coal plants reduce operations to cut emissions in this Scenario, limiting electricity production but still providing system adequacy and flexibility. About one-quarter of the existing fleet would be retired before reaching the typical 50-year lifespan. Shutdowns and reduced operating hours are likely to lead to balance sheet write-downs for some owners of existing facilities. Coal plant retirements also imply greater investment in other low-carbon sources of electricity and associated network infrastructure.

Carbon capture retrofits also play an important role for the gas-fired power plant fleet, which currently has an average age of only around 19 years. In the SDS 155 GW of natural gas-fired power plants are equipped with carbon capture, utilisation and

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-25-14

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Filed January 28, 2026

Exhibit 1-49:
Tri-State Revised 2020 ERP Assessment of Existing Resources

Electric Resource Plan

Assessment of Existing Resources

REVISED

June 1, 2020 Informational Filing

for

Tri-State Generation and Transmission Association, Inc.

Submitted to:

Colorado Public Utilities Commission

August 3, 2020

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Background

Pursuant to Commission Decision No. C20-0304, in Proceeding No. 19R-0408E and Rule 3605 (a)(i) of the Colorado Public Utilities Commission's Rules Regulating Electric Utilities, Tri-State Generation and Transmission Association, Inc. (Tri-State) submits the following assessment of existing resources pursuant to paragraph 3605 (c) to the Public Utilities Commission of Colorado (Commission).

Summary

Tri-State is a wholesale cooperative electric generation and transmission association consisting of 43 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 between 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 Basin Electric Power Cooperative (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 power purchase agreements.

Figure 1 below illustrates the geographic diversity of Tri-State's load and resources along with Tri-State Merchant[1] 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)
- Public Service of Colorado (PSCo)
- Platte River Power Authority
- Western Area Power Administration (WAPA) Rocky Mountain Region Loveland Area Projects
- Black Hills Energy Colorado
- PacifiCorp

Additionally, Tri-State Merchant is a point-to-point transmission customer of many Transmission Providers in the Western Interconnection. Tri-State Merchant uses these network and point-to-point transmission rights within Western Electricity Coordinating Council (WECC) TOT 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.

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

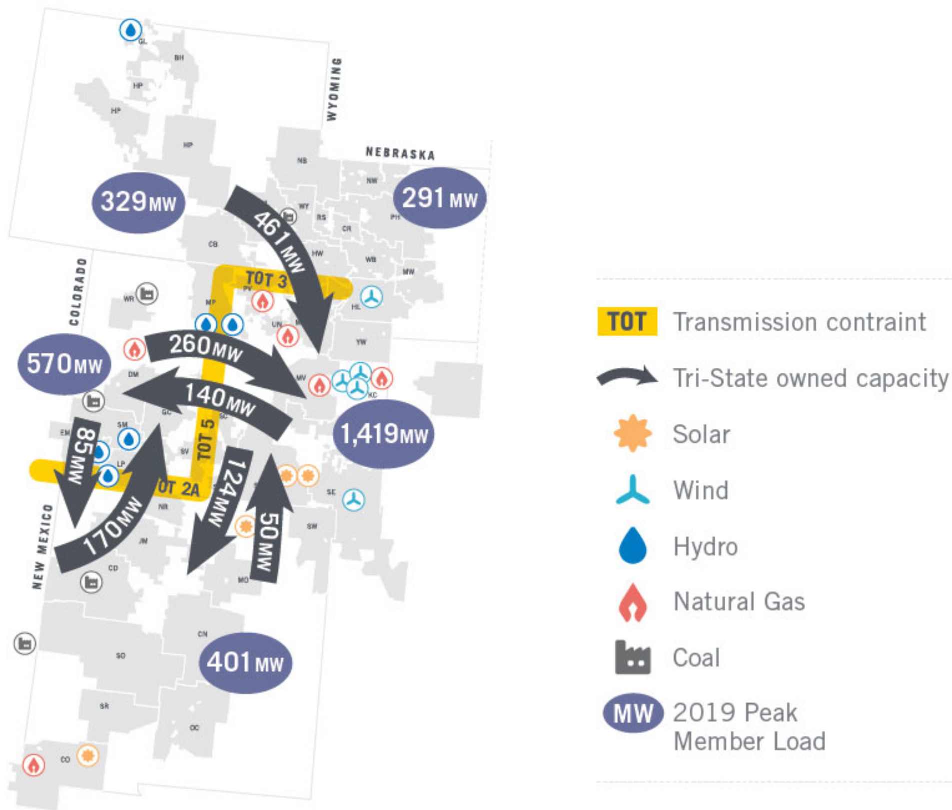


Figure 1 – Tri-State System Map

The following assessment describes existing resources both operational and contracted for at the time of this filing with appropriate detail as prescribed in 3605 (c).

Assessment of Existing Resources

1. Owned & Leased Resources

Assessment Approach

The following is a description of Tri-State-owned and leased resources in terms of unit characteristics, emission rates and revenue requirements. 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:

- Escalante is excluded, as it will be retired by December 31, 2020.
- Craig 1's useful life is identified as its announced retirement date. Original useful life was in the 2030s.

- 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 Resource Acquisition Period (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 our oil units are used for reliability events not economic dispatch and planning.
- Emissions rates are based on 2018 actuals data as provided by Tri-State Environmental; data will be refreshed as 2019 actuals are finalized and updated in the December 1, 2020 ERP filing.
- 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 are an average of annual expenses over the Resource Planning Period of 2021 to 2040 for the life of each resource as determined by useful life or planned retirement date.
- Costs associated with the use of emissions control systems are not separately forecasted, but are instead included in overall operating and maintenance costs.
- Although not a unit level revenue requirement, Social Cost of Carbon 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 Social Cost of Carbon is calculated as the resource carbon emission rate of each unit in tons per MWh times $46.00/ton social cost of carbon.
- 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))

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)[2], 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[3]. Tri-State's total share of Craig Station is 648 MW. In 2016, Tri-State announced an agreement with regulators and environmental groups to

[2] Yampa Project includes Craig 1 and Craig 2 and related common facilities.
[3] Yampa Project participants include Tri-State, Platte River Power Authority, PacifiCorp, Salt River Project and Public Service Company of Colorado.

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, 1,710 MW coal-fired electric generating facility located near Wheatland, Wyoming. As a participant in the Missouri Basin Power Project[4], Tri-State has a 27.1% interest (464 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.

Unit Characteristics

	Craig 1	Craig 2	Craig 3	LRS 2	LRS 3	SPV3
Average Heat Rate *(btu/kWh)*	10,316	10,219	10,135	9,926	10,286	9,945
Marginal Heat Rate *(btu/kWh)*	10,464	10,509	10,491	9,878	10,206	10,168
Quick Start Capable *(Yes/No)*	No	No	No	No	No	No
Minimum Operating Level *(MW)*	31	31	130	94	94	109
Useful Life	12/31/2025	12/31/2039	12/31/2044	12/31/2041	12/31/2042	12/31/2066

Emission Rates

lbs. per MWH	CO_2	SO_2	NOx	PM	HG
Craig 1	2319	0.378	2.771	0.042	0.00001700
Craig 2	2350	0.345	0.672	0.047	0.00001400
Craig 3	2090	1.308	2.248	0.061	0.00007800
LRS 2	2203	1.101	2.331	0.095	0.00004110
LRS 3	2407	1.823	2.410	0.177	0.00004680
SPV3	2139	0.838	0.787	0.031	0.00001600

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

Revenue Requirements

	Fixed O&M Annual *($000s)*	**Variable O&M** *($/MWH)*	**CapEx Costs Annual** *($000s)*	**Social Cost of Carbon** *($/MWh)*	**Integration & Cycling Costs** *($/MWh)*	**Fuel Curve** *(See Figure 2)*
Craig 1	[redacted]		~$500	$53.34	$0.129	CRG (Inc)

[4] 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.

Craig 2	[redacted]	~$500	$54.05	$0.131	CRG (Inc)
Craig 3	[redacted]	~$3,000	$48.07	$0.124	CRG (Inc)
LRS 2	[redacted]	~$1,500	$50.67	$0.111	LRSG
LRS 3	[redacted]	~$1,500	$55.36	$0.108	LRSG

Tri-State forward coal prices change annually. Figure 2 below shows the current coal forward curve inclusive of inflation. CRG (All-In), LRSG and SPV3 values are all inclusive costs of fuel. CRG (Inc) is the Craig coal cost as an incremental value.

[redacted]

Figure 2 – Coal Price Curve

Gas & Oil-Fueled Generation Resources

Below capacity ratings are composite annual MW rating.

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

<u>Rifle Generating Station:</u> 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.

<u>Limon Generating Station:</u> 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.

<u>Knutson Generating Station:</u> 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.

Unit Characteristics

	JM Shafer	Rifle	Limon	Knutson	Pyramid	Burlington
Summer Capacity *(MW)*	272	72	67	67	40	48
Winter Capacity *(MW)*	272	84	74	74	40	60
Fuel type	NG	NG	NG/FO	NG/FO	NG/FO	FO
Average Heat Rate *(btu/kWh)*	9,322	10,321	11,449	11,449	9,742	14,000
Marginal Heat Rate *(btu/kWh)*	9,282	10,965	10,852	10,835	9,985	-[5]
Quick Start Capable *(Yes/No)*	No	No	Yes	No	Yes	Yes
Minimum Operating Level *(MW)*	41	22	40	40	25	25
Useful Life	12/31/2047	12/31/2028	12/31/2048	12/31/2048	12/31/2049	12/31/2037

NG = Natural Gas; FO = Fuel Oil

Emission Rates

lbs. per MWH	CO_2	SO_2	NOx	PM	HG
JM Shafer	981	0.008	0.747	0.080	n/a
Rifle	1206	0.001	2.611	0.239	n/a
Limon	1495	0.008	0.378	0.062	n/a
Knutson	1502	0.009	0.341	0.124	n/a
Pyramid	1240	0.012	1.223	0.070	n/a
Burlington	2149	0.194	12.383	0.158	n/a

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

Revenue Requirements

	Fixed O&M Annual *($000s)*	**Variable O&M** *($/MWH)*	**CapEx Costs Annual** *($000s)*	**Social Cost of Carbon** *($/MWh)*	**Fuel Curve** *(See Figure 3)*
JM Shafer	[redacted]	[redacted]	~$1,500	$22.56	CIG
Rifle	[redacted]	[redacted]	~$200	$27.74	CIG
Limon	[redacted]	[redacted]	~$275	$34.39	CIG
Knutson	[redacted]	[redacted]	~$400	$34.55	CIG

[5] Burlington did not dispatch over the RAP

Pyramid	[redacted]	~$300	$28.52	WAHA
Burlington		~$450	$49.42	N/A

Tri-State forward gas prices change monthly. Figure 3 below shows the current gas forward curve without inflation. Additional transport costs apply.

[redacted]

Figure 3 – Forward Gas Curve

Third Party Assessment

In preparation for Tri-State's 2020 Colorado Electric Resource Plan (ERP) and Western Area Power Administration's Integrated Resource Plan (IRP) processes, Tri-State engaged Black & Veatch (B&V) to assist Tri-State with this assessment of existing resources by reviewing the following items for owned and leased resources:

- Heat Rates
- VOM
- Fixed costs
- Emissions
- Capacity Factors

Additionally, B&V reviewed these items to the extent applicable in regards to the Basin Contract Rate of Delivery (CROD) Western Interconnection contract, Basin Electrically East contract and Renewable Power Agreements[6] .

[6] More detail on these contracts can be found in the Purchase Power Resources section.

Specific areas of recommended change were as follows:

B&V Recommendation	Conclusion
Increase Burlington Heat Rate	Adjustment made to heat rate curve
Change Availability Factor of Combined Cycle resources to 90%	Tri-State will make accommodations in modeling to reflect these changes.
Change Availability Factor of Combustion Turbine dual fuel resources to 96%	Tri-State will make accommodations in modeling to reflect these changes.
Change Availability Factor of Combustion Turbine oil resources to 98%	Tri-State will make accommodations in modeling to reflect these changes.
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.
Increase to Rifle and Shafer SO_2 emission rates	Rifle and 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 forced outage factor for all gas units	Tri-State is reviewing this feedback and will take into consideration current and expected operation of gas and oil units and modify as determined to be necessary.

The Black & Veatch evaluation detail can be found in Appendix A Black & Veatch Report on Review of Existing Resources.

2. Projected Annual Emissions, Energy, Capacity Factors and Availability

This section contains representative scenario data for emissions, energy, capacity factors and availability during the RAP.

Base Case Scenario (typical dispatch):

The following values are based on a "typical" dispatch plan representative of Tri-State's current operations and announced resource additions and retirements. Expansion plan resources are required to support this dispatch. Greenhouse gas reduction requirements in the state of Colorado are not reflected in these numbers. Tri-State anticipates that an appropriate greenhouse gas reduction strategy will be developed in conjunction with the presently ongoing proceedings of the Colorado Air Quality Control Commission (AQCC) and as part of the ERP process.[7]

[7] The retirement of Craig 2 at the end of 2028 as illustrated in this dispatch was one of several possible scenarios. As of July 2020, the Yampa participants have announced a retirement date for Craig 2 of September 30, 2028.

The below calculated emissions are based on generation by resource from the plan and applicable historical emission rates as identified in the Owned & Leased Resources section or Purchased Power Resource section.

Projected CO_2 Emissions (000s of Short Tons)

CO_2	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Craig 1	829	829	829	829	477	0	0	0	0	0
Craig 2	941	947	841	896	495	552	623	569	0	0
Craig 3	3357	3779	3352	3164	1851	2339	2156	2414	2955	0
LRS 2	2116	1847	2104	1935	1826	2116	2106	1872	2021	2031
LRS 3	2246	2144	1986	1933	2280	2039	2283	2281	1955	2198
SPV3	2025	1697	1920	1824	2292	2486	2583	2538	2648	2709
JM Shafer	376	285	46	142	226	182	145	104	111	125
Rifle	1	0	16	0	0	0	0	0	0	0
Limon	10	5	116	5	16	4	1	0	0	0
Knutson	23	16	137	6	14	2	1	0	0	0
Pyramid	11	34	8	5	90	90	84	83	46	37
Burlington	0	0	0	0	0	0	0	0	0	0
Basin CROD Western Interconnection	1815	1815	1815	1821	1815	1815	1815	1821	1815	1815
Basin Electrically East	469	472	476	479	482	486	489	492	496	499

Projected SO_2 Emission (Short Tons)

SO_2	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Craig 1	135	135	135	135	78	0	0	0	0	0
Craig 2	138	139	123	132	73	81	91	84	0	0
Craig 3	2101	2365	2098	1980	1159	1464	1350	1511	1850	0
LRS 2	1058	923	1052	967	913	1058	1053	935	1010	1015
LRS 3	1701	1624	1504	1464	1727	1544	1729	1727	1480	1664
SPV3	793	665	752	714	898	974	1012	994	1038	1061
JM Shafer	2.99	2.27	0.36	1.13	1.80	1.45	1.15	0.82	0.88	1.00
Rifle	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Limon	0.05	0.03	0.62	0.02	0.09	0.02	0.01	0.00	0.00	0.00
Knutson	0.14	0.10	0.83	0.04	0.09	0.01	0.01	0.00	0.00	0.00
Pyramid	0.11	0.33	0.08	0.04	0.88	0.87	0.82	0.81	0.45	0.36
Burlington	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Basin CROD Western Interconnection	1151	1151	1151	1155	1151	1151	1151	1155	1151	1151
Basin Electrically East	530	534	537	541	545	548	552	556	560	563

Projected NOx Emissions (Short Tons)

NOx	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Craig 1	990	990	991	991	570	0	0	0	0	0
Craig 2	269	271	240	256	142	158	178	163	0	0
Craig 3	3611	4064	3605	3404	1991	2516	2319	2596	3179	0
LRS 2	2239	1954	2226	2047	1932	2239	2228	1981	2138	2149
LRS 3	2249	2147	1989	1936	2283	2042	2286	2283	1957	2200
SPV3	745	624	706	671	843	915	950	934	974	997
JM Shafer	287	217	35	108	172	139	110	79	84	95
Rifle	3	0	34	0	0	0	0	0	0	0
Limon	2	1	29	1	4	1	0	0	0	0
Knutson	5	4	31	1	3	1	0	0	0	0
Pyramid	11	34	8	4	89	88	83	82	45	37
Burlington	0	0	0	0	0	0	0	0	0	0
Basin CROD Western Interconnection	1867	1867	1867	1872	1867	1867	1867	1872	1867	1867
Basin Electrically East	378	381	384	387	389	392	394	397	400	402

Projected Particulate Matter Emissions (Short Tons)

PM	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Craig 1	16	16	16	16	9	0	0	0	0	0
Craig 2	20	20	18	19	11	12	13	12	0	0
Craig 3	106	120	106	100	59	74	68	76	94	0
LRS 2	98	86	98	90	85	99	98	87	94	95
LRS 3	178	170	157	153	180	161	181	180	155	174
SPV3	32	26	30	28	36	39	40	39	41	42
JM Shafer	31	24	4	12	19	15	12	9	9	10
Rifle	0.26	0.00	3.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Limon	0.42	0.21	4.99	0.20	0.71	0.15	0.05	0.00	0.00	0.00
Knutson	1.94	1.32	11.37	0.51	1.17	0.20	0.10	0.00	0.00	0.00
Pyramid	0.62	1.94	0.46	0.26	5.13	5.12	4.79	4.73	2.61	2.12
Burlington	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Basin CROD Western Interconnection	107	107	107	108	107	107	107	108	107	107
Basin Electrically East	UA	UA	UA	UA	UA	UA	UA	UA	UA	UA

UA = Unavailable[8]

[8] Data was not available for this sub region for particulate matter emissions.

Projected Mercury Emissions (Short Tons)

hg	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Craig 1	0.007	0.007	0.007	0.007	0.004	0.000	0.000	0.000	0.000	0.000
Craig 2	0.006	0.006	0.005	0.006	0.003	0.004	0.004	0.004	0.000	0.000
Craig 3	0.135	0.152	0.135	0.127	0.074	0.094	0.087	0.097	0.119	0.000
LRS 2	0.042	0.037	0.042	0.039	0.037	0.042	0.042	0.038	0.041	0.041
LRS 3	0.047	0.045	0.042	0.040	0.048	0.043	0.048	0.048	0.041	0.046
SPV3	0.016	0.014	0.016	0.015	0.019	0.020	0.021	0.021	0.022	0.022
JM Shafer	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
Limon	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Knutson	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Burlington	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin CROD Western Interconnection	0.035	0.035	0.035	0.035	0.035	0.035	0.035	0.035	0.035	0.035
Basin Electrically East	UA	UA	UA	UA	UA	UA	UA	UA	UA	UA

UA = Unavailable[9]

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 4 and 5 below 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 4 – Basin CROD Western Interconnection Stegall West 230KV Bus Hourly Profile

[9] Data was not available for this sub region for mercury emissions.

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	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 5 – Basin CROD Western Interconnection AU 230KV and STORY 230KV busses Hourly Profile

Basin Electrically East contract has an energy and demand profile based on forecasted 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 6 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.

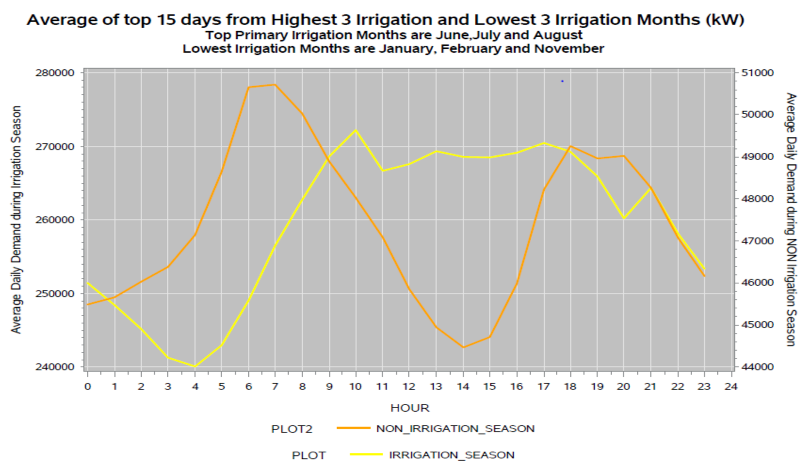


Figure 6 – Basin Electrically East Irrigation and Non-Irrigation Seasons Demand Profiles

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

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

Annual Projected Energy and Demand by Contract

Energy (GWh)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Basin CROD Western Interconnection[10]	1575	1575	1575	1580	1575	1575	1575	1580	1575	1575
Basin Electrically East [11]	757	762	767	773	778	783	788	795	800	805

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	1671	1683	1694	1705	1716	1727	1739	1751	1762	1773

Projected WAPA Contracts – Loveland Area Projects (LAP) and Colorado River Storage Projects (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.

Annual Projected Energy and Demand 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

[10] Energy is delivered to Colorado and Wyoming.
[11] ~15% of this purchase serves Colorado. Balance of purchase serves load in Nebraska.

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

Annual Demand [12] (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

Projected Annual Capacity Factors for Thermal Resources

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Craig 1	80%	80%	80%	80%	46%	0%	0%	0%	0%	0%
Craig 2	93%	94%	83%	89%	49%	55%	62%	56%	0%	0%
Craig 3	82%	92%	82%	77%	45%	57%	53%	59%	72%	0%
LRS 2	95%	82%	94%	86%	82%	95%	94%	84%	90%	91%
LRS 3	92%	88%	81%	79%	93%	83%	93%	93%	80%	90%
SPV3	52%	43%	49%	47%	59%	64%	66%	65%	68%	69%
JM Shafer	32%	24%	4%	12%	19%	16%	12%	9%	9%	11%
Rifle	0%	0%	3%	0%	0%	0%	0%	0%	0%	0%
Limon	1%	1%	13%	1%	2%	0%	0%	0%	0%	0%
Knutson	3%	2%	15%	1%	2%	0%	0%	0%	0%	0%
Pyramid	1%	4%	1%	1%	10%	10%	10%	10%	5%	4%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Projected Availability Factors 2021 to 2030 for Thermal Resources

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 is currently updating its models to reflect recommended forced outage factors as provided by Black & Veatch (Appendix A).

[12] Representative of monthly billing demands per the contracts. Actual maximum available hourly capacity in any given month varies.

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						

3. Purchased Power Resources

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 Power Purchase Agreements 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.

Contract Purchases:

Basin CROD Western Interconnection BEPC: Colorado & Wyoming: 268 MW summer capacity, ~1580 GWh/year[13]. Effective Date 1/16/1975; Renewed 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.

Basin Electrically East BEPC: All Requirements Purchase Contract for Electrically East Loads[14], Effective Date 1/16/1975; Renewed 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.

[13] Profile detail is shown in Projected Annual Emissions, Capacity Factors and Availability section
[14] Profile detail is shown in Projected Annual Emissions, Capacity Factors and Availability section

- 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 70% 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

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).

Energy and Capacity Payments for Contract Purchases

The following rates are averaged over the RAP:

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

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.

[15] Composite rate encompassing energy and demand components
[16] Composite rate encompassing energy and demand components

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 are as follows:

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:

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	

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 modify energy 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.

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 Associated with Contract Purchases and Renewable Purchase Power Agreements

Tri-State receives Renewable Energy Credits (RECs) associated with its Renewable Purchase Power Agreements.

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.

Historical emissions for Basin CROD Western Interconnection and Basin Electrically East contracts are estimated below:

Estimated Historical Emission Rates

lbs. per MWH	CO_2	SO_2	NOx	PM	Hg
Basin CROD Western Interconnection	2305	1.462	2.3705	.13615	.00004395
Basin Electrically East	1239.8	1.4	1.0	UA	UA

UA= Unavailable[17]

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 information filing, Tri-State considered the following:

Basin CROD Western Interconnection Contract: Historically this contract has been primarily served by LRS generation so an average of LRS 2 and LRS 3 emissions factors was used. 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. Given this, the egrid[18] sub region of MRO West was used as a proxy to represent emissions for this contract. The total output emission rates were used for CO_2, NOx and SO_2.

Additionally, we note that Tri-State receives RECs related to both of the Basin contracts as a member of BEPC under an associated board policy.

While the above emissions for Tri-State's Basin contracts are estimates based on historical sourcing only, Tri-State will explore further the projected emissions sources for each of these contracts within the bounds of the Colorado AQCC regulations, both currently effective and under development, during its ERP process leading to the December 1 filing to accurately reflect the emissions of these contracts and their impact on carbon reduction in future years.

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 May 2020, 66 renewable or distribution generation projects, totaling 136 MW of capacity and capable of producing ~380 GWh/year are operating or under development. Approximately 85% of

[17] Data for this sub region was not available for particulate matter or mercury emissions.
[18] Environmental Protection Agency - egrid 2018 Summary Tables

Utility Member system distributed generation is located in Colorado, and on a capacity basis, approximately 75% 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 Members 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 Members' service territories.

These resources are not owned by, or contracted to, Tri-State, but instead serve Utility Member system load directly, so Tri-State has not attempted to provide a detailed assessment of these generation projects.

4. Demand Side Management & Energy Efficiency

As reported in Tri-State's 2019 Annual Progress Report an ongoing part of Tri-State's Action Plan is the implementation of Demand Side Management (DSM) and Energy Efficiency (EE) programs. 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 member feedback. As a reminder, Tri-State does not have retail load and is reliant upon Utility Member system participation in DSM and EE program implementations.

<u>Current offerings for Demand Side Management include:</u>

- Demand Response (DR) related to air conditioning, water heating and irrigation
    - Four Utility Member systems currently have irrigation DR programs
- Energy shaping related to electric thermal storage and electric vehicle charging station
    - Eleven Utility Member systems use time of use rates for storage heater control
    - Several Utility Member systems are investigating or have implemented residential demand rates in an attempt to control/shift load during peak times

Tri-State's current A-40 rate structure 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. Many 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.

<u>Current offerings for Energy Efficiency include:</u>

- Heat Pump Projects working with the Electric Power Research Institute (EPRI) and our Utility Member systems
- Rebates on education programs for training in Energy Auditing
- Irrigation program to educate Utility Member systems in regards to efficiency
- Incentives are offered in many areas such as residential and commercial lighting, appliances, air conditioning, motors, air and ground source heat pumps and assisting in energy efficient education and training

Year End 2018[19] Cumulative Energy Efficiency Results:

Category	Typical Measures	kW Savings	kWh Savings
Agriculutural	Irrigation Motors Variable Speed Drive Retrofits	13,080	21,902,726
C&I HVAC	Air Source and Ground Source Heat Pumps	7,275	9,263,112
C&I Lighting	LED Lighting Street & Parking Lot Lighting Refrigerated Case Doors	25,434	91,528,578
C&I Motors	Variable Speed Drive Retrofits	3,968	8,199,393
Residential HVAC	Air Conditioners Air Source and Ground Source Heat Pumps	83,891	57,344,907
Residential - Othe	LED Lamps, Energy Star Appliances Electric Water Heaters Low Income Weatherization	51,488	23,905,259
Total		**185,136**	**212,143,975**

Energy Efficiency Rebate History

- 2014 - $2,131,637
- 2015 - $2,128,582

[19] Table identifier corrected to 2018 from 2019 as shown in June 1 filing.

- 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 Demand Side Management (DSM) and Energy Efficiency (EE) Potential study with an outside consultant with the goal of receiving updated information in regards to achievable potential and cost savings in these areas 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 its DSM and EE products and services in a manner that is beneficial to Tri-State and Utility 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 but 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 Appendix C to this report.

5. Benchmarking

For the purposes of the Rule 3605(c)(II) Benchmarking requirement, Tri-State engaged Black and 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 contracts 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 Black & Veatch Benchmarking process are located in Appendix B: Black & Veatch Report on Benchmarking of Existing Resources

6. Ancillary Service Assessment

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 PacifiCorp, PSCo, Public Service of New Mexico 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.

The following is a list of the primary ancillary services required via applicable Open Access Transmission Tariffs and how Tri-State acquires these services including any applicability to Tri-State resources:

Scheduling, System Control & Dispatch: Tri-State pays for this service monthly from appropriate Transmission Providers or Balancing Authorities. Tri-State Resources do not have any impact on or relation to this service.

Reactive Supply & Voltage Control: Tri-State pays for this service monthly from appropriate Transmission Providers or Balancing Authorities. 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.

Regulation and Frequency Response (includes load following capabilities): Tri-State pays for this service monthly from appropriate Transmission Providers or Balancing Authorities. 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.

Tri-State generating resources that are AGC capable include:

- Craig 1, 2, and 3
- LRS 2
- Springerville 3
- JM Shafer
- Knutson 1,2
- Limon 1,2
- Pyramid 1,2,3,4
- Burlington 1,2

Energy Imbalance Service: Tri-State currently pays for this service monthly from appropriate Transmission Providers or Balancing Authorities. Beginning in 2021, a portion of Tri-State's load and resources will be in two energy imbalance markets – the Western Energy Imbalance Service (WEIS) and the Western Energy Imbalance Market (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.

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. Tri-State generating resources typically online and capable of carrying spinning reserves include:

- Craig 1
- Craig 2
- Craig 3
- LRS2
- LRS3
- Springerville 3
- JM Shafer

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.

Operating Reserve Supplemental Service:

Tri-State self-supplies spinning reserves through Southwest Reserve Sharing Group member and via two sub-entity Reserve Sharing Group Agreements. Tri-State generating resources with quick start capability to qualify for supplemental service include:

- Burlington 1,2
- Limon 1,2
- Pyramid 1,2,3,4

Generator Imbalance Service: Tri-State currently takes and pays for this service monthly from appropriate Transmission Providers or Balancing Authorities. 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.

Flex Reserve Service: Tri-State currently takes and pays for this service monthly from appropriate Transmission Providers or Balancing Authorities. 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.

Loss Supply Service: Tri-State either pays for this service monthly from appropriate Transmission Providers or Balancing Authorities or provides physical loss requirement depending on specific contractual arrangements.

Confidential Information

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

- Scheduled Outage Plan (Maintenance

Highly Confidential Information

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

- Fixed O&M Expenses
- Variable O&M Expenses
- Fuel Price Forward Curves (Gas and Coal)
- Contract/PPA Energy Rate, except in regards to Tri-State's LAP and CRSP hydro power purchase contracts with WAPA.
- Contract/PPA Capacity Rate, except in regards to Tri-State's LAP and CRSP hydro power purchase contracts with WAPA.
- Performance or Operating Output guarantees and any associated pricing adjustments included in Tri-State' Renewable Power Purchase Agreements
- Any information protected by a confidentiality clause in a PPA

Appendix A: Black & Veatch Report on Review of Existing Resources

BLACK & VEATCH

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)

	Resource	Non-Fuel Variable O&M Costs per MWh							
		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	[redacted]	None	3.37	3.62	3.49	No change	S&P data not actual	[redacted]
3	GC-Craig 3-NW_CO	[redacted]	None	3.37	3.62	3.49	No change	S&P data not actual	[redacted]
4	GC-LRS 2-WY	[redacted]	None	2.58	3.62	3.10	No change	S&P data not actual	[redacted]
5	GC-LRS 3-WY	[redacted]	None	2.58	3.62	3.10	No change	S&P data not actual	[redacted]
6	GC-SV 3-SPV	[redacted]	None	5.89	3.62	4.75	No change	S&P data not actual	[redacted]
7	GG-Burlington 1-E_CO	[redacted]	None	88.57	14.97	51.77	No change	S&P data reflects extreme year	[redacted]
8	GG-Burlington 2-E_CO	[redacted]	None	88.57	14.97	51.77	No change	S&P data reflects extreme year	[redacted]
9	GG-Knutson 1-E_CO	[redacted]	None	15.26	14.97	15.11	No change	S&P data reflects extreme year	[redacted]
10	GG-Knutson 2-E_CO	[redacted]	None	15.26	14.97	15.11	No change	S&P data reflects extreme year	[redacted]
11	GG-Limon 1-E_CO	[redacted]	None	5.67	14.97	10.32	No change	S&P data reflects extreme year	[redacted]
12	GG-Limon 2-E_CO	[redacted]	None	5.67	14.97	10.32	No change	S&P data reflects extreme year	[redacted]
13	GG-Pyramid 1-S_NM	[redacted]	None	6.49	8.69	7.59	No change	S&P data not actual	[redacted]
14	GG-Pyramid 2-S_NM	[redacted]	None	6.49	8.69	7.59	No change	S&P data not actual	[redacted]
15	GG-Pyramid 3-S_NM	[redacted]	None	6.49	8.69	7.59	No change	S&P data not actual	[redacted]
16	GG-Pyramid 4-S_NM	[redacted]	None	6.49	8.69	7.59	No change	S&P data not actual	[redacted]
17	GG-Rifle-NW_CO	[redacted]	None	8.32	3.23	5.77	No change	Within reasonable range	[redacted]
18	GG-Shafer-E_CO	[redacted]	None	3.75	1.63	2.69	No change	S&P data skewed by 2017 value	[redacted]
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	[redacted]	None	42.62	27.77	35.19	No change	S&P data poor quality (duplicative, missing)	98	[redacted]	[redacted]
3 GC-Craig 3-NW_CO	[redacted]	None	42.62	27.77	35.19	No change	S&P data poor quality (duplicative, missing)	448	[redacted]	[redacted]
4 GC-LRS 2-WY	[redacted]	None	28.01	27.77	27.89	No change	S&P data poor quality (duplicative, missing)	231	[redacted]	[redacted]
5 GC-LRS 3-WY	[redacted]	None	28.01	27.77	27.89	No change	S&P data poor quality (duplicative, missing)	230	[redacted]	[redacted]
6 GC-SV 3-SPV	[redacted]	None	49.73	27.77	38.75	No change	S&P data poor quality (duplicative, missing)	417	[redacted]	[redacted]
7 GG-Burlington 1-E_CO	[redacted]	None	4.68	3.55	4.12	No change	S&P data poor quality (duplicative, missing)	55	[redacted]	[redacted]
8 GG-Burlington 2-E_CO	[redacted]	None	4.68	3.55	4.12	No change	S&P data poor quality (duplicative, missing)	55	[redacted]	[redacted]
9 GG-Knutson 1-E_CO	[redacted]	None	3.62	3.55	3.58	No change	S&P data poor quality (duplicative, missing)	70	[redacted]	[redacted]
10 GG-Knutson 2-E_CO	[redacted]	None	3.62	3.55	3.58	No change	S&P data poor quality (duplicative, missing)	70	[redacted]	[redacted]
11 GG-Limon 1-E_CO	[redacted]	None	3.62	3.55	3.58	No change	S&P data poor quality (duplicative, missing)	70	[redacted]	[redacted]
12 GG-Limon 2-E_CO	[redacted]	None	3.62	3.55	3.58	No change	S&P data poor quality (duplicative, missing)	70	[redacted]	[redacted]
13 GG-Pyramid 1-S_NM	[redacted]	None	3.51	6.34	4.92	No change	S&P data poor quality (duplicative, missing)	55	[redacted]	[redacted]
14 GG-Pyramid 2-S_NM	[redacted]	None	3.51	6.34	4.92	No change	S&P data poor quality (duplicative, missing)	55	[redacted]	[redacted]
15 GG-Pyramid 3-S_NM	[redacted]	None	3.51	6.34	4.92	No change	S&P data poor quality (duplicative, missing)	70	[redacted]	[redacted]
16 GG-Pyramid 4-S_NM	[redacted]	None	3.51	6.34	4.92	No change	S&P data poor quality (duplicative, missing)	70	[redacted]	[redacted]
17 GG-Rifle-NW_CO	[redacted]	None	26.68	14.44	20.56	25.00	Current modeled very high	52	[redacted]	[redacted]
18 GG-Shafer-E_CO	[redacted]	None	14.64	11.08	12.86	No change	Within reasonable range	14	[redacted]	[redacted]
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)

Resource	SO2 Emission Rate (lb/MMBtu) 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 (%)

Resource	Forced Outage Factor (%) 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

BLACK & VEATCH

END OF REPORT

Appendix B: Black & Veatch Report on Benchmarking of Existing Resources

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

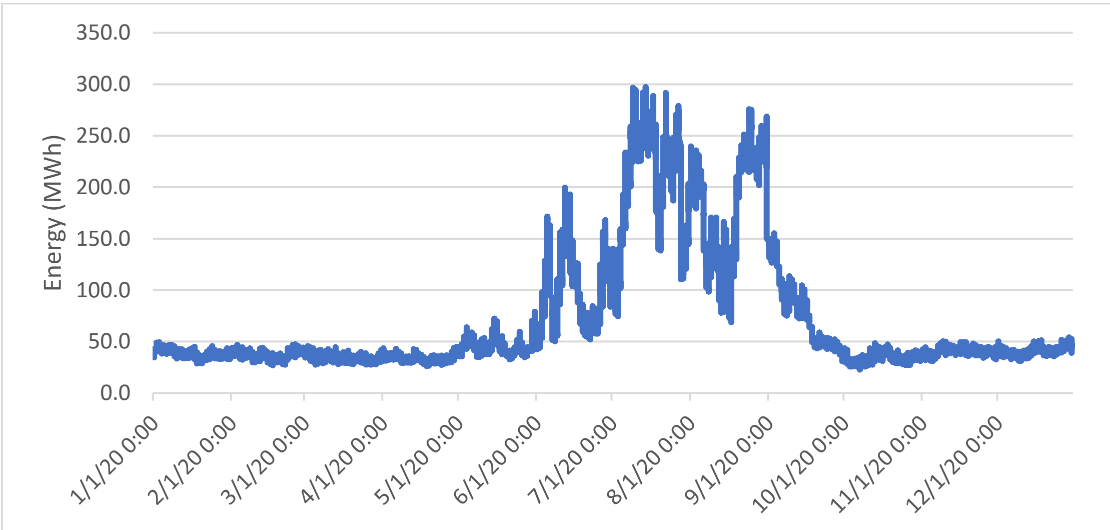
Selection Criteria. We set the Common Capacity Factor for the Pairing equal to fifteen (15) percent which is representative for combustion turbine resources.

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	
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)	[redacted]	
Fuel Cost 2021 ($/MMBtu)	[redacted]	0.2%
VOM Cost 2021 ($/MWh)	[redacted]	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**	

Calculate LCOE and

Detail

	Generation (GWh)	Fuel	VOM	Social Cost of Carbon	FOM	Book: Capex Balance	Book: Capex	Book: Interest	Book: Depreciation	Book: 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

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August 3, 2020 Revision

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	[redacted]	$33		
20	CP-SanIsabel-E_CO	CP-1x100PV_eco	n/a	n/a	[redacted]	$28		
21	CP-FirstSolar-N_NM	CP-1x100PV_nnm	n/a	n/a	[redacted]	$33		
22	CP-ColoHighlands-E_CO	CP-1x100Wind_eco	n/a	n/a	[redacted]	$30		
23	CP-KitCarson-E_CO	CP-1x100Wind_eco	n/a	n/a	[redacted]	$30		
24	CP-TwinButtes-E_CO	CP-1x100Wind_eco	n/a	n/a	[redacted]	$30		
25	CP-Carousel-E_CO	CP-1x100Wind_eco	n/a	n/a	[redacted]	$30		
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	[redacted]	$112		

Figure 2 – Comparison of LCOE for Thermal Resource Pairings

[redacted]

Figure 3 – Comparison of LCOC for Thermal Resource Pairings

[redacted]

Figure 4 – LCOE Comparison for the Renewable Resource Pairings

[redacted]

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	[redacted]			
21	CP-FirstSolar-N_NM	CP-1x100PV_nnm	n/a	n/a	[redacted]	$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	[redacted]	$91		

END OF REPORT

Appendix C: Mesa Point Energy & BrightLine Group - Tri-State Demand Side Management and 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

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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

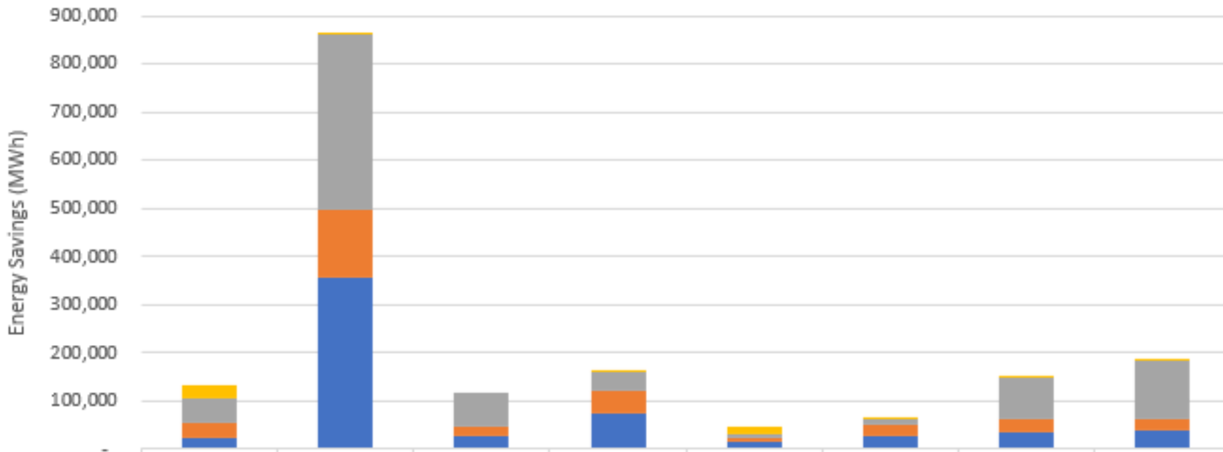
As summarized in Table ES-1, the Mesa Point Team found that the Achievable-moderate scenario would result in approximately 38 GWh (0.25% of sales) of energy efficiency saving in 2021 rising to 1,718 GWh (8.16% of sales) of savings through 2040.

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

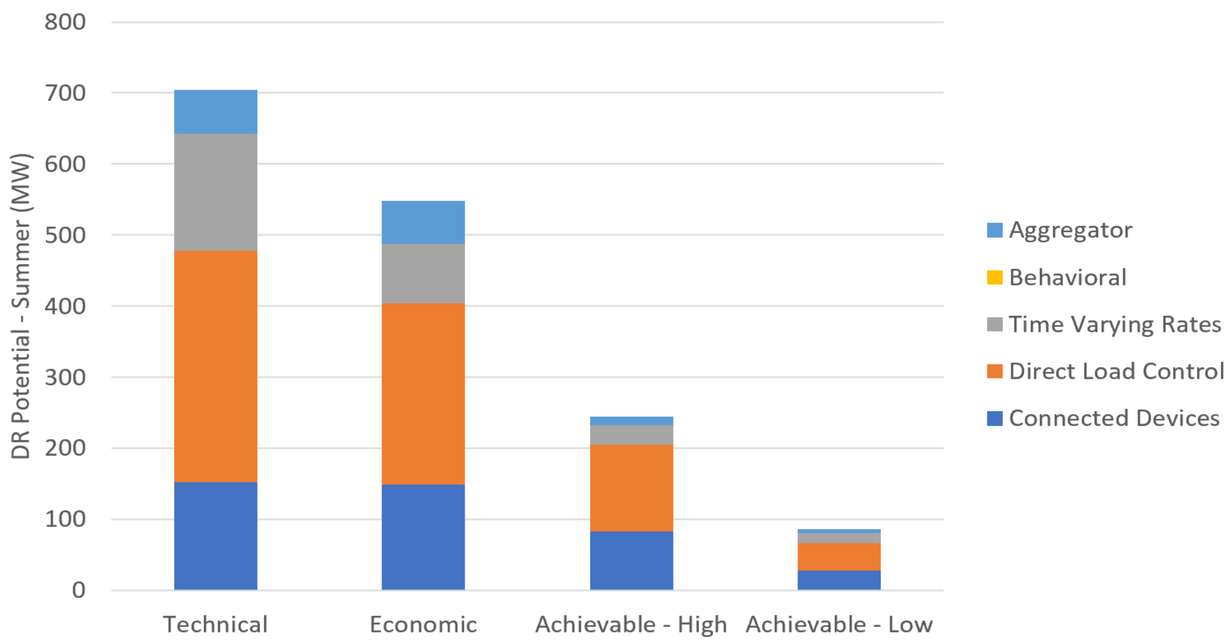
The study considered five different types of DR programs:

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

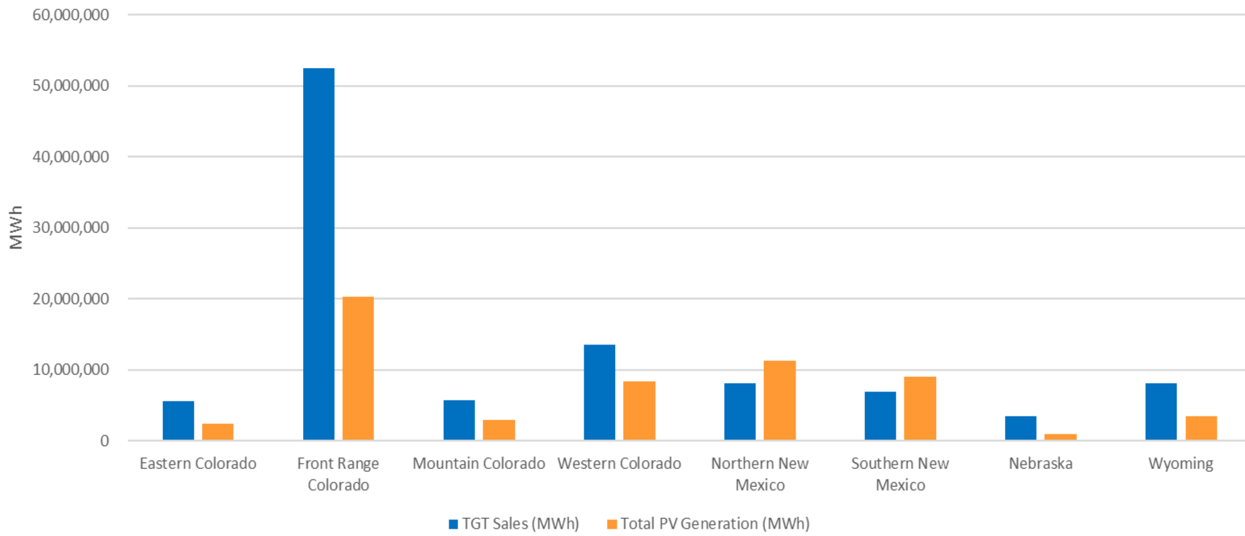
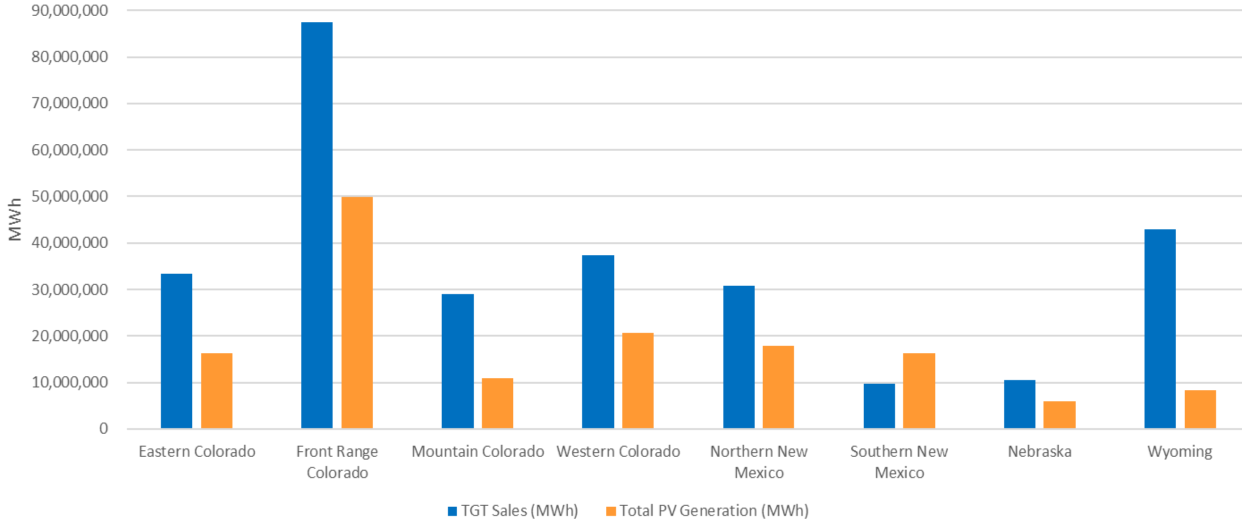
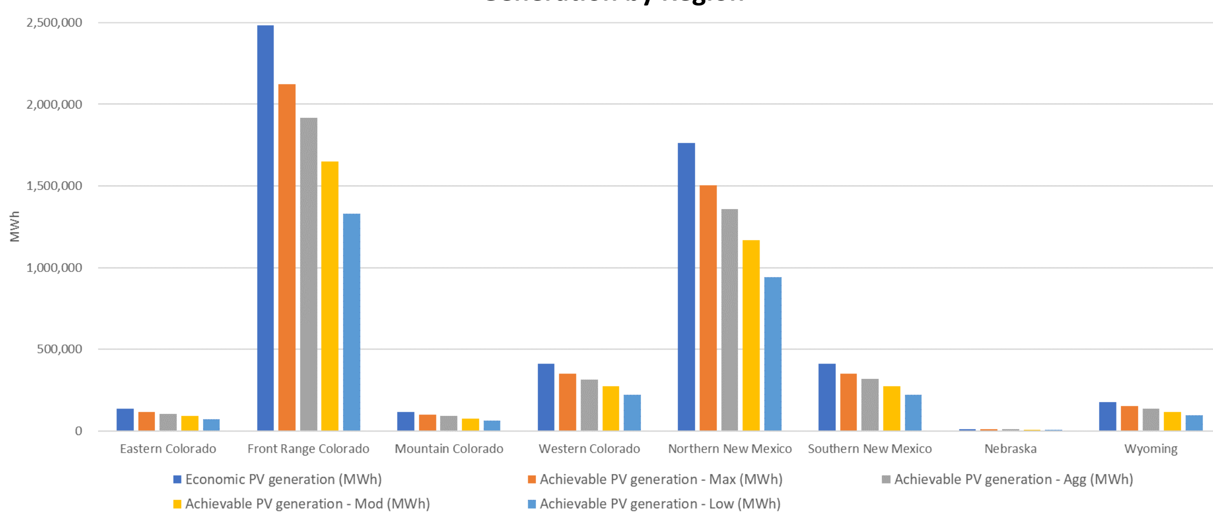


Figure ES-4. 2040 Technical Potential for Cumulative Non-Residential PV Generation vs Sales by Region



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

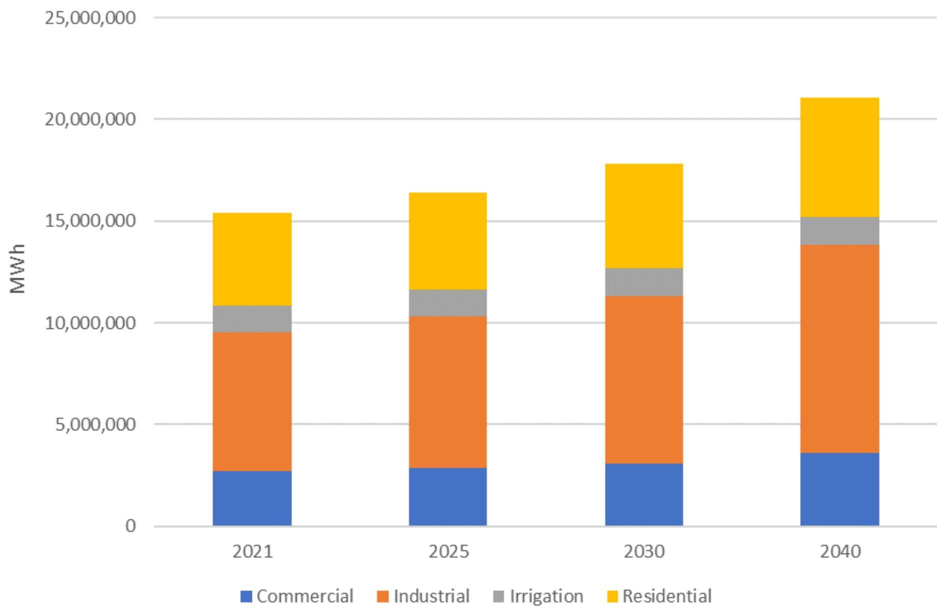
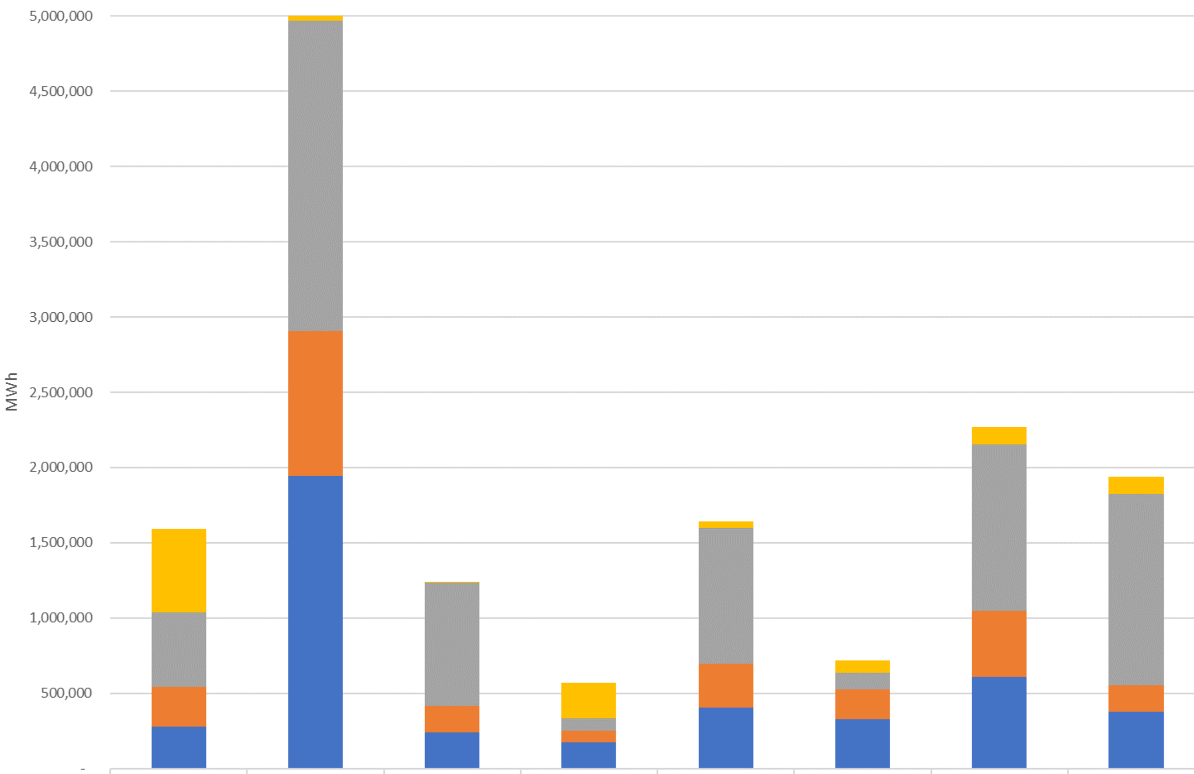


Figure ES-6. 2018 Baseline Energy Load by Customer Sector by Region



	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.

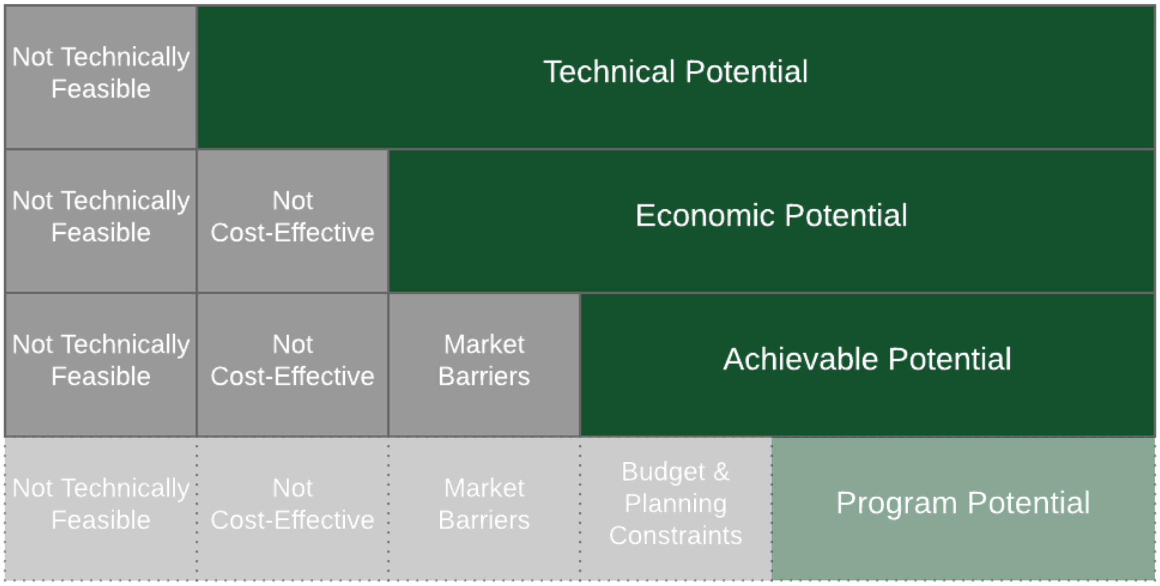
1.3. Study Approach Overview

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

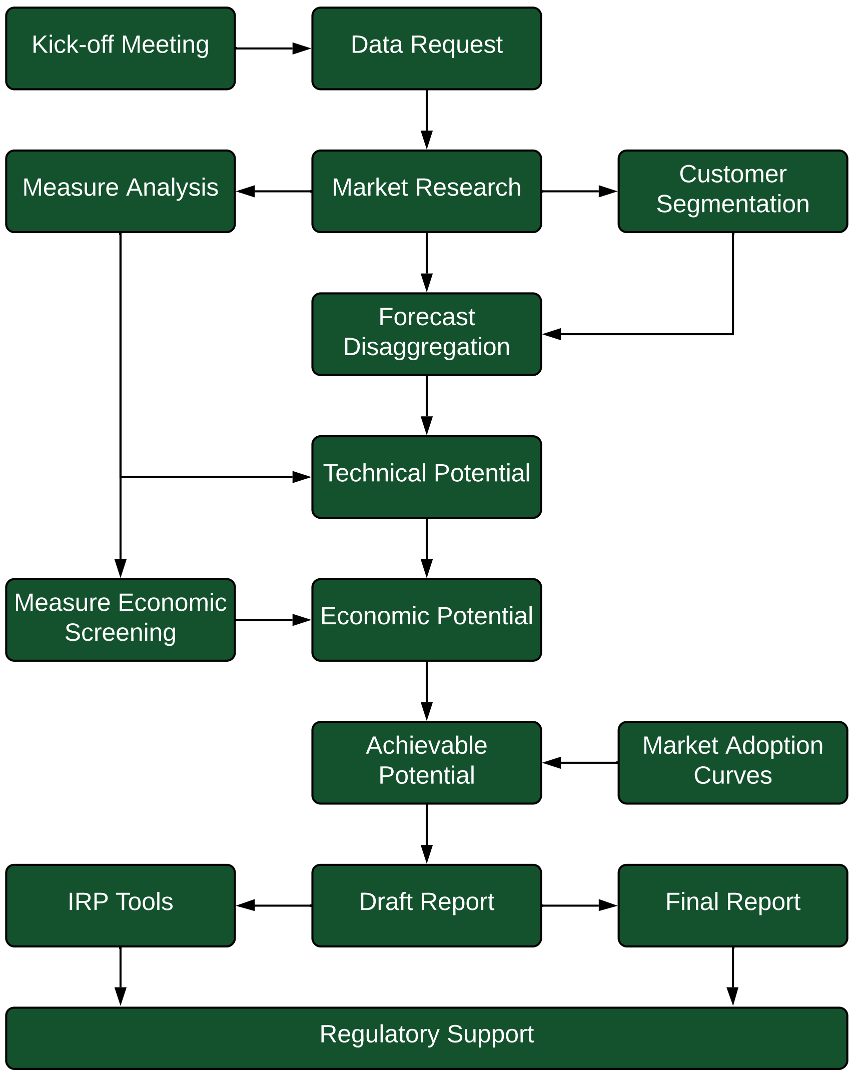
- Presents overall findings and recommendations.

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.

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[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

Technical Potential of Efficient Measures = Total Number of Households + Base Case Equipment Energy Use Intensity (kWh/unit) + Saturation Share + Remaining Factor + Applicability Factor + Savings Factor

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

$$\mathbf{TRC\ Ratio} = \mathbf{NPV}(\mathbf{Avoided\ Costs})/\mathbf{NPV}(\mathbf{Incremental\ Measure\ Costs})$$

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")

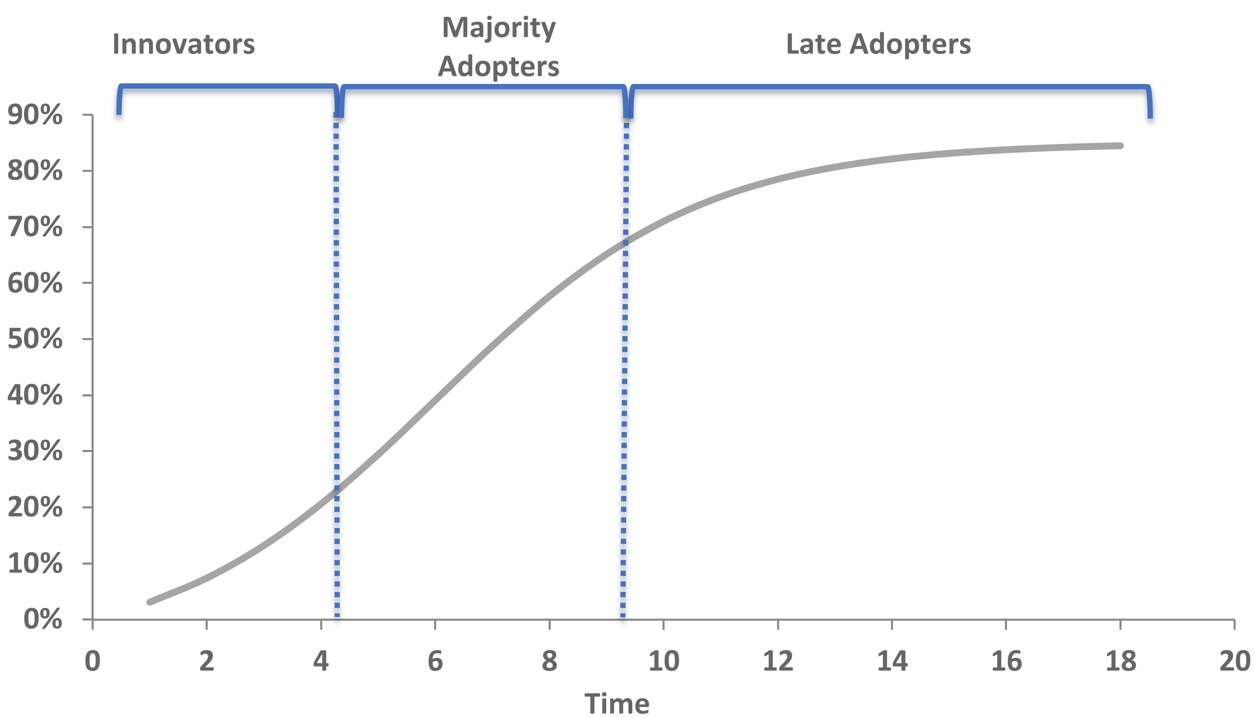
For instance, the moderate scenario approximates the market adoption achievable by incentivizing 50% of the incremental cost of the measure. Results are presented from the perspective of the Achievable Moderate scenario unless otherwise specified. This scenario represents a reasonable progression from 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

$$\boldsymbol{PV\ Technical\ Potential} = \Sigma(\boldsymbol{Suitable\ Rooftop\ Square\ Footage} \times \boldsymbol{PV\ System\ Generation\ per\ Sq.Ft.})$$

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

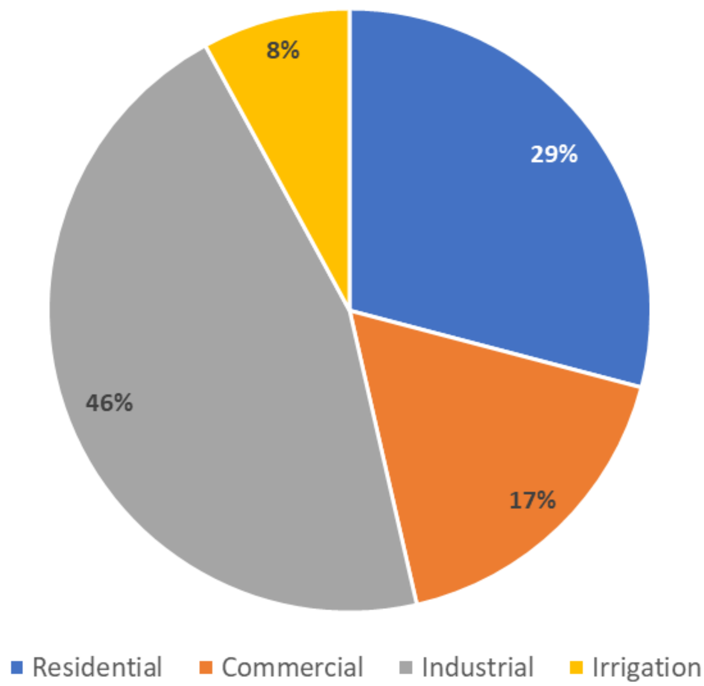


Figure 6. 2018 Energy Sales by Region

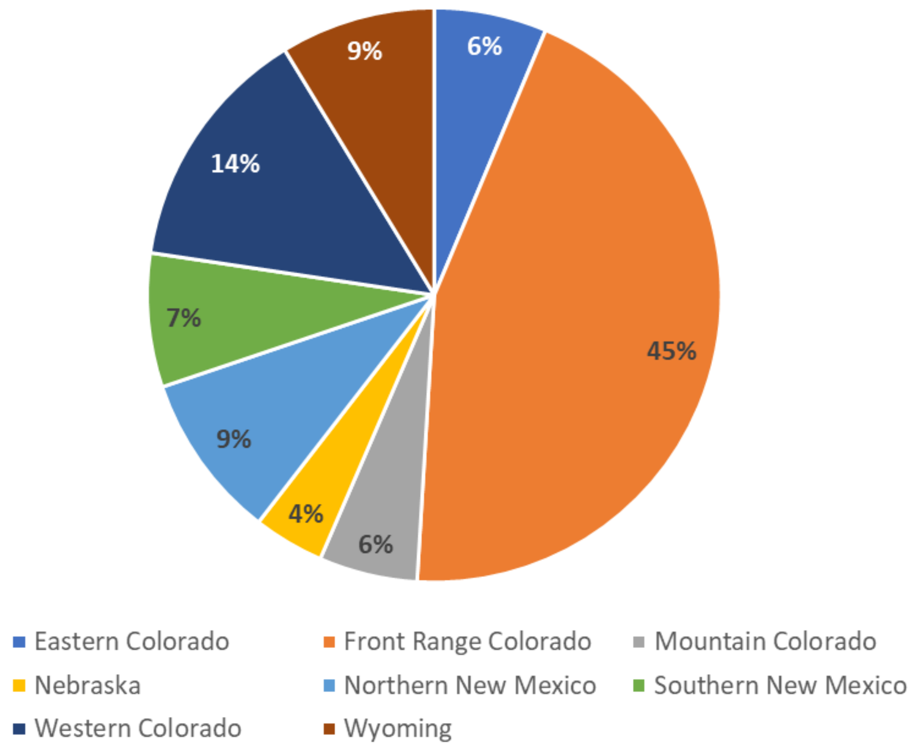
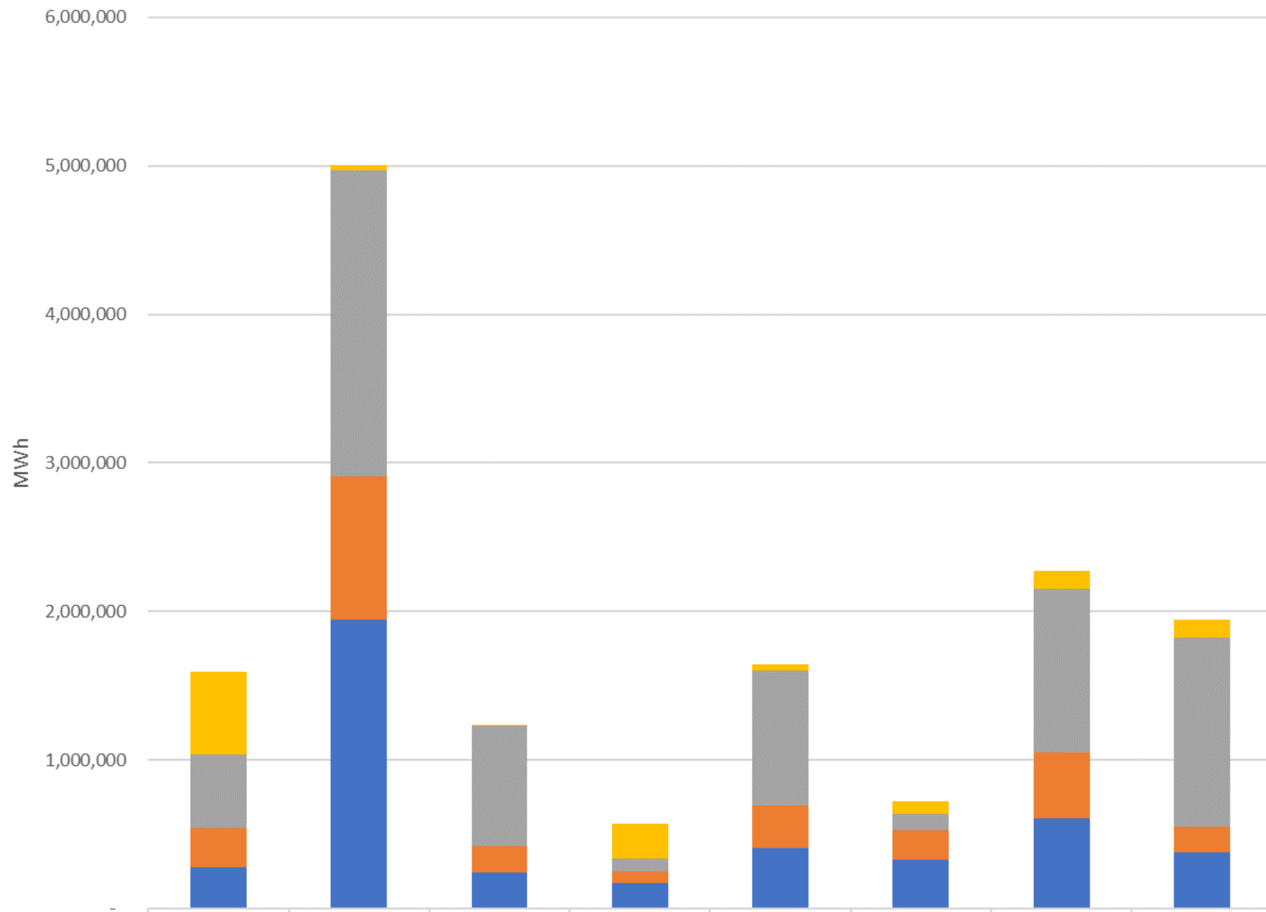


Figure 7. 2018 Energy Sales by Customer Sector and Region



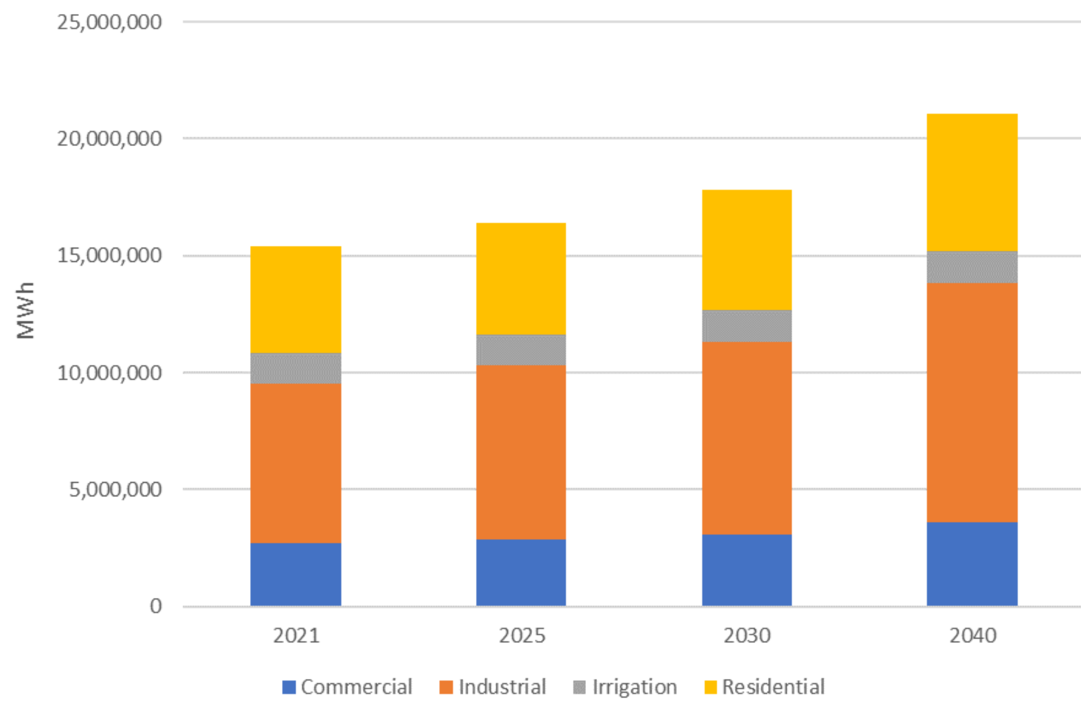
	Eastern Colorado	Front Range Colorado	Mountain Colorado	Nebraska	Northern New Mexico	Southern New Mexico	Western Colorado	Wyoming
Irrigation	554,724	31,967	861	237,972	41,763	85,091	116,352	119,890
Industrial	494,719	2,061,346	814,705	79,803	903,438	107,893	1,104,101	1,268,084
Commercial	268,177	964,547	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

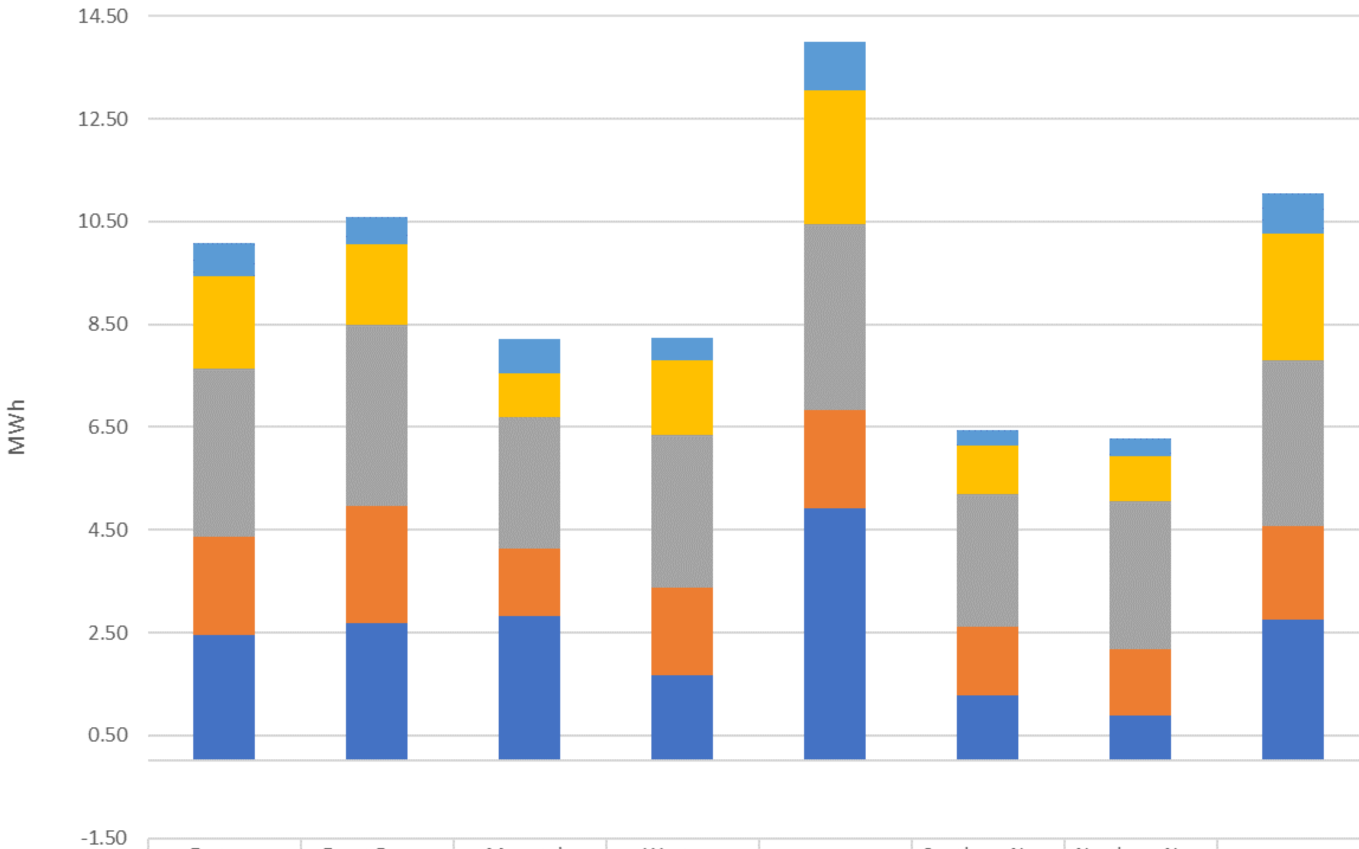


3.2. Residential End-Uses and Loads

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.

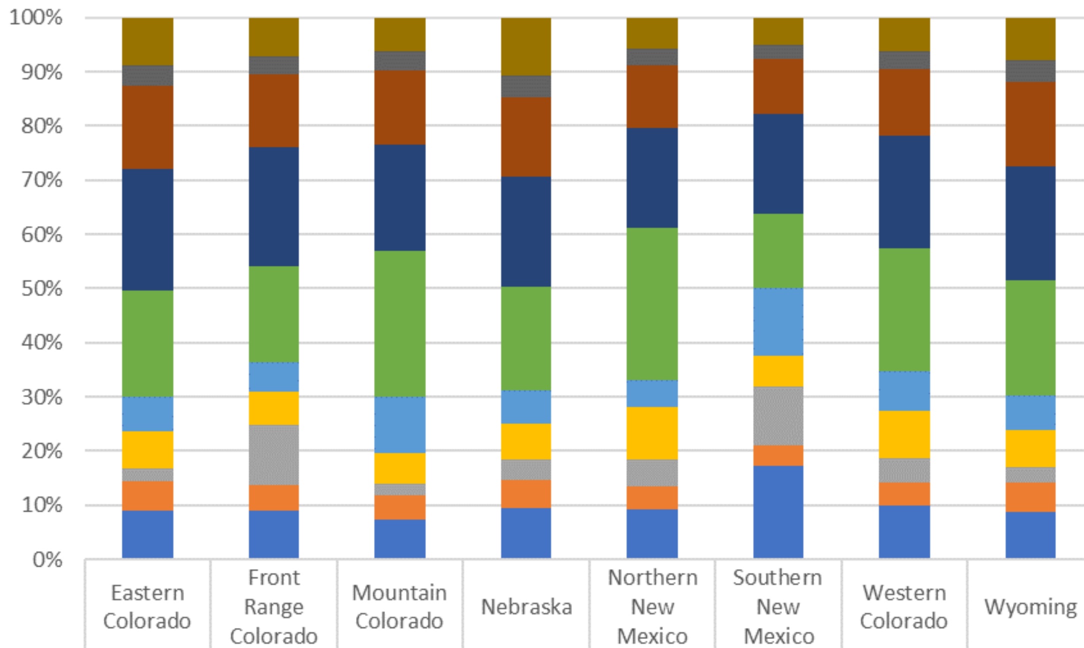
The analysis finds lower appliance saturations and smaller premise square footage for the New Mexico region residences. As expected, there is a higher prevalence of electric space and water heating in the colder climates of mountain Colorado, Nebraska, and Wyoming due to the lack of available natural 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)

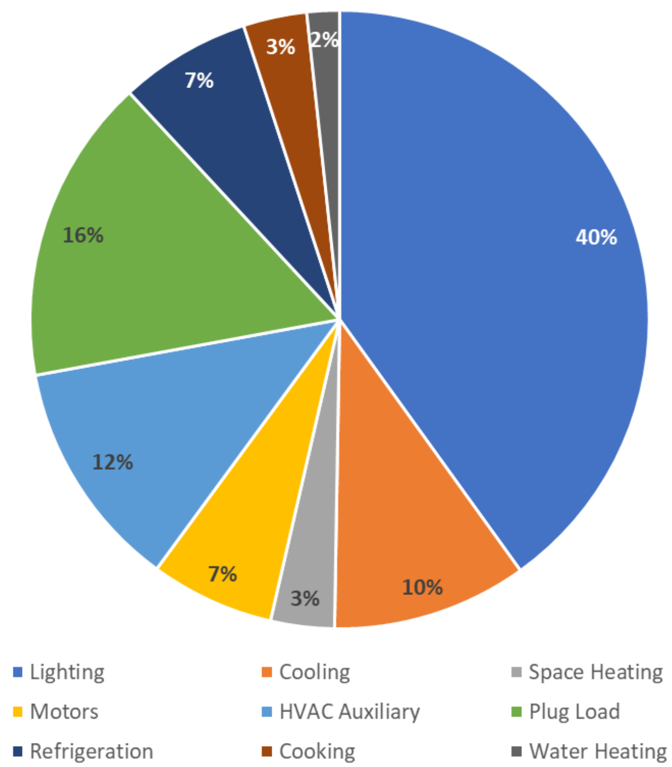


	Eastern Colorado	Front Range Colorado	Mountain Colorado	Nebraska	Northern New Mexico	Southern New Mexico	Western Colorado	Wyoming
Warehouse	9%	7%	6%	11%	6%	5%	6%	8%
Restaurant	4%	3%	3%	4%	3%	3%	3%	4%
Office	15%	13%	14%	15%	12%	10%	12%	15%
Retail	22%	22%	20%	20%	18%	18%	21%	21%
Miscellaneous	20%	18%	27%	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

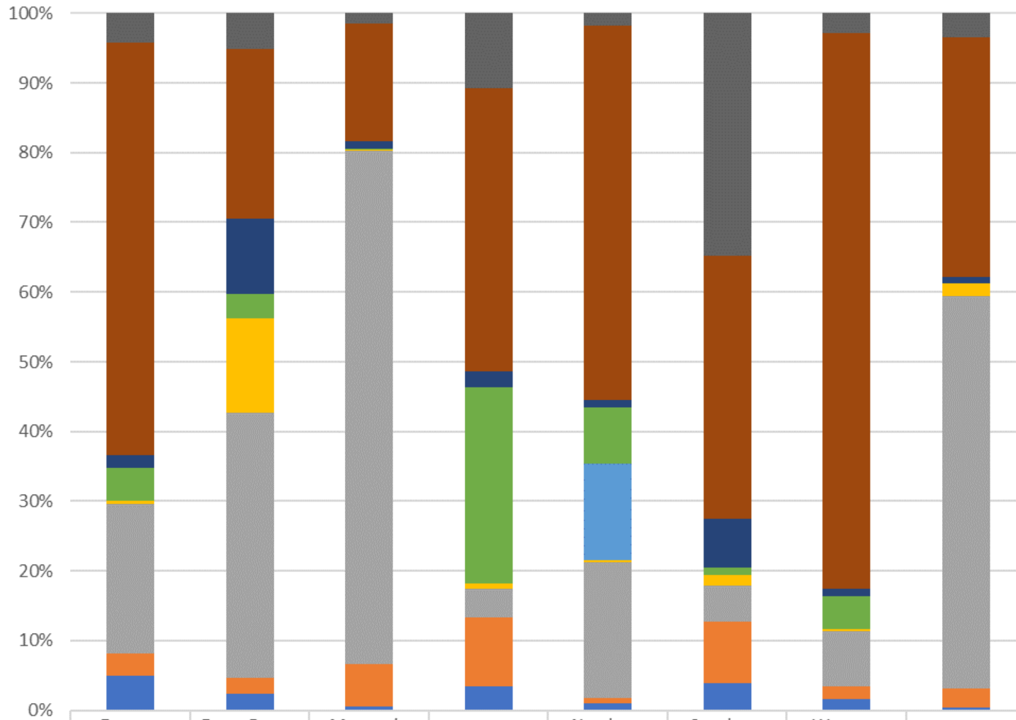


3.4. Industrial End-Uses and Loads

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.

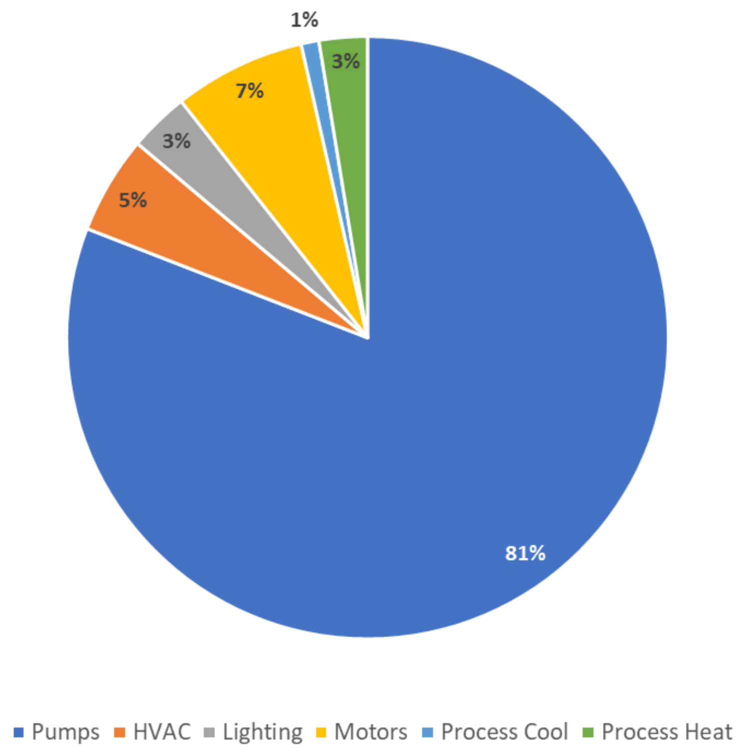
Figure 12. Industrial Sector Energy Shares by Business Segment and Region (2018)



	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).

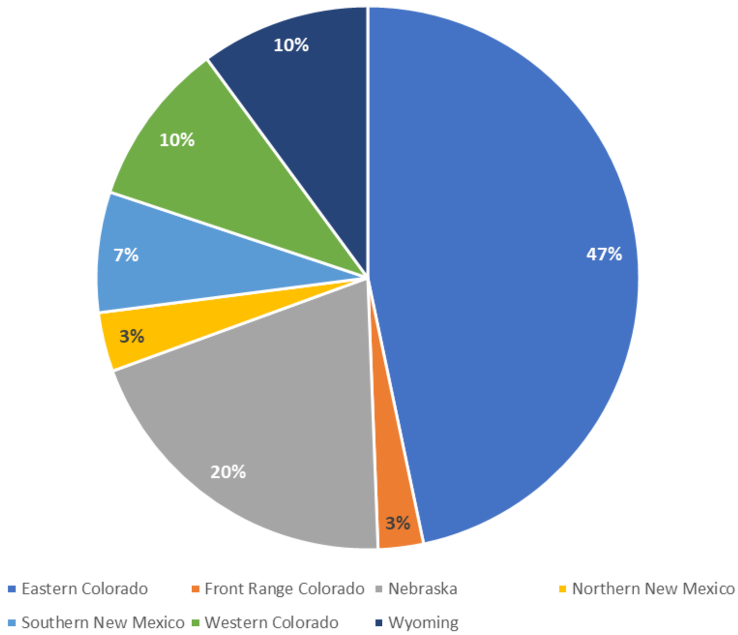
Figure 13. Industrial Sector Energy Shares by End-Use



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

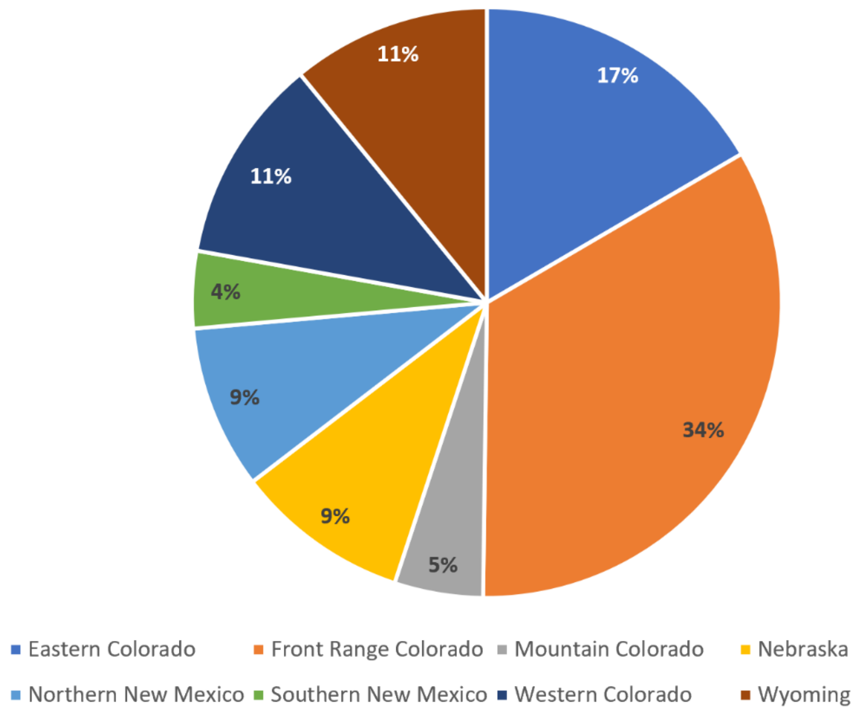


Figure 16. 2018 Coincident Peak Demand by Sector

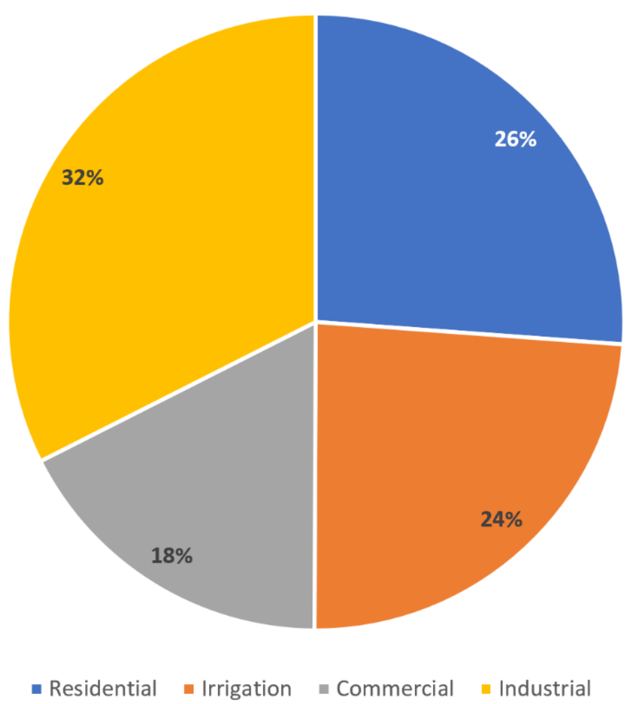
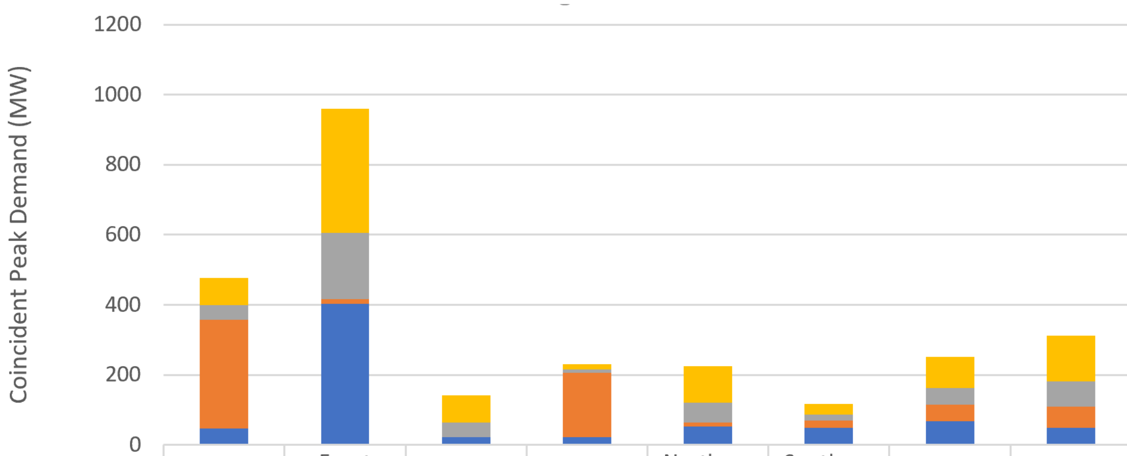


Figure 17. 2018 Coincident Peak Demand by Sector and Region

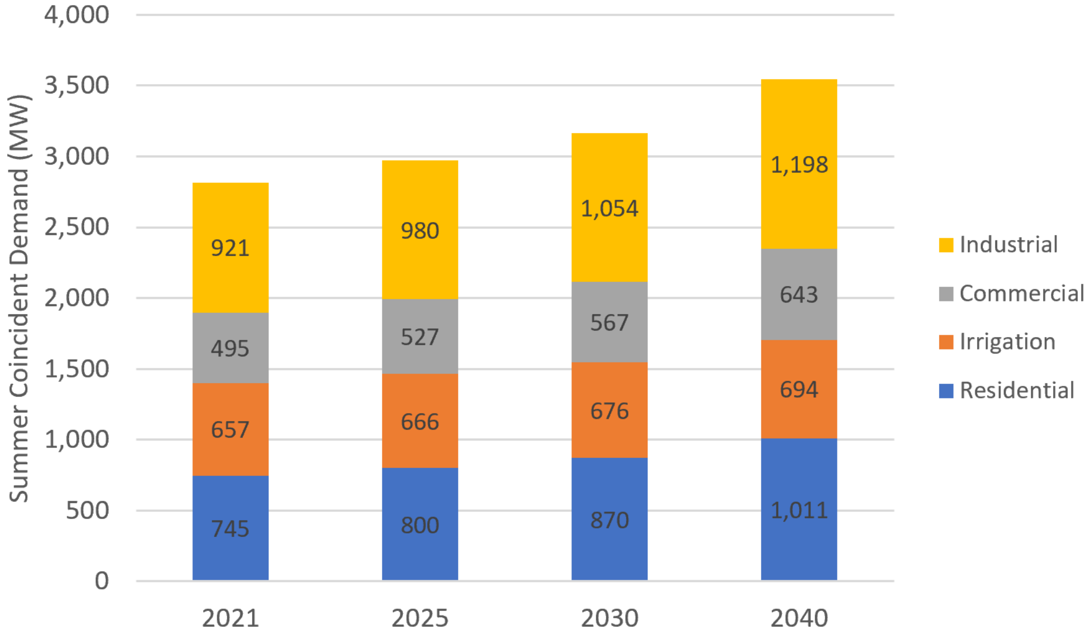


	Eastern Colorado	Front Range Colorado	Mountain Colorado	Nebraska	Northern New Mexico	Southern New Mexico	Western Colorado	Wyoming
Industrial	78	354	78	15	106	30	89	131
Commercial	42	190	42	8	57	16	48	71
Irrigation	309	14	0	185	11	22	46	61
Residential	47	402	21	22	52	48	68	49

Residential Irrigation Commercial Industrial

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

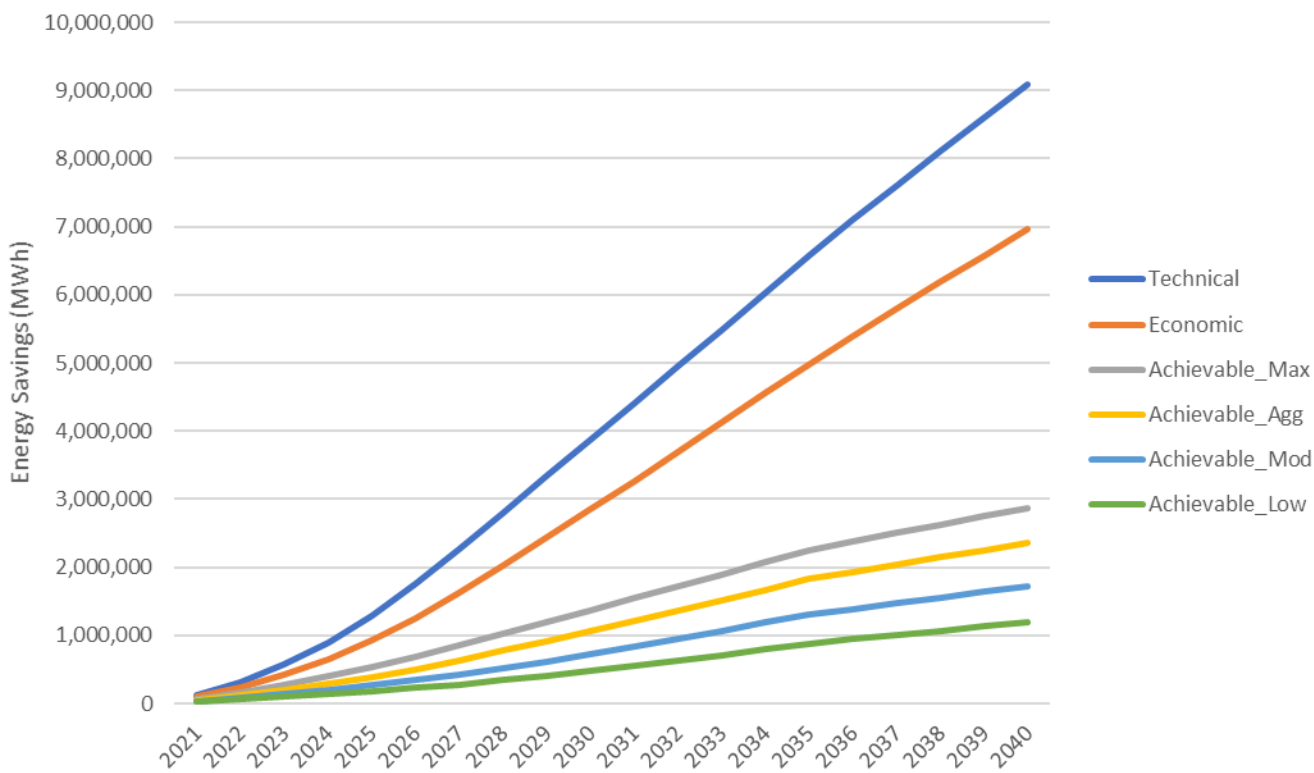


Table 11. shows the impacts of cumulative savings potential on Tri-State's baseline energy consumption forecast. The cumulative savings associated with the Achievable Moderate scenario would decrease Tri-State's baseline forecast consumption by approximately 0.25% in 2021. The reduction in baseline energy 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

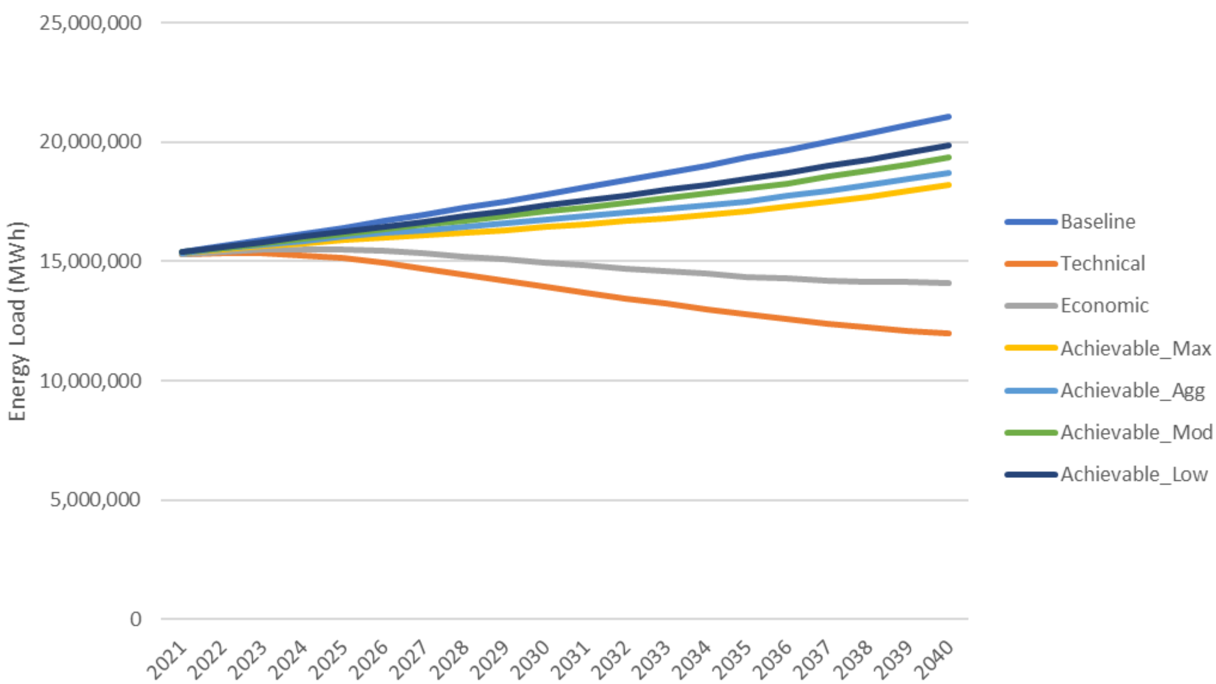
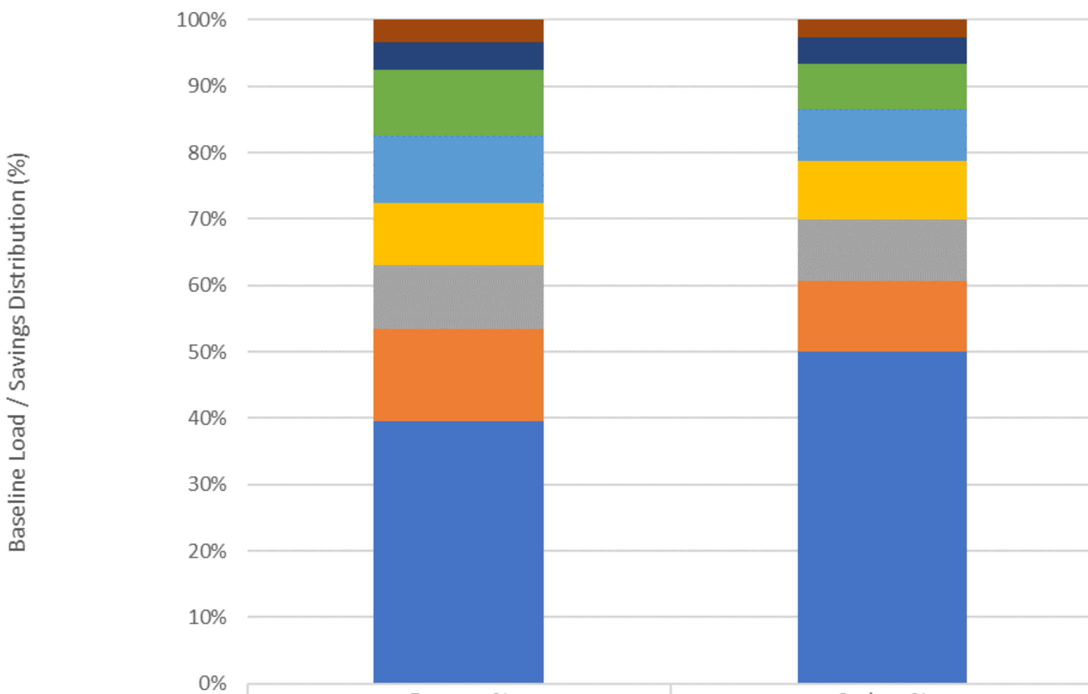


Figure 21 and Table 12 present energy savings potential by region. Front Range Colorado represents the largest share making up half the total. The other regions within Colorado account for nearly one quarter of the remaining savings potential. The two regions within New Mexico together comprise approximately 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



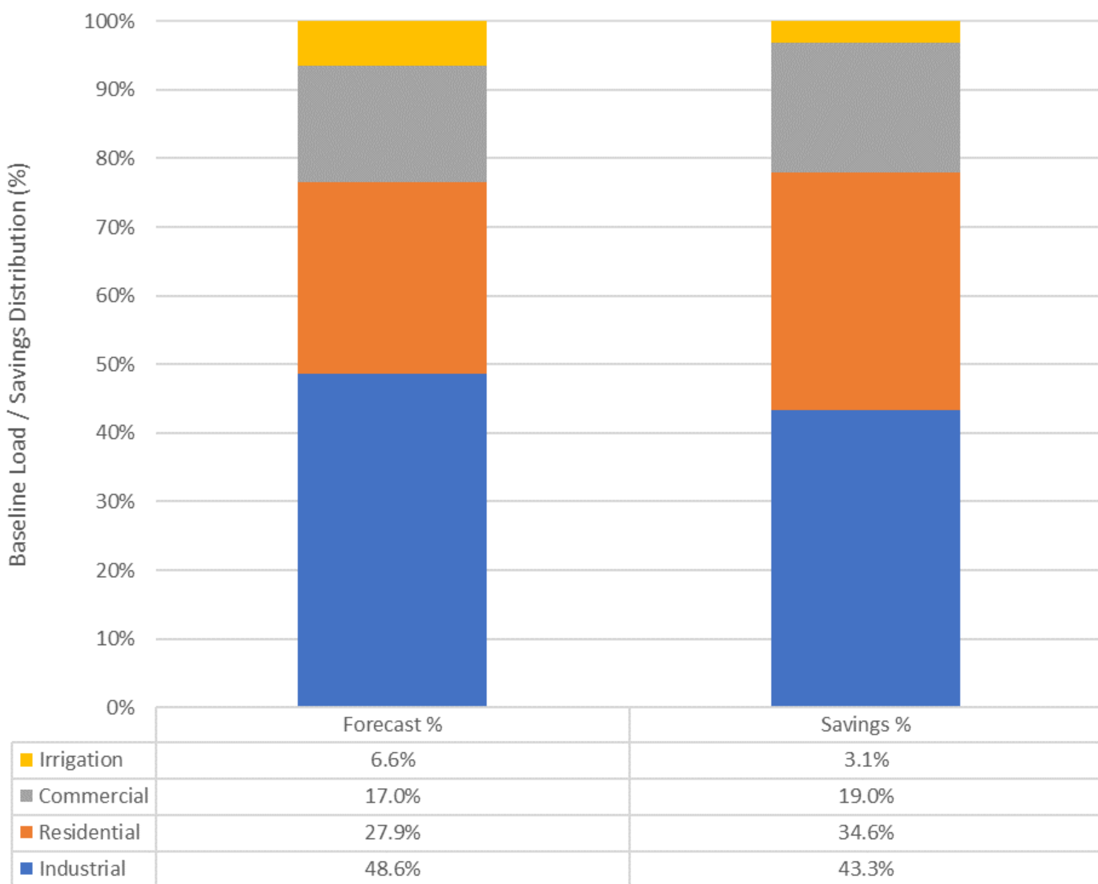
	Forecast %	Savings %
Nebraska	3.4%	2.7%
Southern New Mexico	4.1%	3.9%
Mountain Colorado	9.8%	6.8%
Eastern Colorado	10.2%	7.8%
Northern New Mexico	9.5%	8.8%
Western Colorado	9.6%	9.2%
Wyoming	13.9%	10.6%
Front Range Colorado	39.5%	50.0%

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.

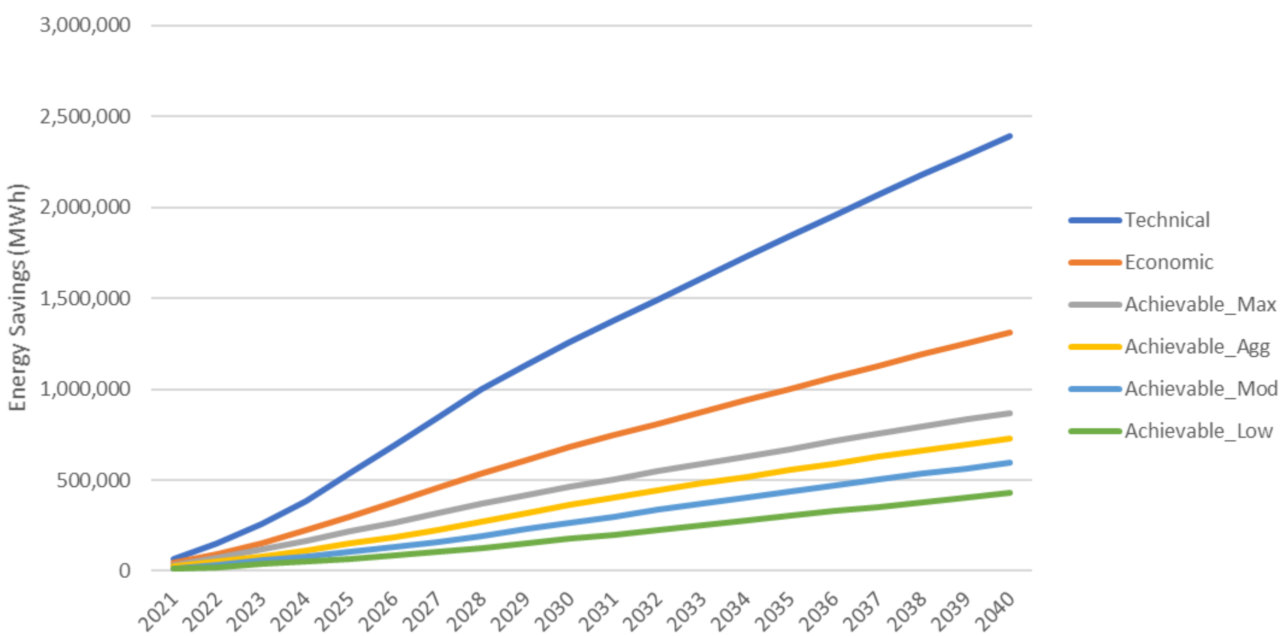
5.2. Detailed Results

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)

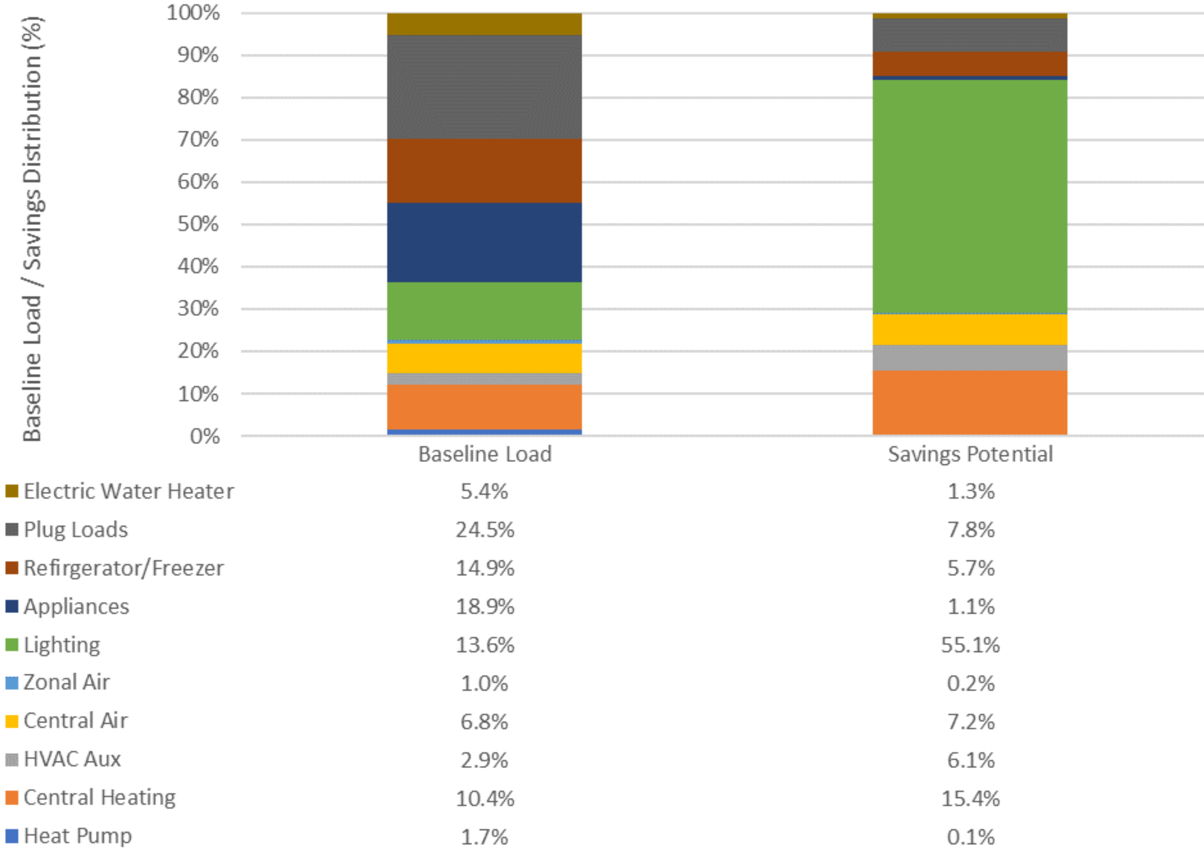


Table 17 presents cumulative residential demand savings by end-use by milestone year. High efficiency lighting is by far the greatest contributor to demand savings from residential energy efficiency measures producing 2,722 kW of cumulative demand savings through 2040. Additional measures with relatively 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

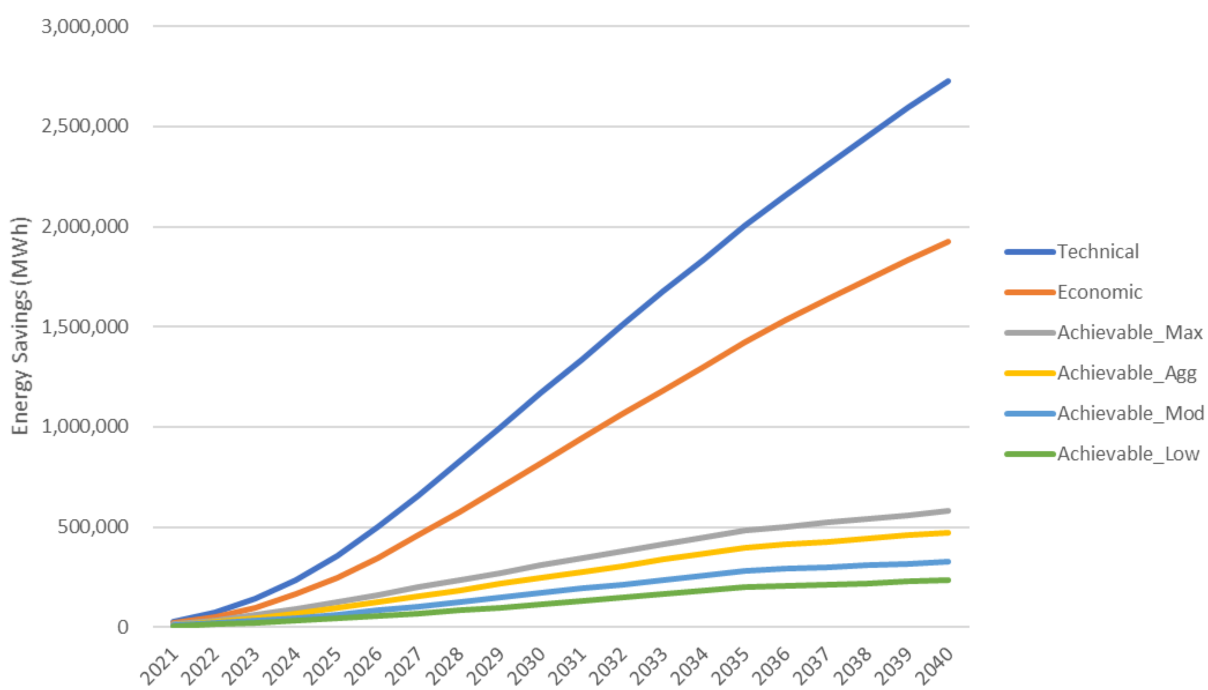
Table 19. presents cumulative savings potential for the commercial sector by scenario at various milestones in the analysis period and Figure 25 shows the growth in cumulative savings potential through 2040. The Achievable-Moderate scenario estimates 8.6 GWh of savings potential in 2021 rising to approximately 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



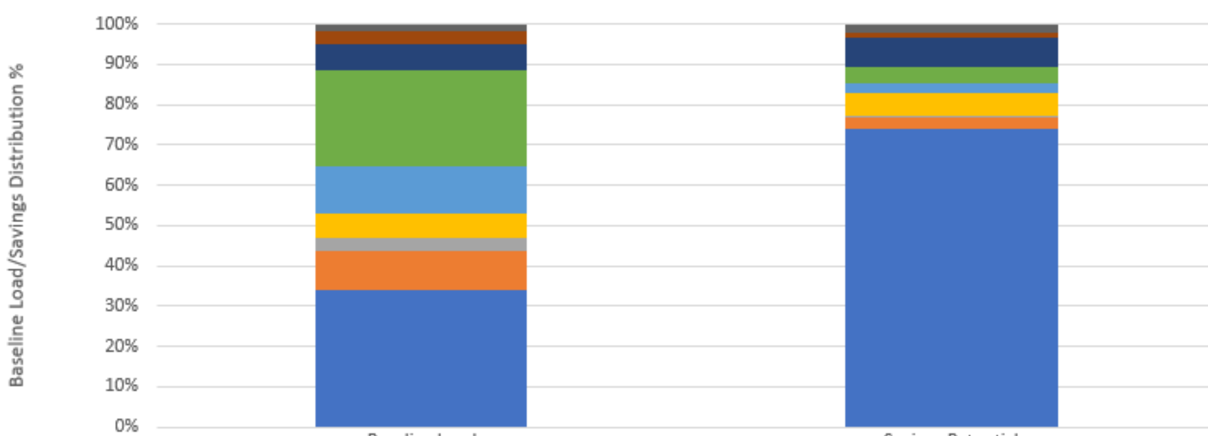
The cumulative commercial savings potential under the Achievable-Moderate scenario equates to a reduction of 0.32% of commercial baseline sales in 2021, a 2.25% reduction by 2025 and a 9.14% reduction by 2040 (see Table 20.). The Mesa Point Energy Team esimates a range in reduction of baseline energy 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)



	Baseline Load	Savings Potential
Water Heating	1.6%	2.1%
Cooking	3.2%	1.2%
Refrigeration	6.6%	7.5%
Plug Load	24.0%	3.9%
HVAC Auxiliary	11.5%	2.5%
Motors	6.3%	5.5%
Space Heating	3.2%	0.7%
Cooling	9.7%	2.6%
Lighting	33.8%	74.0%

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)

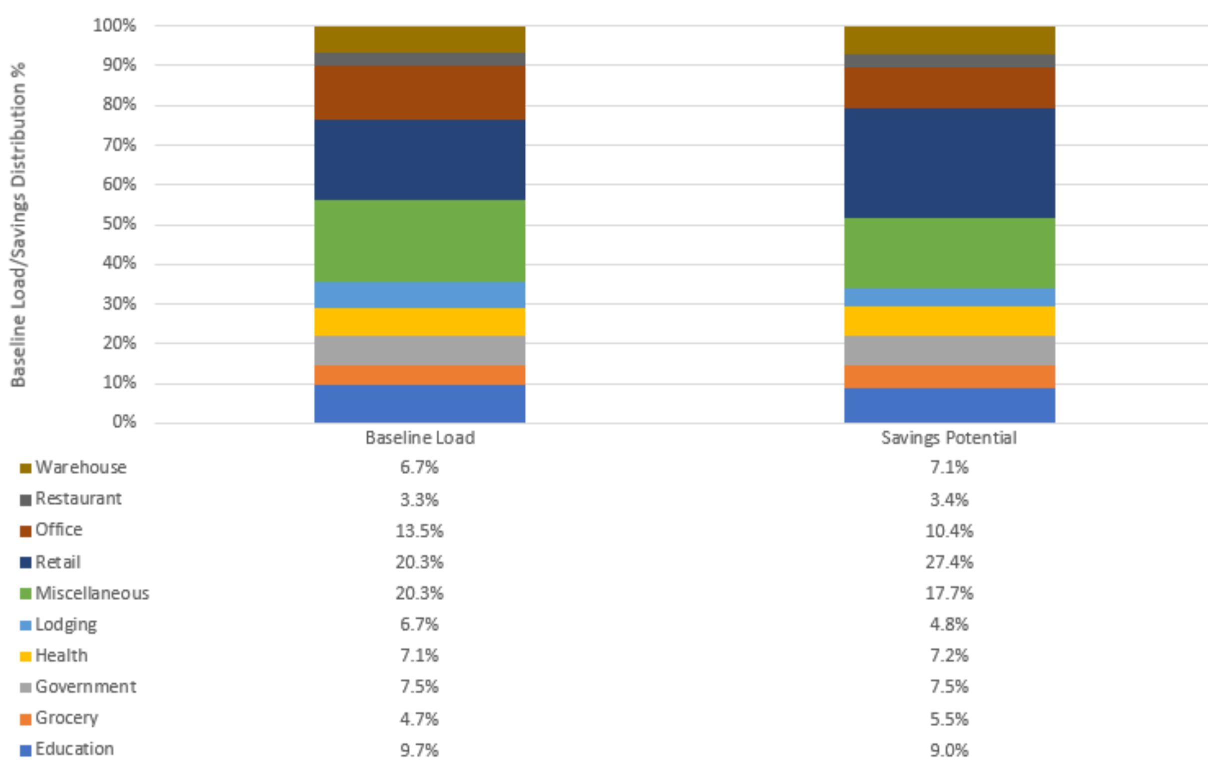


Table 22. summarizes cumulative commercial program cost metrics by milestone year. As shown, first-year program costs are approximately $1.4 million, rising to a 20-year average annual cost of roughly $4.1 millon. Acquisition costs start at $159/MWh during the first year of analysis and see a gradual 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.

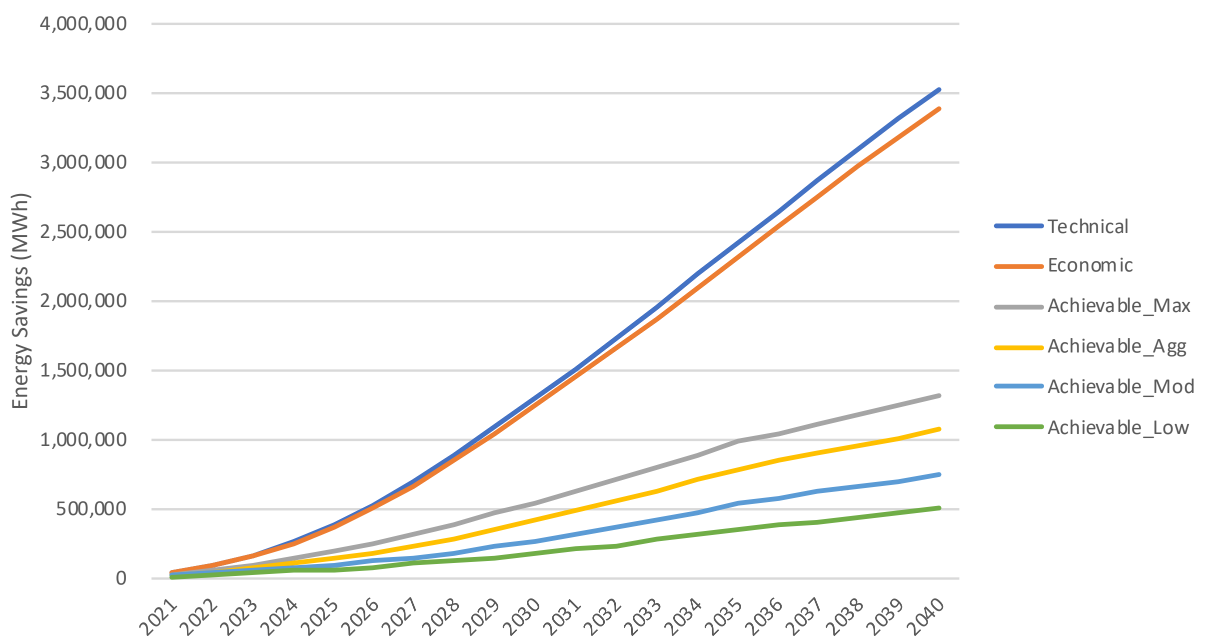
7.2. Detailed Results

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



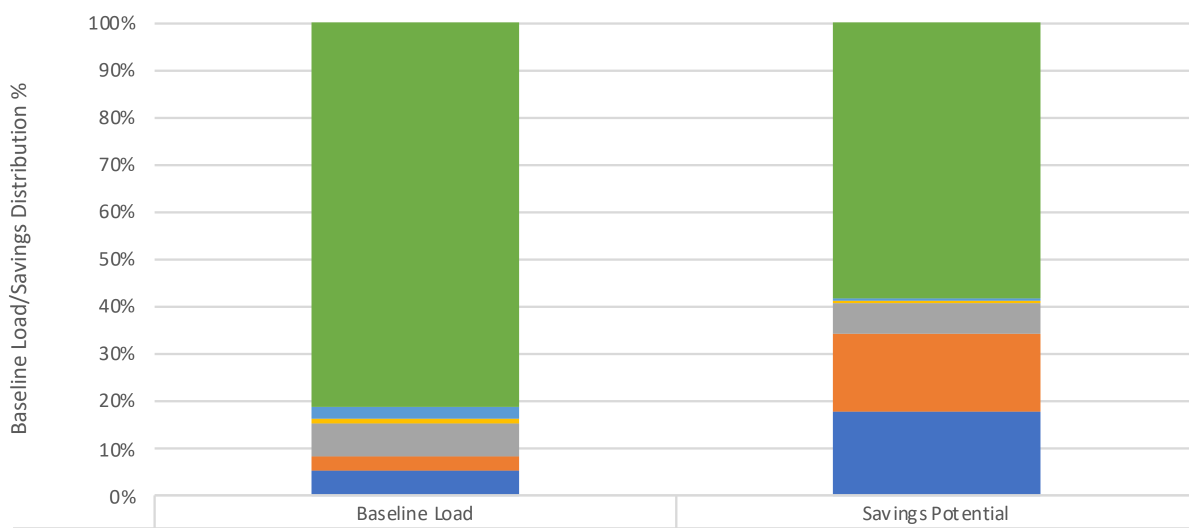
The cumulative industrial savings potential under the Achievable-Moderate scenario equates to a reduction of 0.21% of industrial baseline sales in 2021, a 1.24% reduction by 2025 and a 7.28% reduction by 2040 (see Table 24.). The analysis estimates a range in reduction of baseline energy sales for the 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

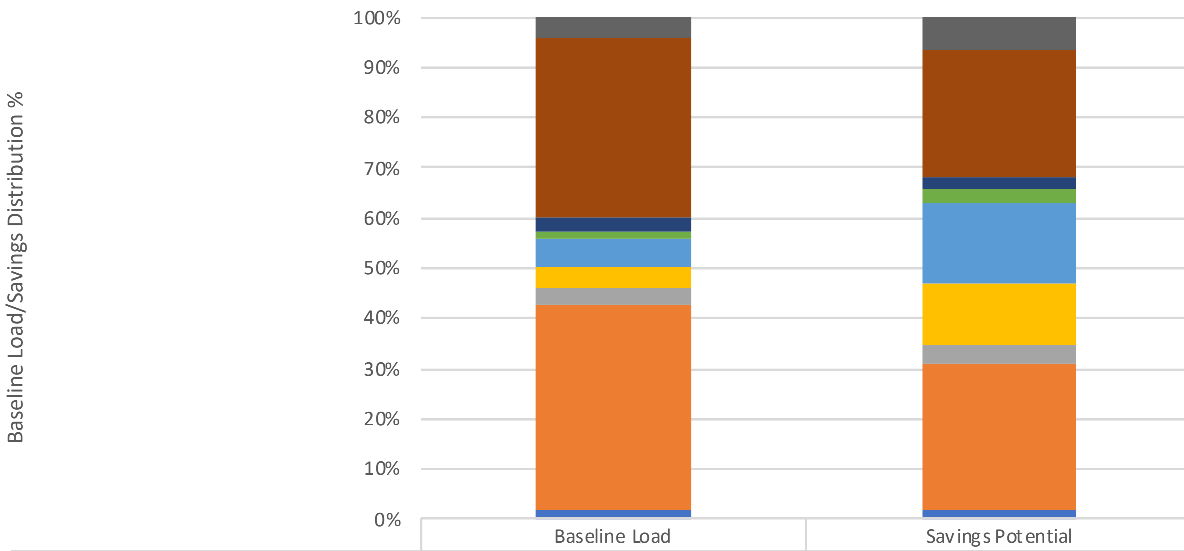
measures contribute nearly 6.6 MW of cumulative demand savings potential. Lighting efficiency measures have the potential to decrease demand by almost 1.3 MW and HVAC by nearly 1.7 MW.

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

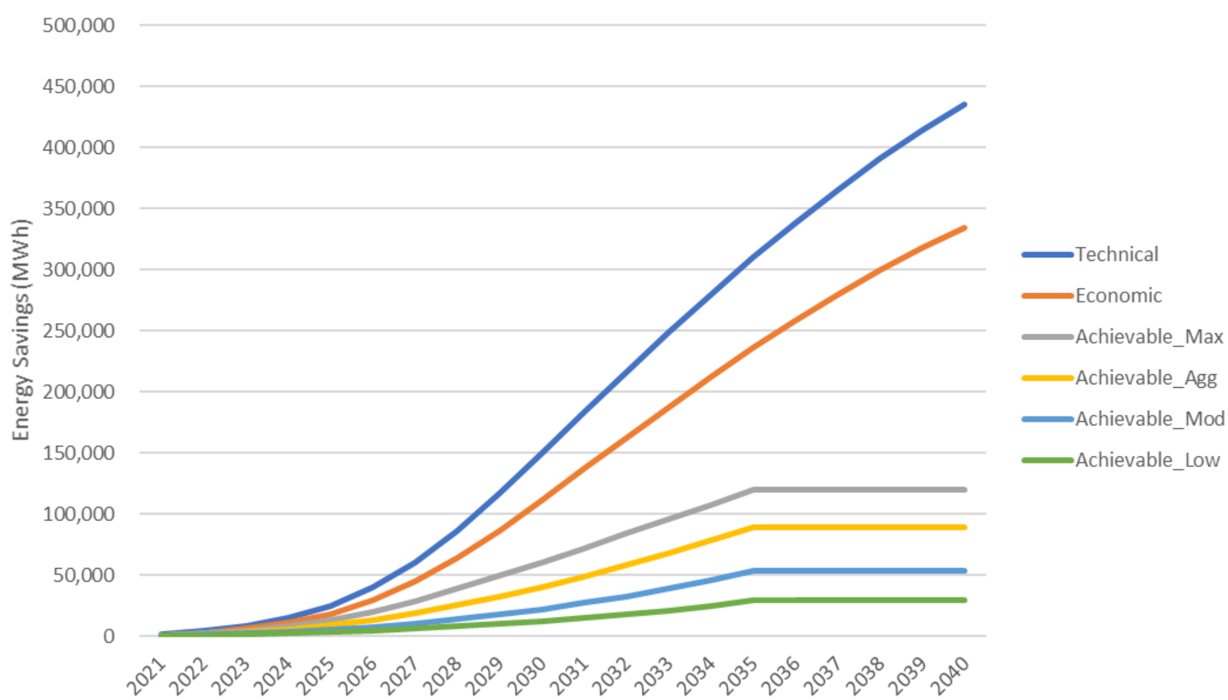


Table 28. shows the percentage impact of cumulative irrigation savings on the baseline forecast by scenario for each milestone year. Under the Achievable-Moderate scenario irrigation measures have the potential to reduce baseline load by nearly 4%. The maximum achievable scenario would more than double those savings to reduce baseline load by approximately 9%.

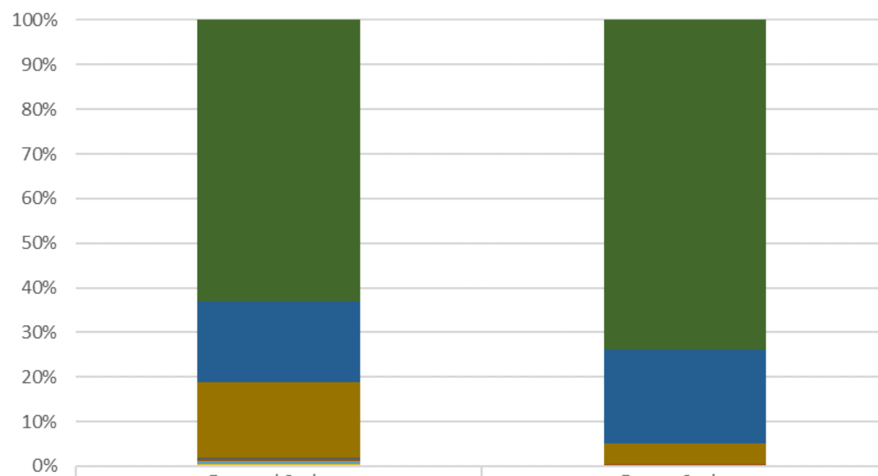
Eastern Colorado accounts for approximately half the irrigation savings potential, followed by Nebraska at approximately 30% of the total. Northern and Southern New Mexico together account for approximately 12% of total irrigation savings potential with the remaining regions making up a nominal share 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

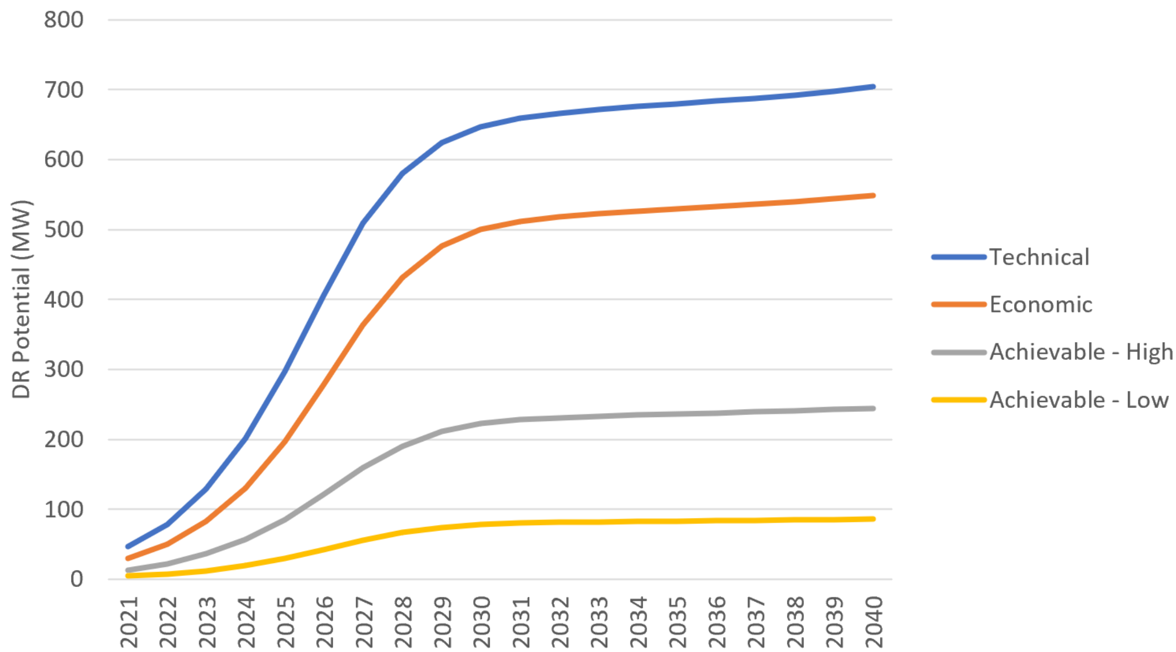


Table 31. shows the impacts of demand response potential relative to Tri-State's baseline demand forecast. The Achievable-High and -Low scenarios represent about 6.90% and 2.43% of forecasted coincident demand in 2040 respectively.

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)

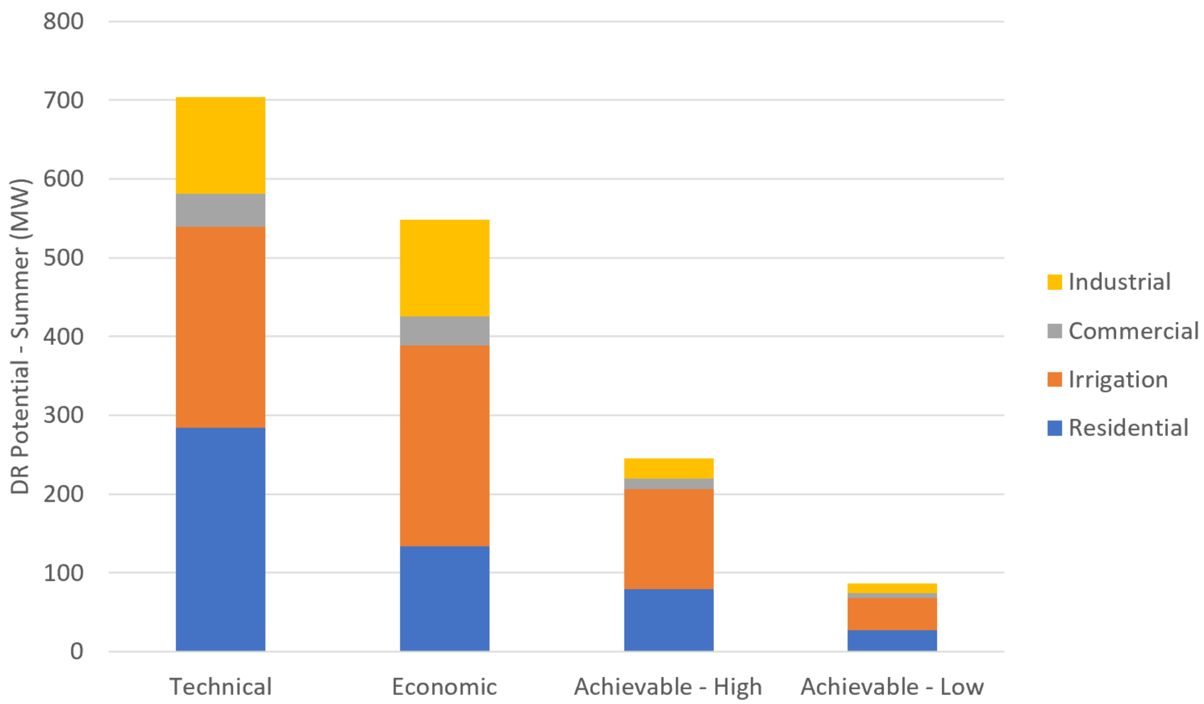
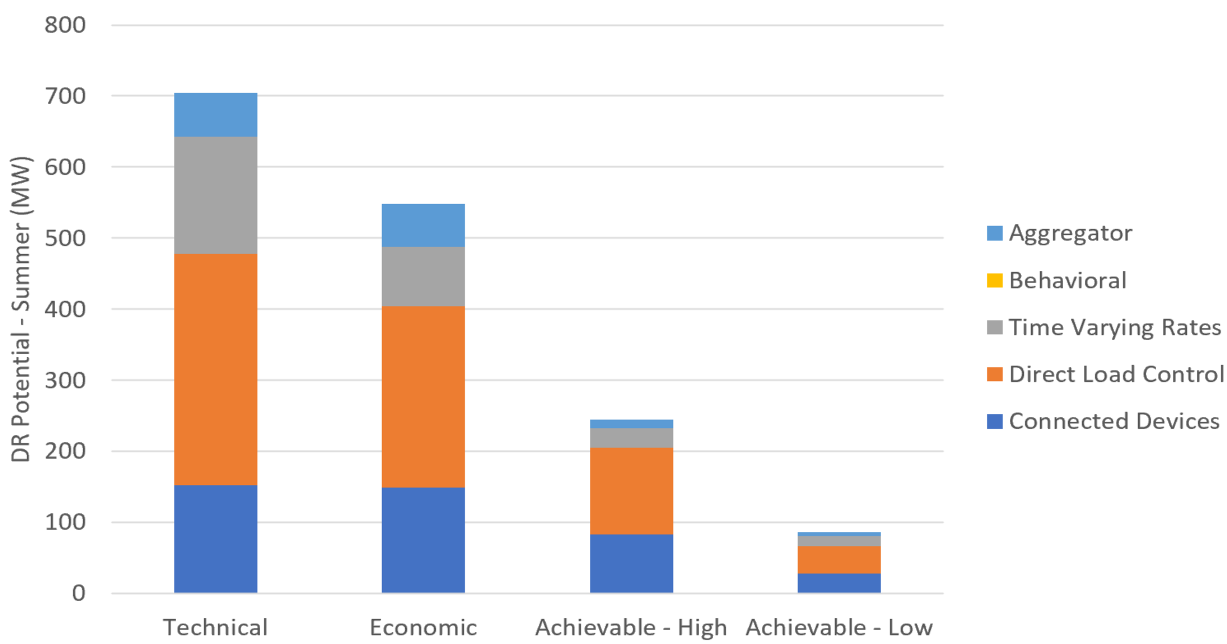


Figure 35. Portfolio Demand Response Potential by Program Type (2040)[16]



[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

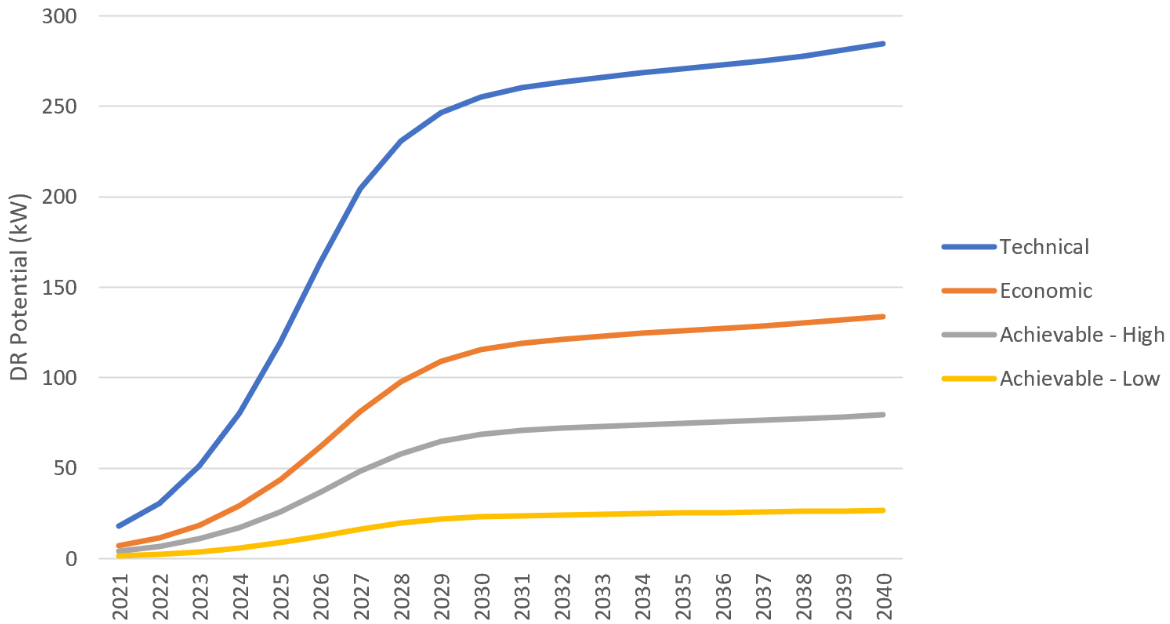
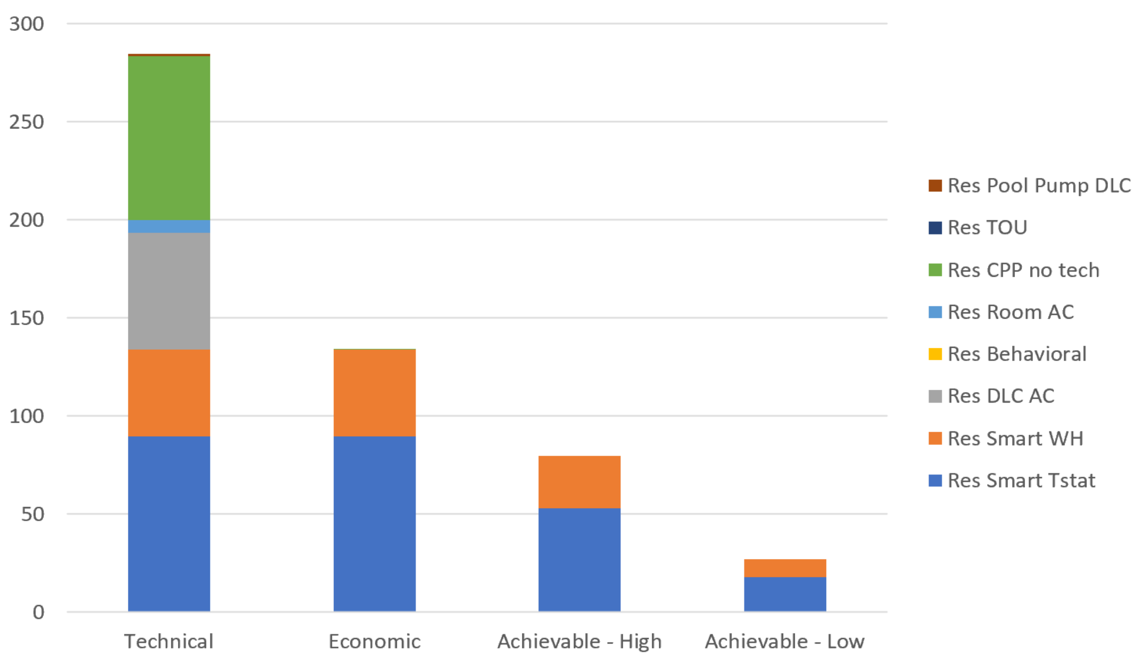


Figure 37. Residential Sector Demand Response Potential by Program (2040)



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

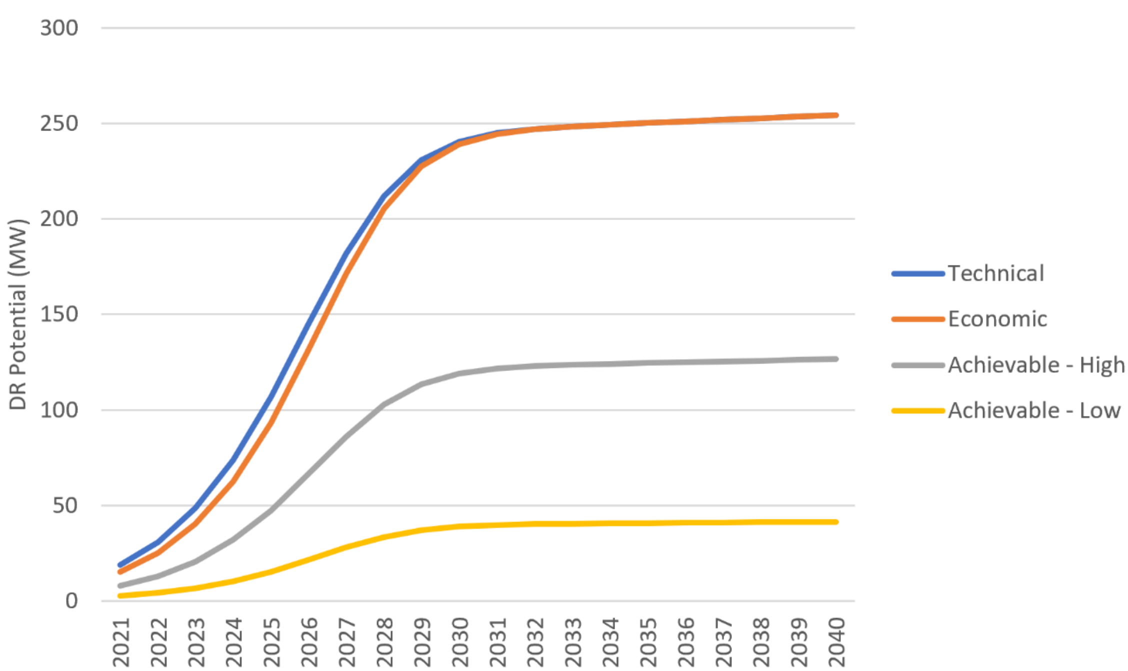
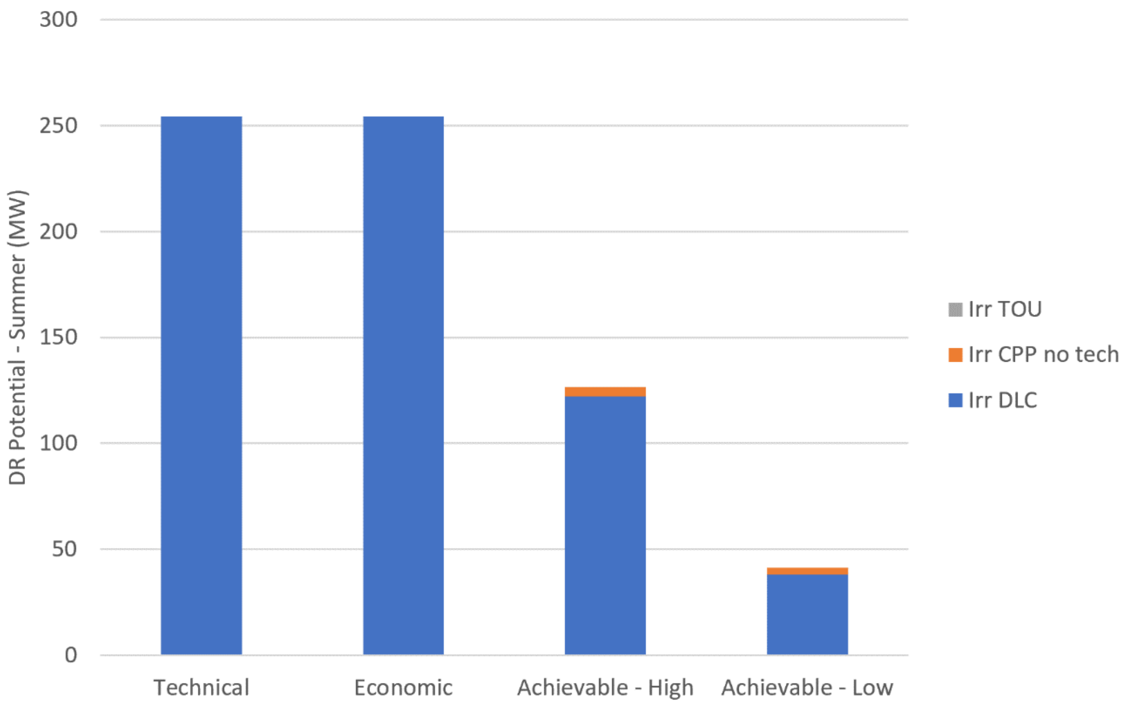


Figure 39. Irrigation Sector Demand Response Potential by Program (2040)



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

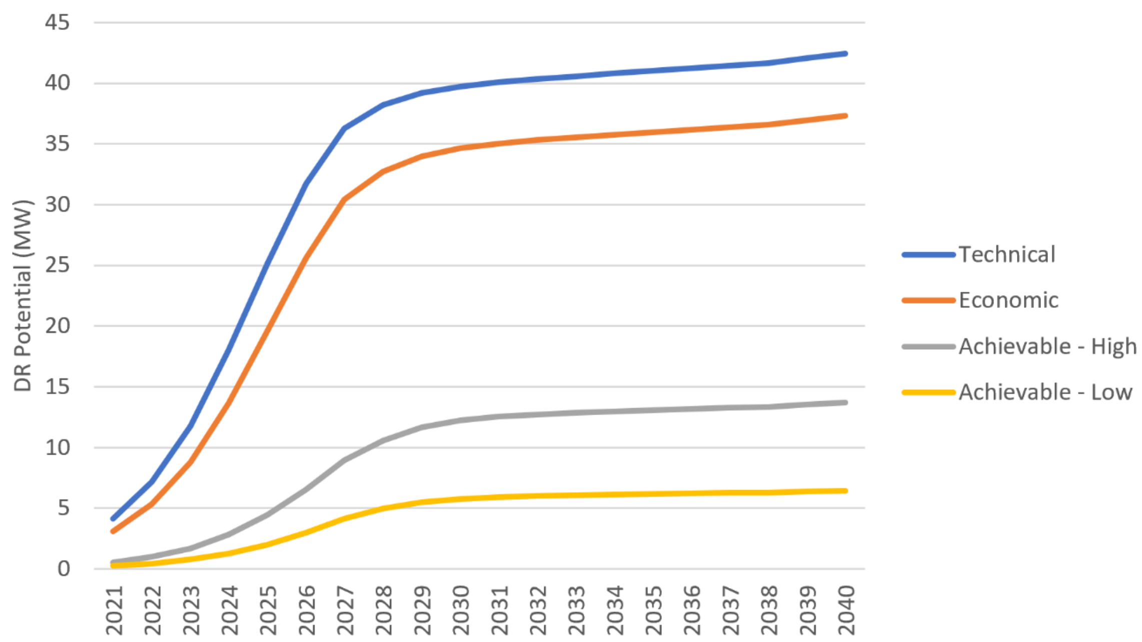
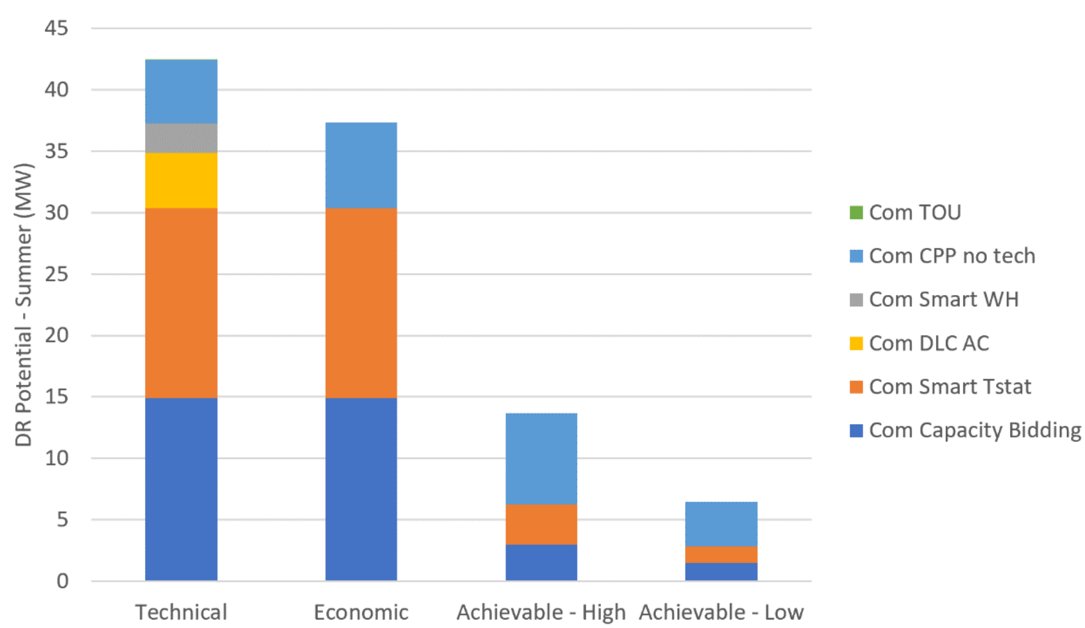


Figure 41. Commercial Sector Demand Response Potential by Program (2040)



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

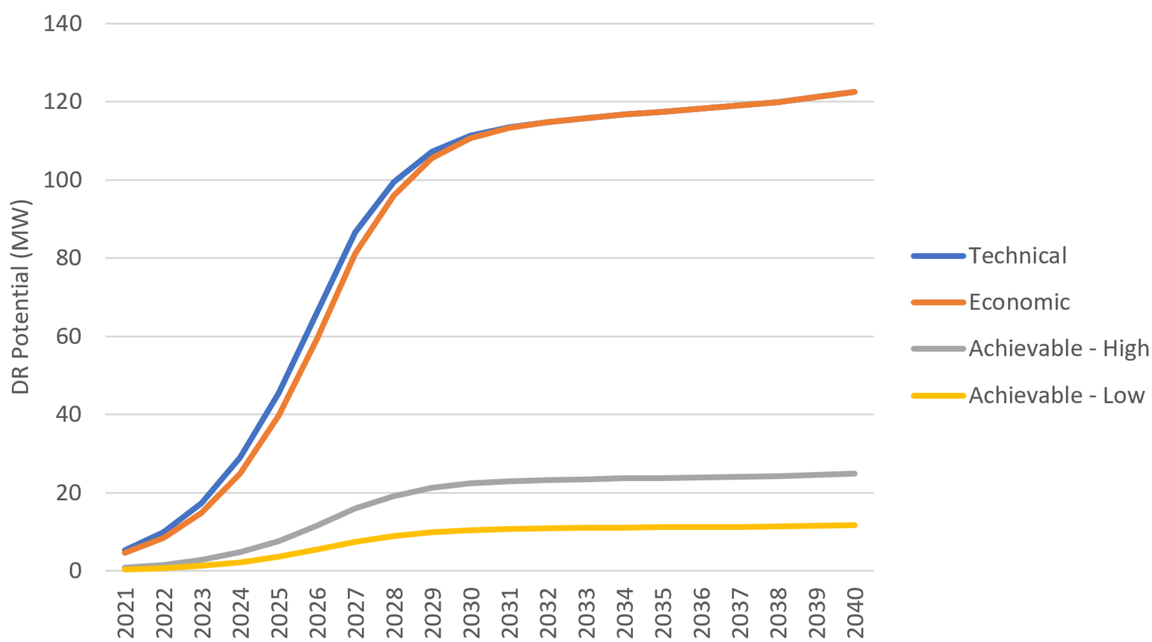
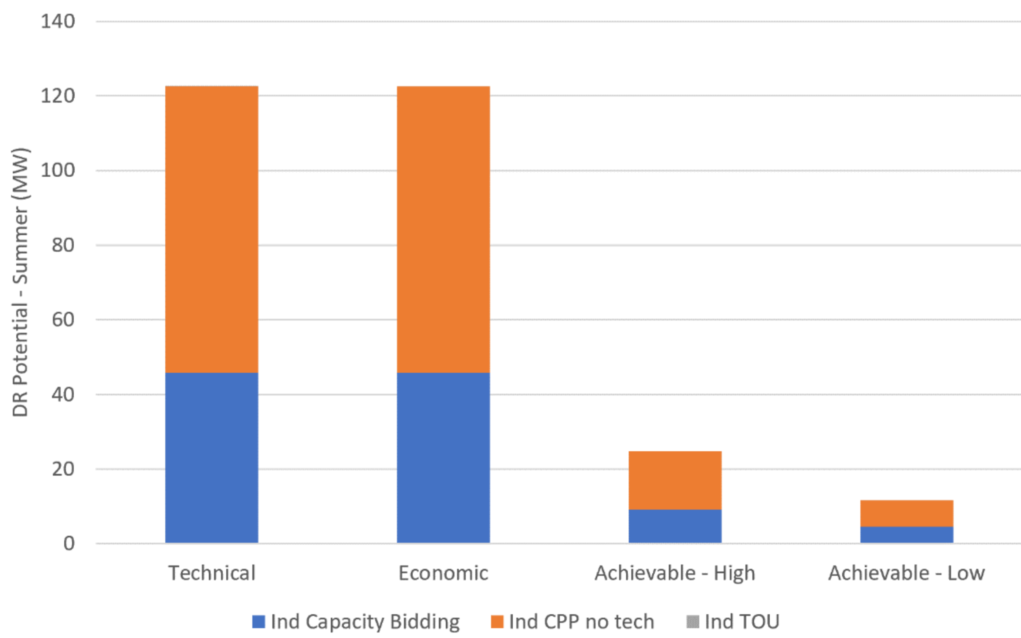


Figure 43. Industrial Sector Demand Response Potential by Program (2040)



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

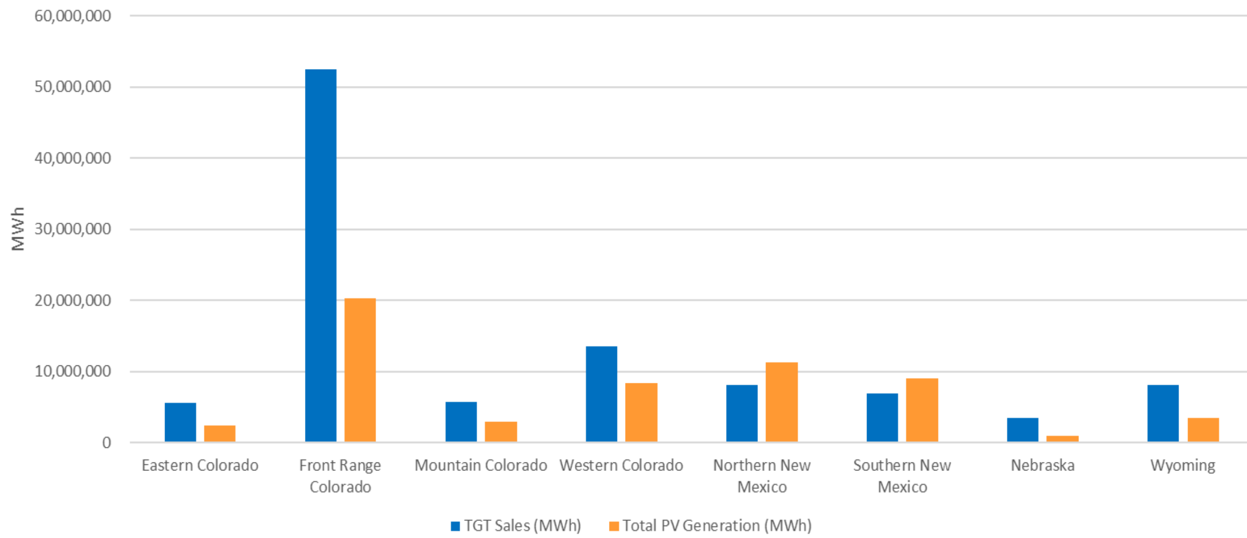
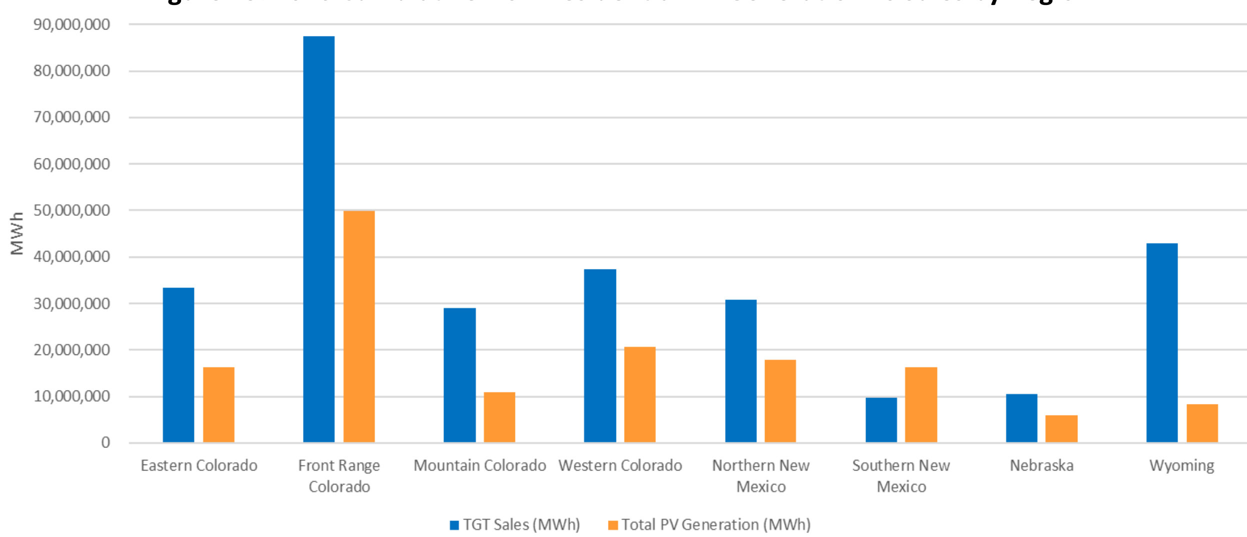


Figure 45. 2040 Cumulative Non-Residential PV Generation vs Sales by Region



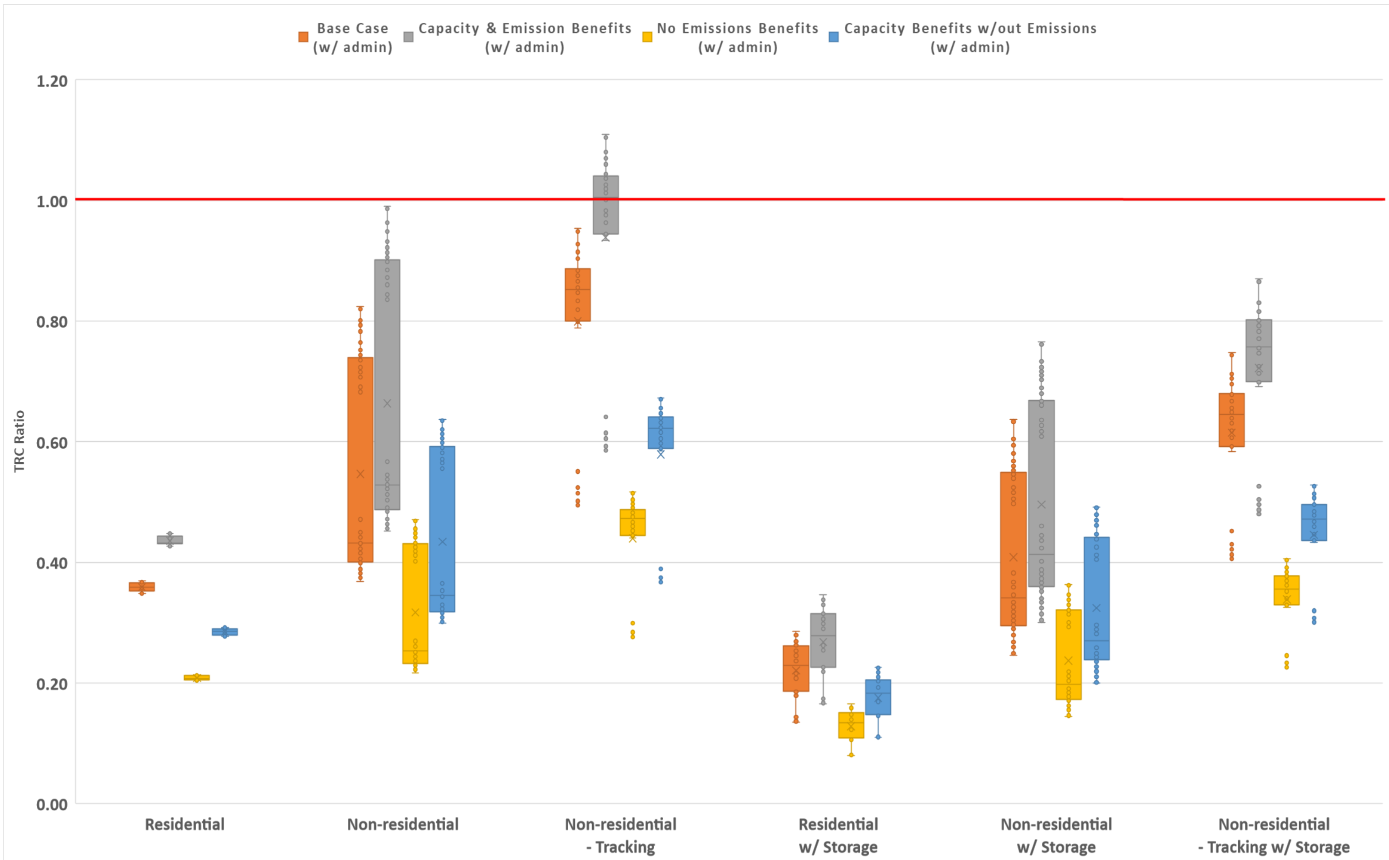
10.4. Economic and Achievable DER Potential Findings

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.

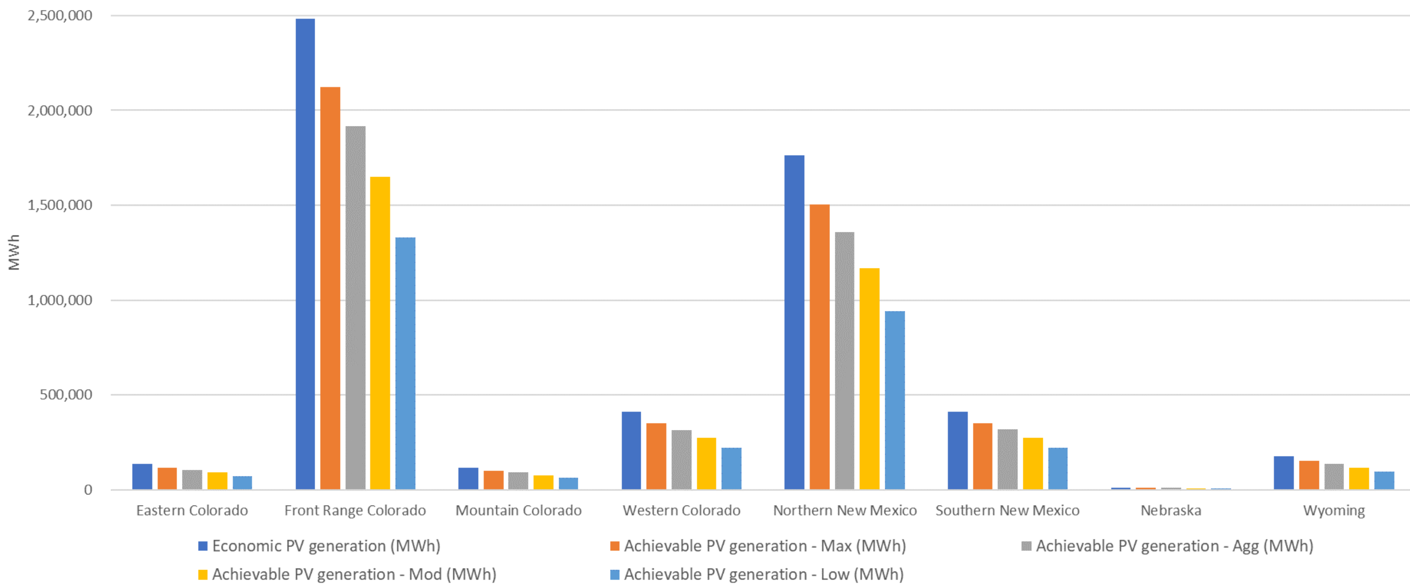
Figure 46. Solar PV TRC Ratios - Multiple Scenarios



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.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Tri-State	)	Order No. 202-25-14
Generation and Transmission	)	
Association, Platte River Power	)	
Authority, Salt River Project,	)	
PacifiCorp, and Xcel Energy	)	

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-50:
Insgold 2023 ERP Direct Testimony

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

PROCEEDING NO. 23A-____E

APPLICATION OF TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC. FOR APPROVAL OF ITS 2023 ELECTRIC RESOURCE PLAN

**DIRECT TESTIMONY AND ATTACHMENTS OF
BARRY W. INGOLD
ON BEHALF OF
TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.**

December 1, 2023

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ATTACHMENTS

BWI-1	Statement of Qualifications for Barry W. Ingold

I. <u>INTRODUCTION, QUALIFICATIONS, AND PURPOSE OF TESTIMONY</u>

Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A: My name is Barry W. Ingold. 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 Chief Operating Officer.

Q: ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS DOCKET?

A: I am testifying on behalf of Tri-State.

Q: HAVE YOU PREPARED A STATEMENT OF YOUR EXPERIENCE AND QUALIFICATIONS?

A: Yes. My Statement of Qualifications is attached to my testimony as **Attachment BWI-1**.

Q: PLEASE SUMMARIZE YOUR BACKGROUND AND EXPERIENCE IN THE ELECTRICITY UTILITY INDUSTRY.

A: I have 26 years of experience in the electric utility industry. In my present position, I am responsible for managing Tri-State's generation and transmission operations. This includes all capital budget and construction projects for Tri-State's generation and transmission facilities. Prior to joining Tri-State, I was an Application Control Engineer and Project Manager for Honeywell International, Inc., a global provider of control solutions. In addition to my years of industry experience, I served for thirteen years in the submarine force of the United States Navy. I then transitioned to the Navy Reserve where I served for an additional thirteen years, during which time I held command of five Navy Reserve Detachments. I attained the rank of Captain prior to retiring from the United States Navy. I hold a Bachelor's degree in Marine Engineering and Marine Transportation from the United States Merchant Marine Academy, a Master's degree in Mechanical Engineering from the Naval Postgraduate School, and a Master's degree in Business Administration from Arizona State University.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A: My Direct Testimony addresses certain technical and operational assumptions regarding Tri-State's owned and contracted thermal (coal and natural gas) resources relied upon as inputs to the 2023 Electric Resource Plan ("ERP"). I also address assumptions and analysis regarding the potential for new or expanded owned or contracted thermal resources during the resource acquisition period ("RAP").

Q. ARE YOU SPONSORING ANY ATTACHMENTS AS PART OF YOUR TESTIMONY?

A. Yes, as part of my Direct Testimony, I am sponsoring the following attachments:

- Attachment BWI-1: Statement of Qualifications for Barry W. Ingold

II. <u>EXISTING COAL RESOURCES</u>

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section of my Direct Testimony, I identify and describe Tri-State's current, existing coal-fired fleet, including forecasted operations and emissions reductions, during the RAP.

Q: PLEASE BRIEFLY DESCRIBE THE CURRENT COAL-FIRED GENERATION

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RESOURCES IN TRI-STATE'S GENERATION FLEET.

A. Tri-State maintains a stake in three coal-fired generation facilities across its system footprint. These include:

- Craig Station (Units 1, 2, and 3), located in Colorado, with net generating capacity of 427 MW, 410 MW,[1] and 448 MW, respectively. Tri-State is the operator of Craig Station.
- Laramie River Station ("LRS"),[2] located in Wyoming, with net generating capacity of 1700 MW. LRS, and associated transmission, make-up the Missouri Basin Power Project ("MBPP"). Basin Electric Power Cooperative is the operator of the MBPP.
- Springerville Unit 3 ("SPV 3"), located in Arizona (primarily serving Tri-State's New Mexico load), has a net generating capacity of 419 MW. Tucson Electric Power Company is the operator of SPV 3.

Q. WHERE DOES TRI-STATE SECURE ITS COAL SUPPLY FOR THESE GENERATION RESOURCES?

A. Coal is supplied to Tri-State's fleet as follows:

- Craig Station: Colowyo Mine supplies coal for Tri-State and Public Service Company of Colorado's ("Public Service") portion of Craig Station. Trapper Mine supplies coal for the other three Yampa Partners'[3] portion of Craig

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[1] Tri-State's net share of Craig 1 is 102 MW and Craig 2 is 98MW.
[2] LRS is a jointly owned unit under the Missouri Basin Power Project ("MBPP"). Tri-State is an MBPP participant with a 28.5 percent (484 MW) share and receives power from LRS 2 and LRS 3 due to their location in the western interconnection.
[3] Platte River Power Authority ("PRPA"), Salt River Project ("SRP"), and PacifiCorp.

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Station. Unit 3 uses coal supply from only Colowyo, while Units 1 and 2 use a coal supply split from Trapper and Colowyo, with Trapper supplying a majority of the fuel for those two units.

- LRS: The MBPP procures and delivers coal from the Powder River Basin on behalf of the MBPP participants.
- SPV 3: Tri-State contracts with Peabody COALSALES, LLC, and the BNSF Railway Company to procure and deliver coal from the Powder River Basin to SPV 3.

The latest coal price forecast is a financial input to the 2023 ERP Phase I modeling and is identified in **Attachment** LKT-7 ~~**B** of the ERP Report (**Attachment LKT-1**).~~

Q: HOW ARE THESE UNITS FORECASTED TO OPERATE DURING THE RAP?

A: As further discussed within the Direct Testimony of Ms. Tiffin, Craig Station will conclude operations in 2028; and, if New ERA funding is received as requested, SPV 3 will retire in 2031, subject to reaching agreement with the applicable parties. LRS will continue its operations as it has previously, subject to applicable federal and state regulations.

Q: PLEASE DESCRIBE TRI-STATE'S GOALS AND ACHIEVEMENTS RELATED TO EMISSIONS REDUCTIONS FROM THE USE OF COAL-FIRED GENERATION.

A: Under Tri-State's Responsible Energy Plan ("REP"), we eliminated carbon emissions from Tri-State-owned coal generation in New Mexico in 2020. In Colorado, by 2030, we are targeting a 100 percent reduction in carbon emissions from Tri-State-owned coal generation. Additionally, by 2030, our goal is for 70 percent of the electricity our Members use system-wide to come from clean sources.

Additionally, under the 2020 ERP Phase I Settlement Agreement in Proceeding No. 20A-0528E, Tri-State committed that going forward, it will operate its system in a manner that achieves an 80 percent reduction in greenhouse gas ("GHG") emissions related to Tri-State's wholesale sales of electricity in Colorado in 2030.[4] As described by Ms. Tiffin in her Direct Testimony, all of the 2023 ERP Phase I scenarios were modeled in alignment with these REP and ERP commitments, with any modifications identified in **Attachment** LKT-10 ~~**B-3** of the ERP Report (**Attachment LKT-1**).~~

Emissions and water use rates for each generator are identified in **Attachment** LKT-7 ~~**B** of the ERP Report (**Attachment LKT-1**).~~

a. <u>Craig Station</u>

Q: DOES TRI-STATE'S COAL-FIRED GENERATION FACILITY LOCATED IN COLORADO HAVE A FIRM RETIREMENT DATE?

A: Yes. In January 2020, Tri-State voluntarily announced the planned retirement of all of Craig Station, including all three units, by 2030. The Craig Station units' closure dates are also identified in Colorado Regulation No. 23 Regional Haze Limits that were adopted by the Colorado Air Quality Control Commission ("AQCC") and made effective by publication in the Colorado Register on February

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[4] 2020 ERP Phase I Settlement Agreement, Section 3.3.5. states: "Tri-State also 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, an eighty percent (80%) reduction in GHG emissions related to Tri-State's wholesale sales of electricity in Colorado in calendar-year 2030 ("the 2030 Emissions Reduction").

14, 2021, as discussed further in Mr. Berger's Direct Testimony. Within Decision No. C23-0437 in Proceeding No. 20A-0528E, the Commission ordered Tri-State to evaluate alternative retirement dates for Craig 3 within the 2023 Phase I ERP modeling assumptions and practices to analyze the benefits and costs associated with various retirement dates, including economically optimal retirement dates as part of its Direct Case.[5] Pursuant to Decision No. C23-0437, Tri-State has reflected this directive within the 2023 ERP Phase I modeling as further outlined within the Direct Testimony of Lisa K. Tiffin and in the scenario assumptions identified in **Attachment** ~~**B-3** of the ERP Report (**Attachment LKT-1**).~~ LKT-10 The retirement dates considered for Craig Unit 3 provide time for Tri-State to work with the State of Colorado to complete and begin to implement a transition plan for those employees and communities impacted by the closure of Craig Station.

Q: WHAT IS THE STATUS OF TRI-STATE'S EFFORTS IN ENSURING A JUST TRANSITION FOR THE CRAIG COMMUNITY?

A. There are two elements to the Just Transition effort. The first being a Workforce Transition Plan, which was submitted to the Colorado Office of Just Transition ("OJT") in December 2022, pursuant to the 2020 ERP Phase I Settlement Agreement, Section 3.12.1. As part of the workforce transition, Tri-State also executed a Letter of Agreement ("LOA") with IBEW Local 111 that outlines the manner in which employees will be affected as part of the closure of Craig Station. The second component of the just transition is community assistance. Tri-State's

[5] Decision No. C23-0437, at ¶ 77 (Proceeding No. 20A-0528E).

community assistance approach will be informed by the Informational Community Assistance Plan ("ICAP") under development by Tri-State, OJT, the City of Craig, Moffat County, the Colorado Energy Office, and the Office of the Utility Consumer Advocate, led by a third-party facilitator. The ICAP is planned to be complete in June 2024; it will be filed on an informational basis in the 2020 ERP proceeding, as identified in the 2020 ERP Settlement Agreement. Following ICAP completion, Tri-State will review the areas of assistance of greatest interest to the community identified in the ICAP, determine a financially feasible approach to community assistance, and make a recommendation for Tri-State Board approval by Q1 2025. These Just Transition plans are further discussed in the Direct Testimony of Mr. Orvis.

Q: WHAT APPROACH IS TRI-STATE TAKING TO CAPITAL AND OPERATIONAL INVESTMENTS FOR CRAIG STATION OVER THE REMAINING LIFE OF THE PLANT?

A: Tri-State's investments in Craig Station are being appropriately limited to only actions necessary for ensuring safe operations and regulatory compliance, given the impending retirement of these units.

b. <u>LRS</u>

Q: PLEASE IDENTIFY THE KEY OPERATIONAL CONSIDERATIONS FOR LRS IN THE 2023 ERP.

A: Tri-State is a participant in the MBPP, with a 28.5 percent (484 MW) share. Tri-State receives a portion of LRS generation and transmission capacity through its MBPP contract. Tri-State has a contractual obligation to pay its share of LRS

MBPP costs through the plant's full useful life. Tri-State does not have unilateral decision authority regarding LRS operations.

c. <u>SPV 3</u>

Q: IDENTIFY THE KEY OPERATIONAL CONSIDERATIONS FOR SPV 3 IN THE 2023 ERP.

A: First, Tri-State is not a joint owner of the Springerville plant and is not the plant operator. Tucson Electric Power ("TEP") is the facility operator and owner of SPV Units 1 and 2 and Salt River Project ("SRP") is the owner of SPV 4. Second, Tri-State is the majority equity owner of the partnership that indirectly owns SPV 3; and one hundred percent of SPV 3 is leased by Tri-State. Third, Tri-State supplies 100 MW of unit contingent capacity from SPV 3 to a third-party offtaker, SRP, under a power purchase agreement ("PPA") that extends through summer 2036. Fourth, certain common facilities and operational and maintenance costs are shared across the four SPV units. TEP has indicated Unit 1 will retire at the end of 2027 and Unit 2 will retire after the summer of 2032.[6] SPV 3 operational and financial assumptions reflected in 2023 ERP Phase I modeling are provided in **Attachment** LKT-7 ~~**B** of the ERP Report (**LKT-1**).~~

Q: HAS TRI-STATE INFORMED SRP, TEP, AND THE OTHER EQUITY OWNER OF THE IRA SCENARIO RESULTS FOR SPV 3?

A: Yes. Tri-State has informed these parties of the 2031 retirement date for SPV 3, subject to New ERA funding and reaching agreement with the applicable parties.

[6] https://www.tep.com/wp-content/uploads/TEP-2020-Integrated-Resource-Plan-Lo-Res.pdf (page 93).

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Ms. Tiffin's Direct Testimony further discusses Tri-State's approach to implementation of the IRA Scenario resource plan.

III. <u>EXISTING NATURAL GAS RESOURCES</u>

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section of my Direct Testimony, I identify and describe both Tri-State's current natural gas resources, as well as a new gas unit addition planned during the RAP.

Q: PLEASE IDENTIFY AND BRIEFLY DESCRIBE THE CURRENT NATURAL GAS GENERATION RESOURCES IN TRI-STATE'S GENERATION FLEET.

A: Tri-State fully owns and operates four natural gas generation resources across its system footprint in Colorado and New Mexico. These resources are identified in **Attachment** LKT-17 ~~**C-3** of the ERP Report (**Attachment LKT-1**)~~ and include both combined and simple cycle generating units. Specifically, the fleet includes simple cycle units that have dual-fuel capabilities.

Q: PLEASE DESCRIBE THE RELIABILITY BENEFITS OF OPERATING NATURAL GAS FACILITIES IN CONCERT WITH THE INCREASING DEPLOYMENT OF RENEWABLE RESOURCES.

A: As fully dispatchable resources, gas resources allow for response to gradual or abrupt changes in energy supply, within unit ramping characteristics, that may arise from the increasing deployment of renewables, which assists in maintaining system balance.

IV. <u>NEW COMBINED CYCLE NATURAL GAS PLANT</u>

Q: WHAT DOES THE 2023 ERP PHASE I IRA SCENARIO INDICATE REGARDING

THE NEED FOR AN ADDITIONAL GAS RESOURCE?

A: The IRA Scenario, which is Tri-State's preferred resource plan, selects a 290 MW natural gas combined cycle ("NGCC") resource in 2028 located in electrically western Colorado.[7] The IRA Scenario also adds carbon capture and sequestration ("CCS") to the combined cycle resource in 2031. The technical, operational, and financial assumptions modeled for the generic natural gas with CCS (NGCC with CCS) facility can be found in **Attachment** LKT-16 ~~**C-2** of the ERP Report (**Attachment LKT-1**).~~

Q: WHAT KEY BENEFITS DOES A COMBINED CYCLE GAS RESOURCE ADD TO TRI-STATE'S GENERATION FLEET?

A: As described above, natural gas resources provide a complementary and necessary reliability backbone for meeting load needs with an increasing amount of intermittent renewable resources. As identified in the ERP Report (**Attachment LKT-1**), 64 percent of Tri-State's system energy needs are forecasted to be served by renewable energy in 2030, even with the addition of this new gas unit. Also, firm capacity to deliver energy when called upon is critical to maintaining reliability across the Tri-State system, especially during prolonged periods of low or no solar and wind production.

Q: DID TRI-STATE EXPLORE ALTERNATIVE NATURAL GAS EXPANSION SOLUTIONS INSTEAD OF A NEW RESOURCE ADDITION?

A: Yes. Tri-State evaluated two alternative options for obtaining the additional natural

[7] See planning region definitions in the ERP Report (LKT-1).

gas capacity needed to maintain system reliability: (1) contracting for the capacity through near-term power purchase agreements ("PPAs"), and/or (2) expanding the capacity of Tri-State's existing natural gas generation facilities. Ms. Hunter's Direct Testimony addresses the first alternative and I address the second, along with Mr. Berger.

Q: COULD TRI-STATE EXPAND THE CAPACITY OF ITS EXISTING NATURAL GAS GENERATORS TO MEET THE NEED FOR A NATURAL GAS RESOURCE DURING THE RAP?

A: No. Tri-State assessed each of its four existing natural gas generating facilities and its Burlington oil-fired generation resource for the potential for expansion of capacity from these existing generators. The following describes the results of that assessment:

- J.M. Shafer and Knutson: These units are located in an ozone nonattainment area. Turbine upgrades would be difficult due to environmental permit limitations and expensive due to the capital expenditures associated with the locations. These challenges are further described in Mr. Berger's Direct Testimony.
- Pyramid: Without firm gas transport for the facility, Tri-State must purchase delivered gas, which is likely to make capacity expansion at this facility less financially viable. Additionally, the location of Pyramid relative to the majority of Tri-State load would make this option significantly less than optimal.

- Limon and Burlington: Rather than facility expansion, Tri-State will seek to utilize existing surplus interconnect for renewable generation to be co-located at these sites. The process and benefits for utilization of surplus interconnection are described in the Direct Testimony of Ms. Hunter and Mr. Hubbard.

Q: PLEASE OUTLINE THE HIGH-LEVEL STEPS THAT WILL ENABLE THIS UNIT TO COME ONLINE.

A: Following the Phase I plan approval and selection of an Engineering, Procurement, and Construction ("EPC") contractor for the natural gas facility through the Phase II procurement processes, Tri-State anticipates filing an Application seeking a Certificate of Public Convenience and Necessity ("CPCN") from the Commission if the resource is sited in Colorado. If the resource were sited in Wyoming, Tri-State would instead seek a permit from the Wyoming Industrial Siting Council. Site selection, obtaining land rights, and environmental permitting processes for both the NGCC unit and CCS emission controls would be supported by the EPC contractor, and the transmission interconnection process would be discussed by Mr. Hubbard in that future filing.

Q: WHAT STEPS IS TRI-STATE TAKING TO INFORM THE PHASE II PROCESS RELATED TO GAS RESOURCE SELECTION?

A: Tri-State has engaged a third-party consulting firm to perform a siting study to analyze factors related to siting this new gas resource, including land availability, assessing gas pipeline accessibility, transmission interconnection availability, water availability, and carbon sequestration viability.

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Q: HOW WILL SELECTION OF AN EPC CONTRACTOR BE DETERMINED?

A: Tri-State intends to issue a Dispatchable Resources RFP as part of its 2023 ERP Phase II process to obtain competitive bids for the gas resource and associated EPC contractor costs and requirements. Ms. Hunter's Direct Testimony further discusses this process in more detail.

Q: DOES TRI-STATE INTEND TO BE THE GAS FACILITY OPERATOR OR OBTAIN AN OPERATIONS AND MAINTENANCE CONTRACTOR?

A: Tri-State has not firmly determined all facets of the proposed gas unit's operations given the current stage of the modeling and planning process but anticipates that Tri-State would be the facility operator.

Q: DOES TRI-STATE INTEND TO USE A PROJECT LABOR AGREEMENT FOR CONSTRUCTION OF THE FACILITY?[8]

A: Tri-State's mission is to provide our Member systems a reliable, affordable, and responsible supply of electricity in accordance with cooperative principles. Tri-State is committed to competitively bidding all major contracts to ensure affordability goals are met. As such, Tri-State has not made a determination whether or not a labor agreement will be utilized for the construction of the new gas facility. However, if the new gas facility is located in the original Colorado Ute territory, then the on-site Tri-State Operations and Maintenance craft labor would be subject to Tri-State's collective bargaining agreement with the IBEW Local 111.

Q: HOW WILL THE 2031 IMPLEMENTATION OF CCS BENEFIT THE NATURAL

[8] Rule 3605(g)(II)(b) requires that the utility "…specify whether it agrees to use a project labor agreement for the construction or expansion of a generation facility."

GAS PLANT INVESTMENT FOR TRI-STATE MEMBERS?

A: Tri-State's modeling, based on industry research and vendor data, forecasts achieving up to a 97 percent carbon capture rate which results in a transformative reduction in the plant's carbon dioxide emissions from 765 lbs per net MWh (pre-CCS) to a possible low of 23 lbs per net MWh (post-CCS).[9] Additionally, with this carbon reduction, the facility's useful life can reasonably be extended beyond 20 years to 30 years.

Q: WHAT IS THE LIFE OF A COMBINED CYCLE GAS RESOURCE?

A: From a technical perspective, a newly constructed, highly efficient NGCC with CCS unit can be expected to operate for 30 years. From a modeling perspective, as identified in **Attachment** LKT-7 ~~**B** of the ERP Report (**Attachment LKT-1**),~~ the assumed life of the combined cycle gas resource with CCS is 30 years. In Tri-State's 2020 ERP Phase II, the book life of gas resources was limited to 20 years pursuant to the 2020 ERP Phase I Settlement Agreement.[10] However, the gas resource selected in the IRA Scenario includes application of CCS which extends the life of the resource back to normal operational expectations, while meeting existing emission targets and in anticipation of potential future environmental regulations. A 30-year operating lifetime assumption is consistent with Tri-State's expectations for actual unit depreciation and amortization.

Q: DOES THE 2027 ERP PROVIDE AN OPPORTUNITY TO ASSESS THE

[9] Federal PTC eligibility requires a carbon capture rate of at least 75 percent. Tri-State intends to evaluate Phase II gas bids that have a carbon capture rate between 75-97 percent.
[10] Section 3.6.8.

CONTINUED VIABILITY OF THE 2031 CCS CONVERSION PATH FOR MANAGING CARBON FOR THE GAS PLANT?

A: At the time of the 2027 ERP Phase I filing anticipated on June 1, 2027, Tri-State will provide the Commission and stakeholders with an update on CCS conversion progress.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

PROCEEDING NO. 23A-____E

APPLICATION OF TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC. FOR APPROVAL OF ITS 2023 ELECTRIC RESOURCE PLAN

VERIFICATION

STATE OF COLORADO)
) ss:
COUNTY OF ADAMS)

I, Barry W. Ingold, 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.

Subscribed and sworn to before me this 15th day of November 2023, at Westminster, Colorado.

FAITH WARNER
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 20184035614
MY COMMISSION EXPIRES 09/07/2026

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

By: Barry W. Ingold
Barry W. Ingold
Chief Operating Officer

Witness my hand and official seal.

Faith Warner
Notary Public

My Commission expires: 9/7/2026.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-25-14

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-51:
Tri-State 2020 ERP

TRI-STATE
Generation and Transmission Association, Inc.

A Touchstone Energy® Cooperative

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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[redacted]

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]	[redacted]	~$800	$54.03	$0.129	CRG (Inc)
Craig 2	[redacted]	[redacted]	~$500	$54.76	$0.131	CRG (Inc)
Craig 3	[redacted]	[redacted]	~$3,000	$48.70	$0.124	CRG (Inc)
LRS 2	[redacted]	[redacted]	~$1,500	$51.33	$0.111	LRSG
LRS 3	[redacted]	[redacted]	~$1,500	$56.08	$0.108	LRSG
SPV3	[redacted]	[redacted]	~$6,500	$48.94	$0.138	SPV3

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[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

<u>Contract Profile Information:</u>

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	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.

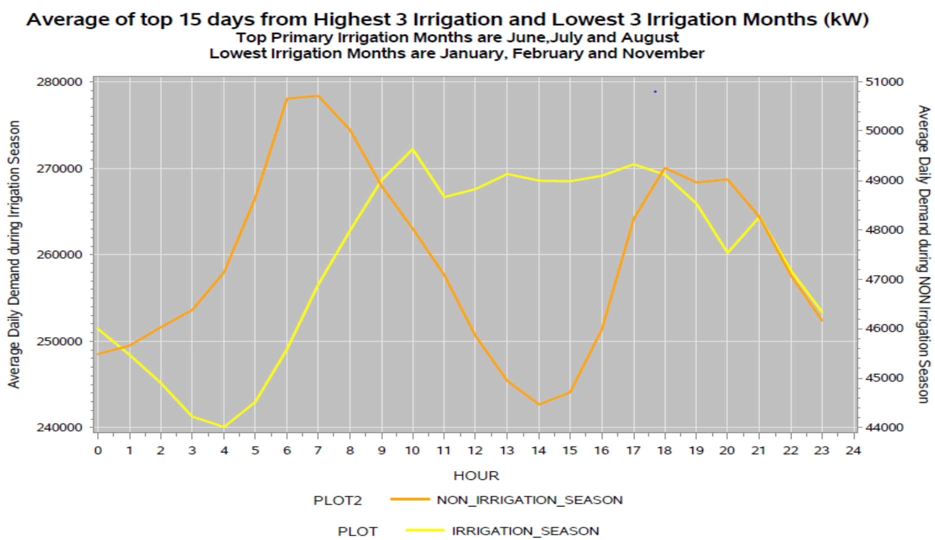

Figure 14: Basin Electrically East Irrigation and Non-Irrigation Seasons Demand Profiles

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	[redacted]	
Basin Electrically East		
CRSP	$12.19	$5.18
LAP	$15.72	$4.12
Native American WAPA Allocations	[redacted]	
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)	[redacted]					
	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

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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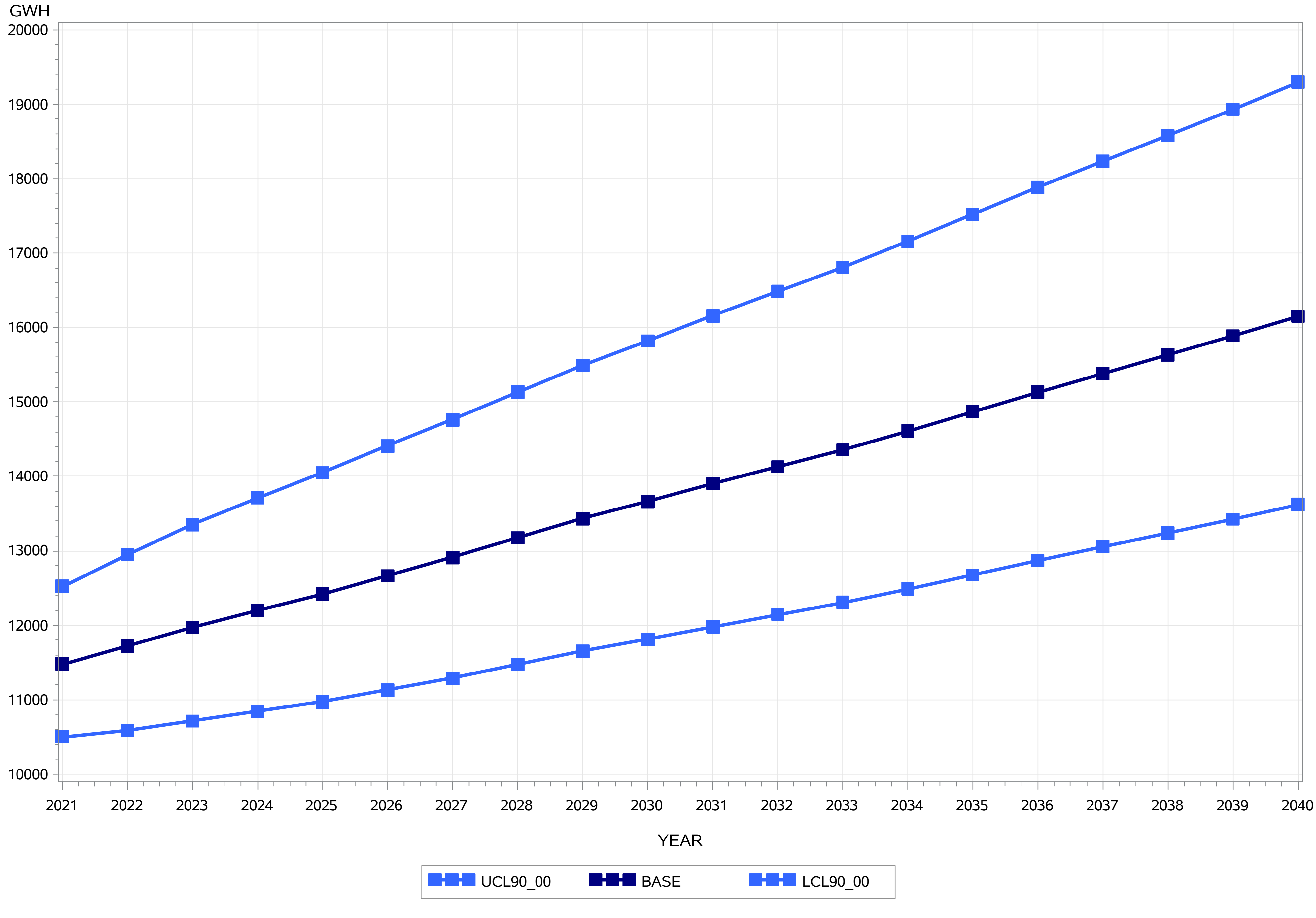
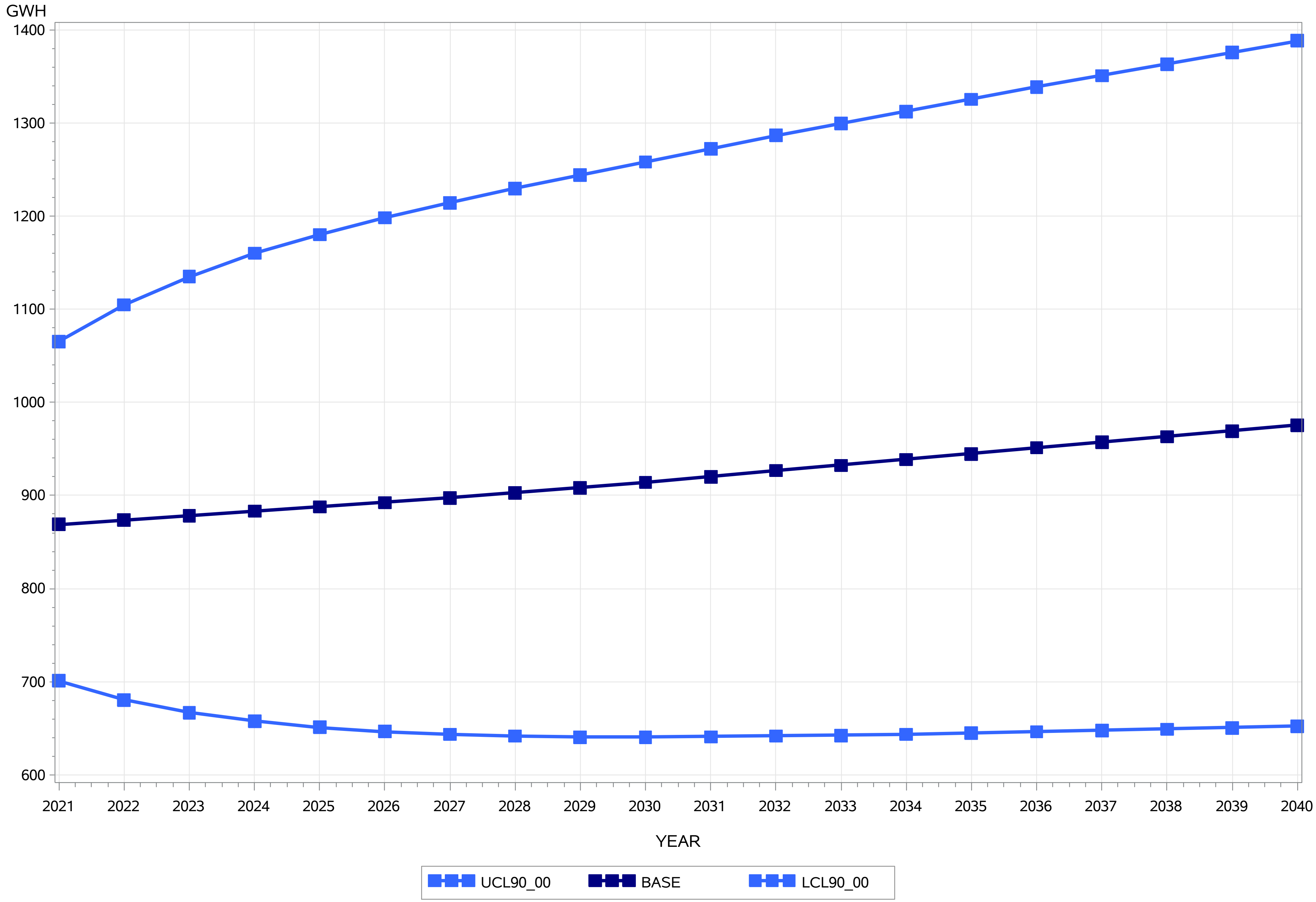
Attachment Vol II 1-1 Tri-State Load Forecasts by State & Member

Total Annual Energy Sales
STATE OF COLORADO

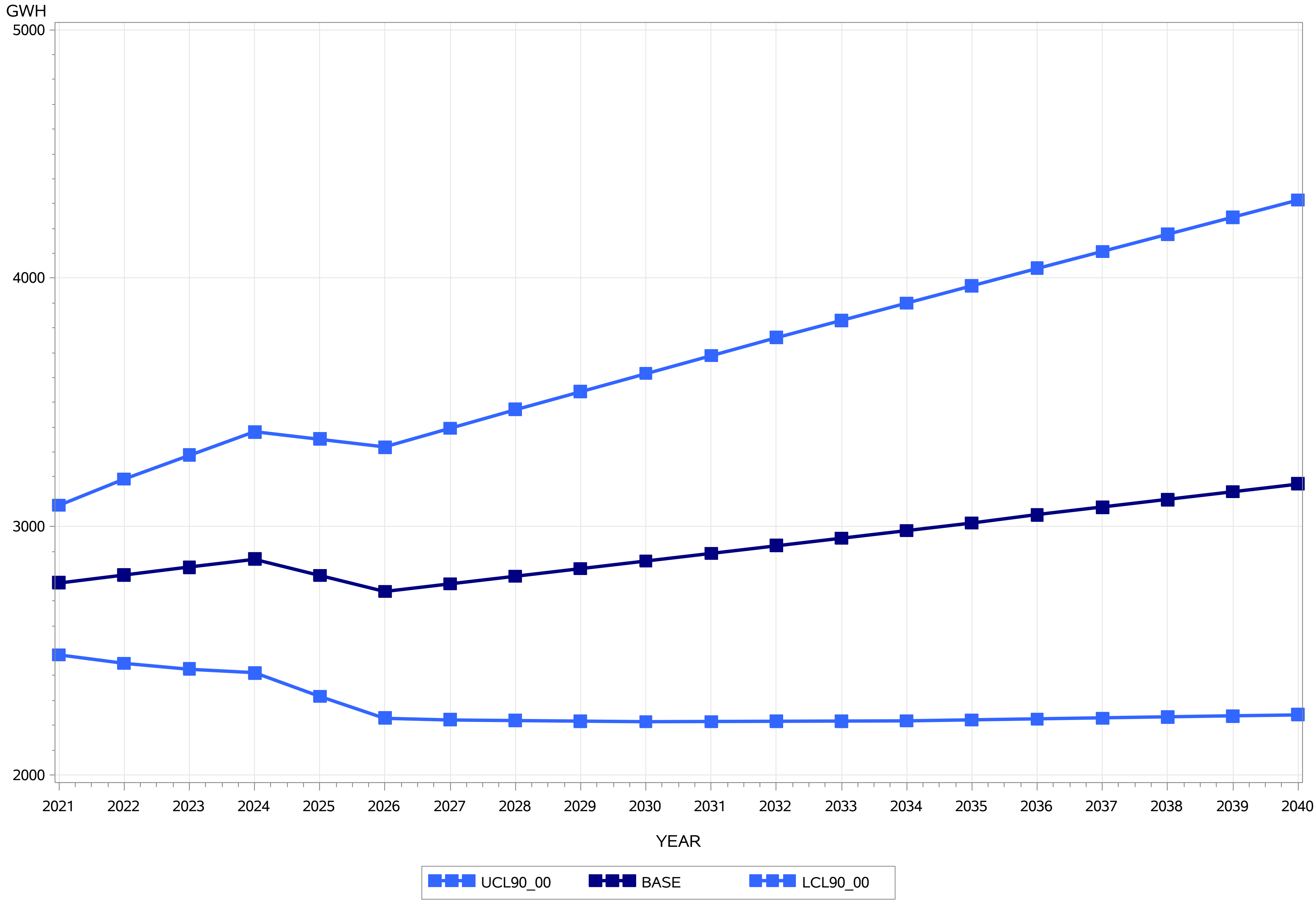


PUBLIC

Total Annual Energy Sales
STATE OF NEBRASKA



Total Annual Energy Sales
STATE OF NEW MEXICO



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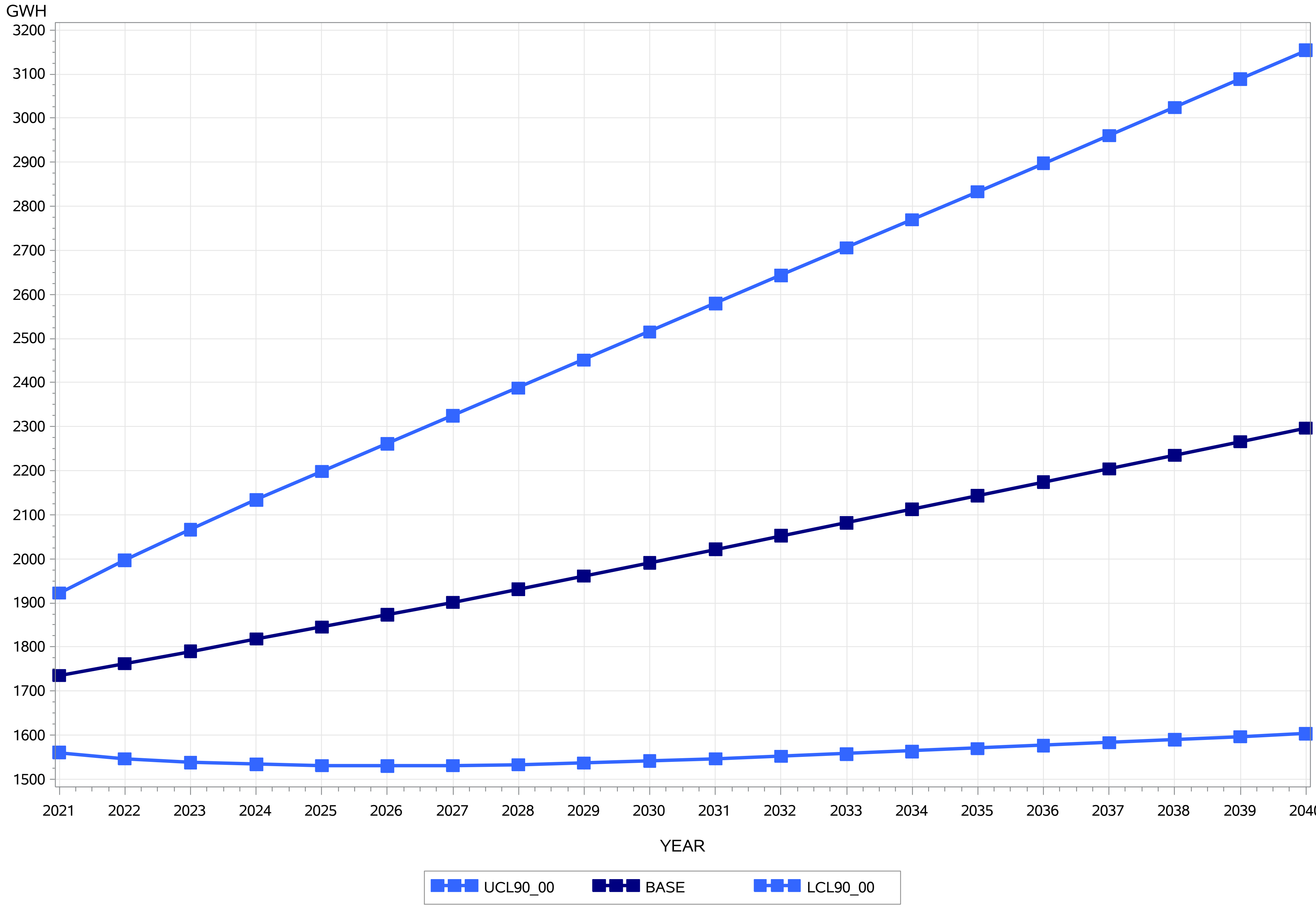
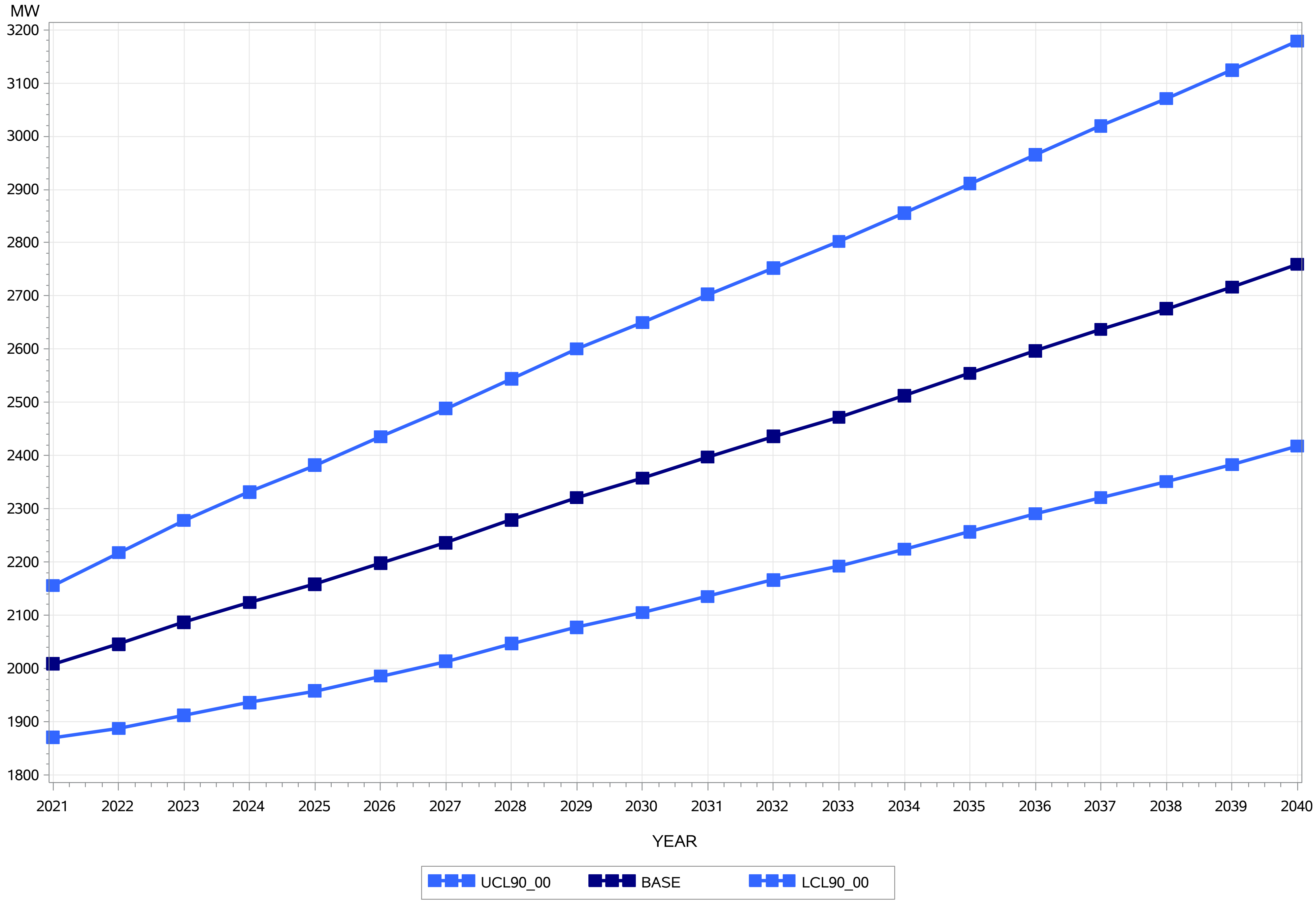
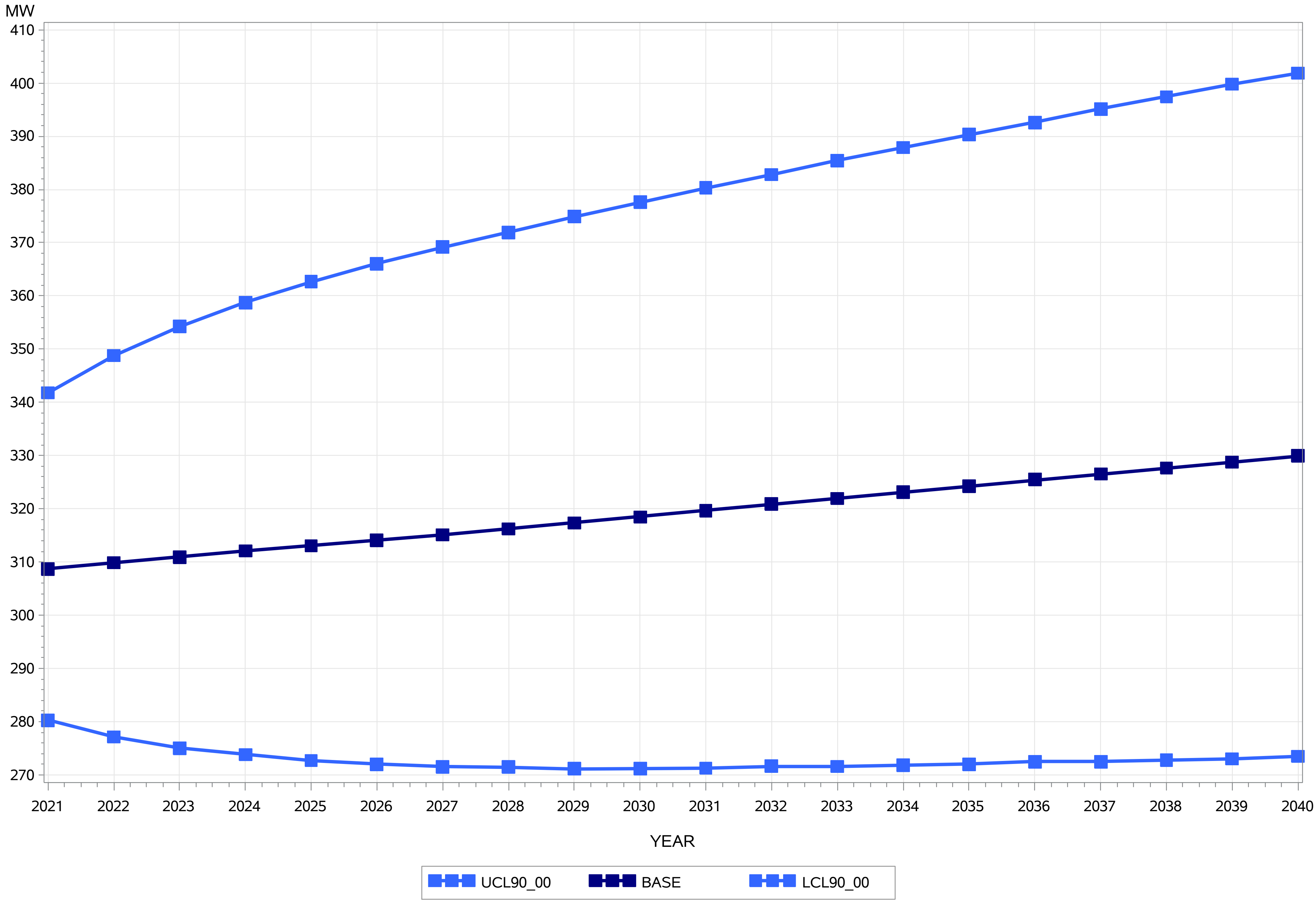
Total Annual Energy Sales
STATE OF WYOMING



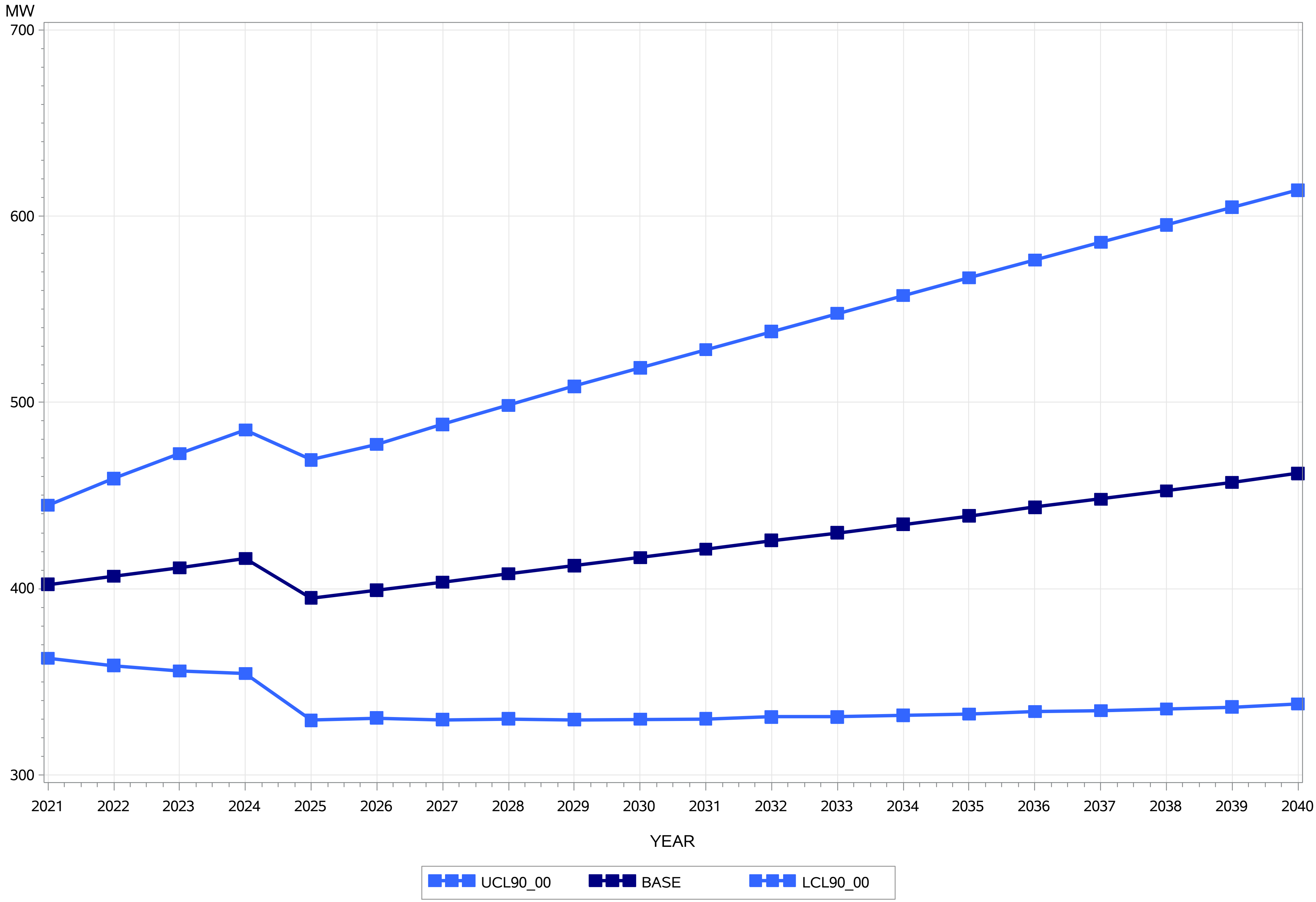
Annual Summer Coincident Peak
STATE OF COLORADO



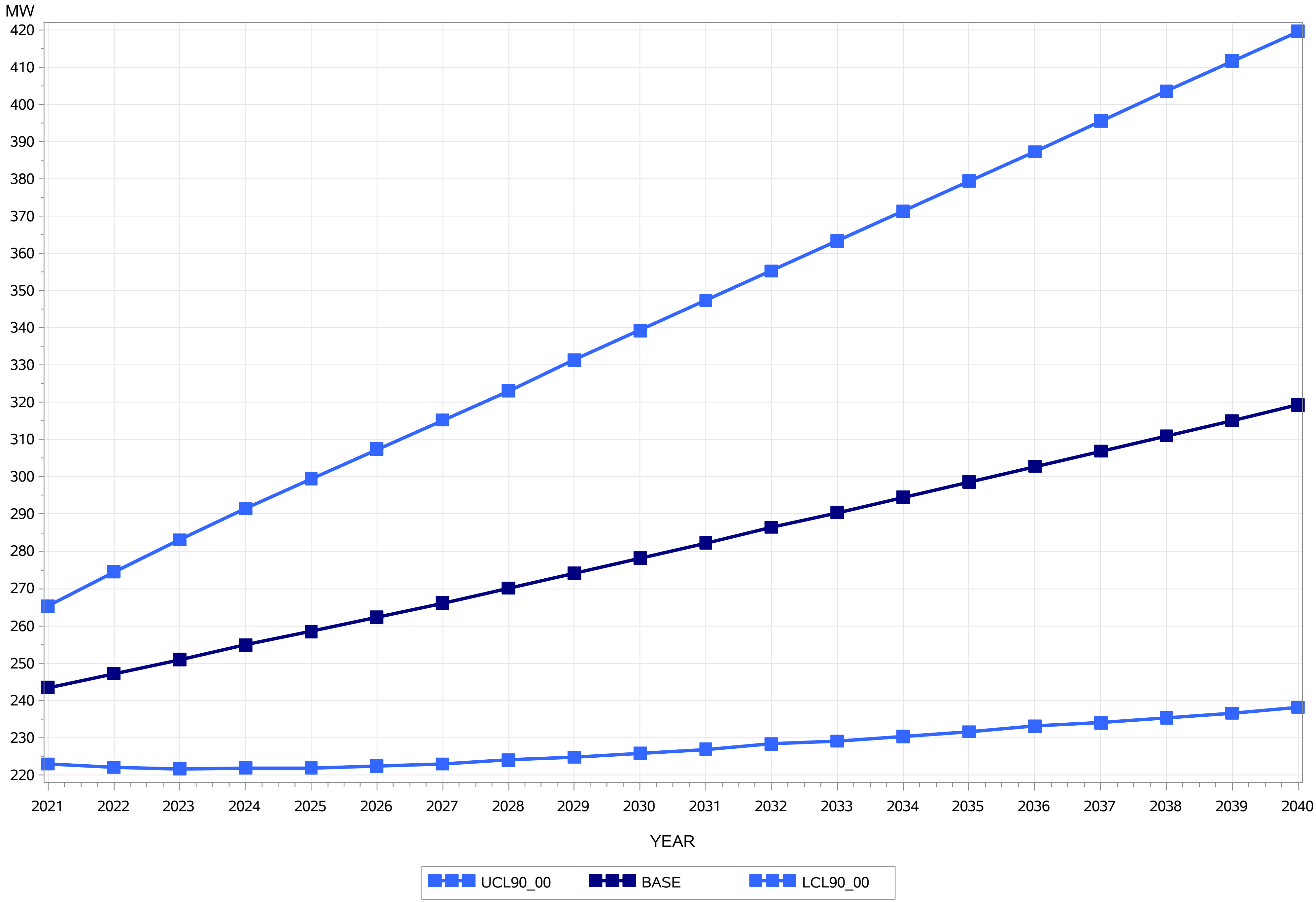
Annual Summer Coincident Peak
STATE OF NEBRASKA



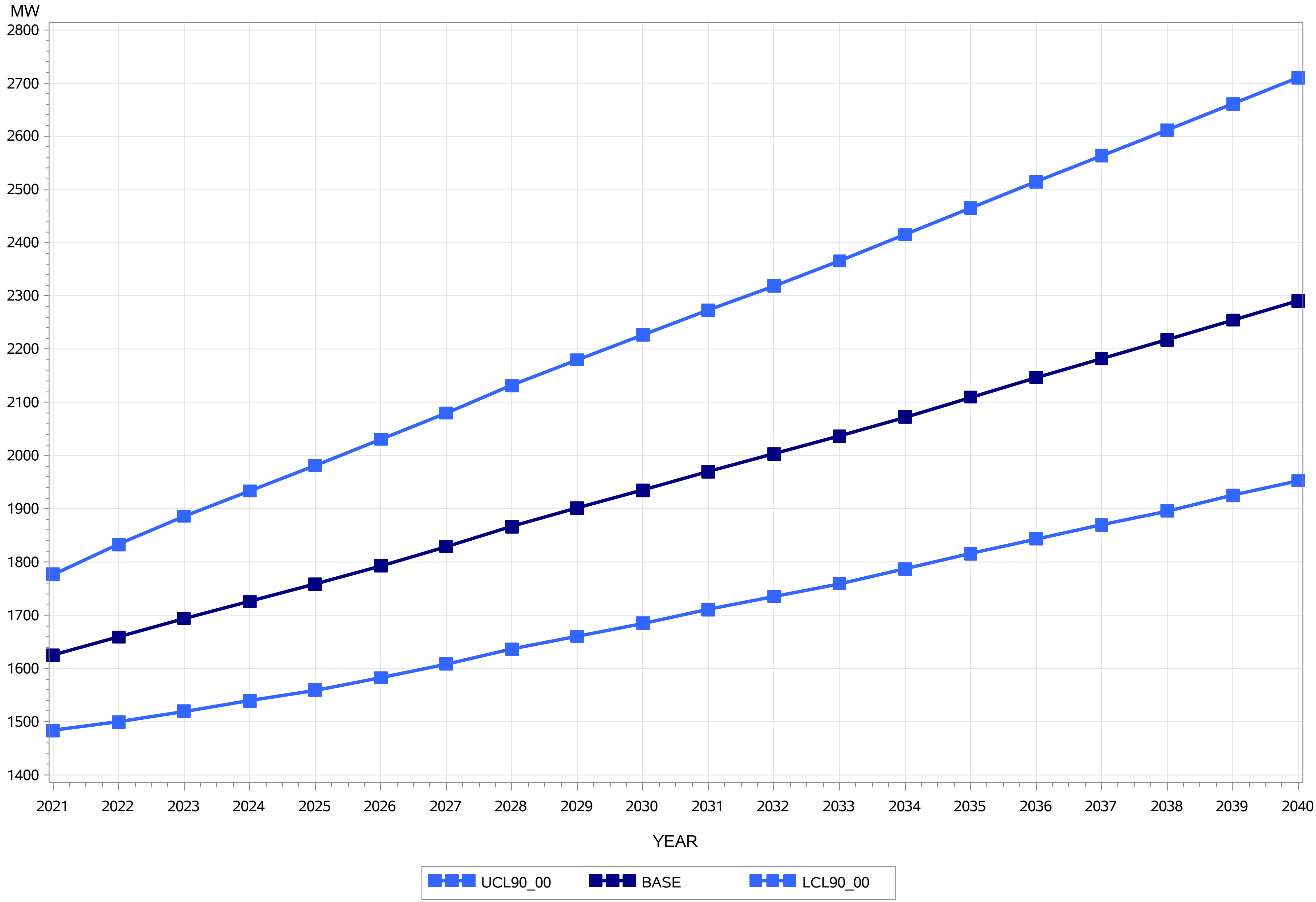
Annual Summer Coincident Peak
STATE OF NEW MEXICO



Annual Summer Coincident Peak
STATE OF WYOMING

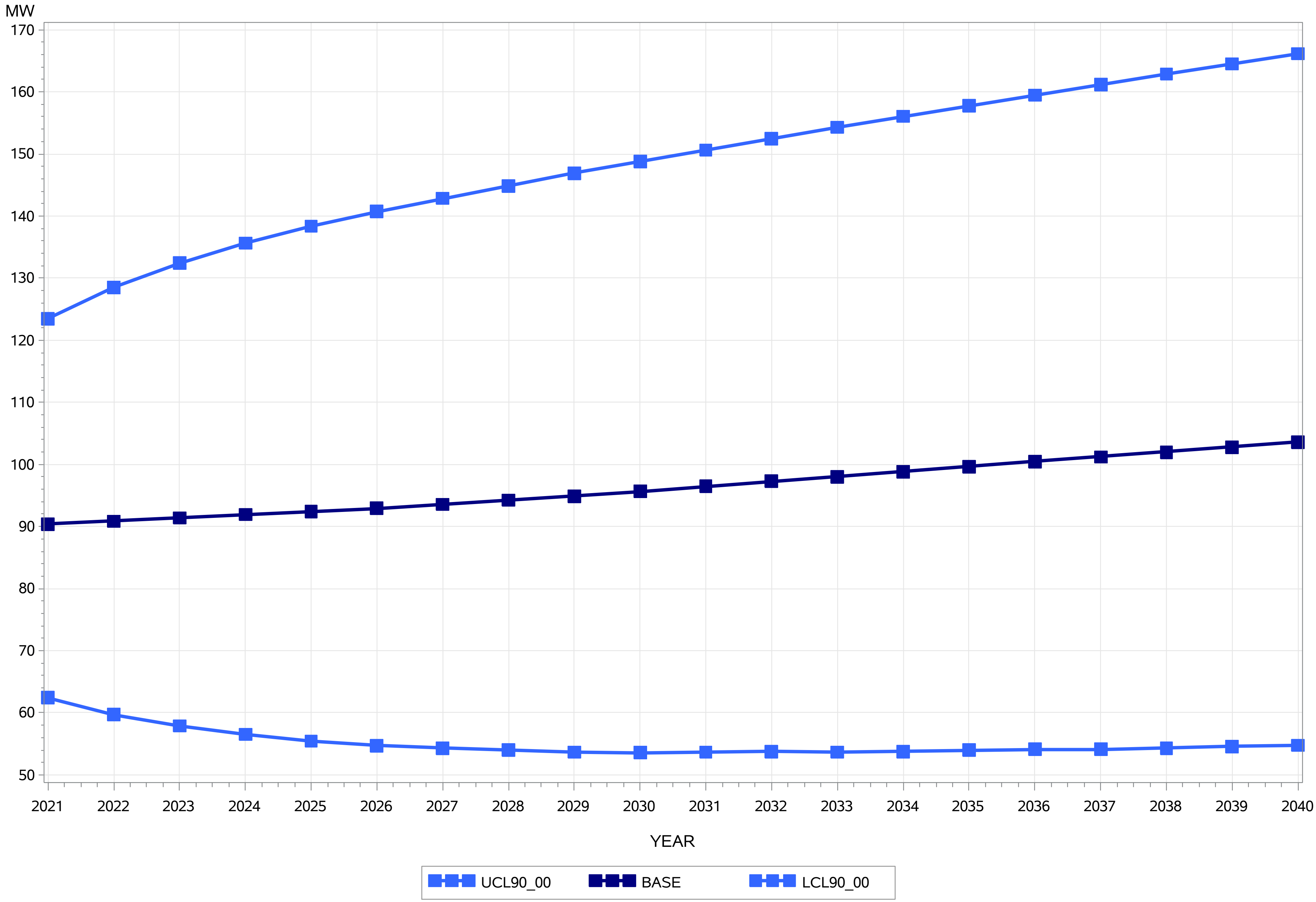


Annual Winter Coincident Peak
STATE OF COLORADO



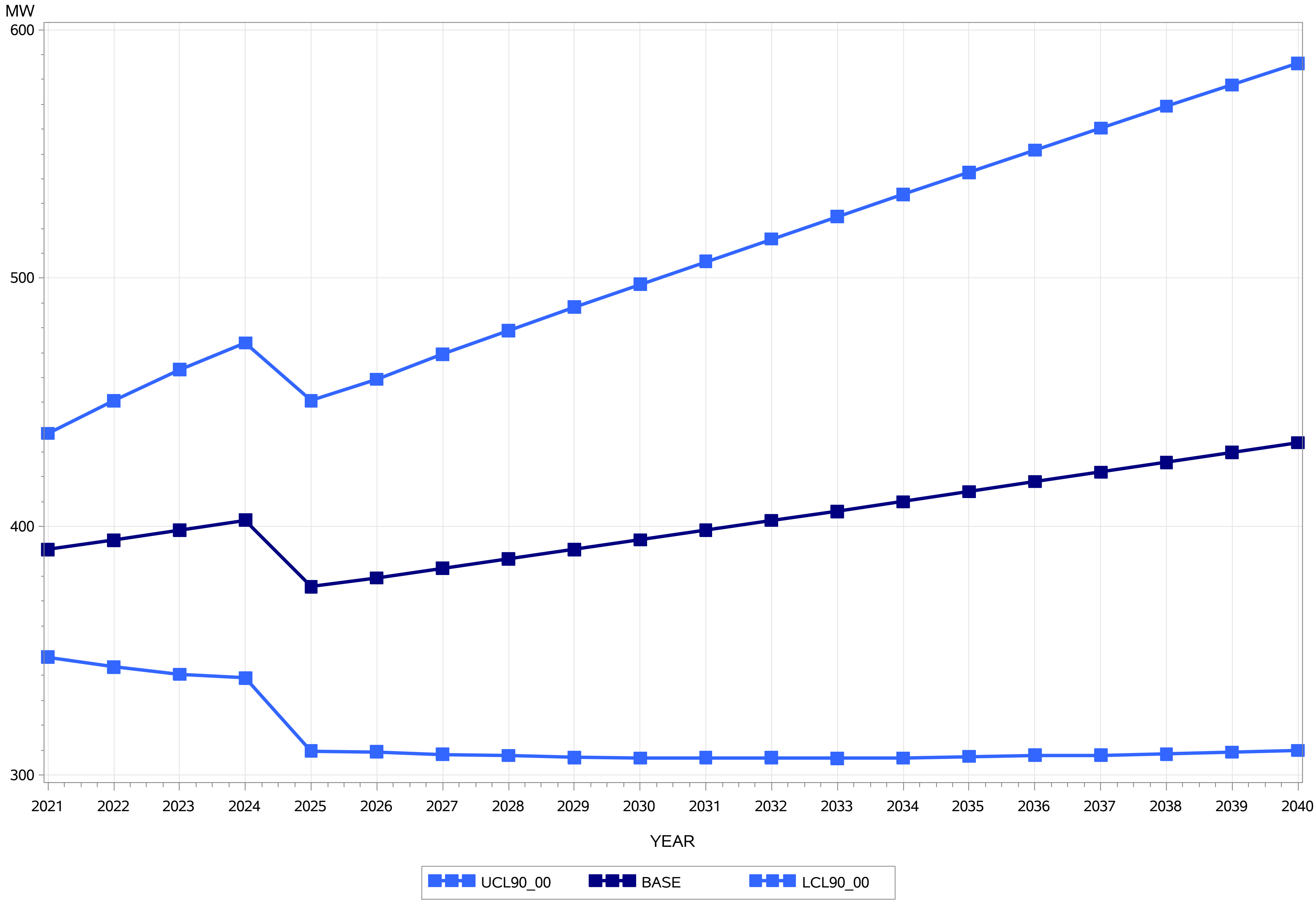
PUBLIC

Annual Winter Coincident Peak
STATE OF NEBRASKA



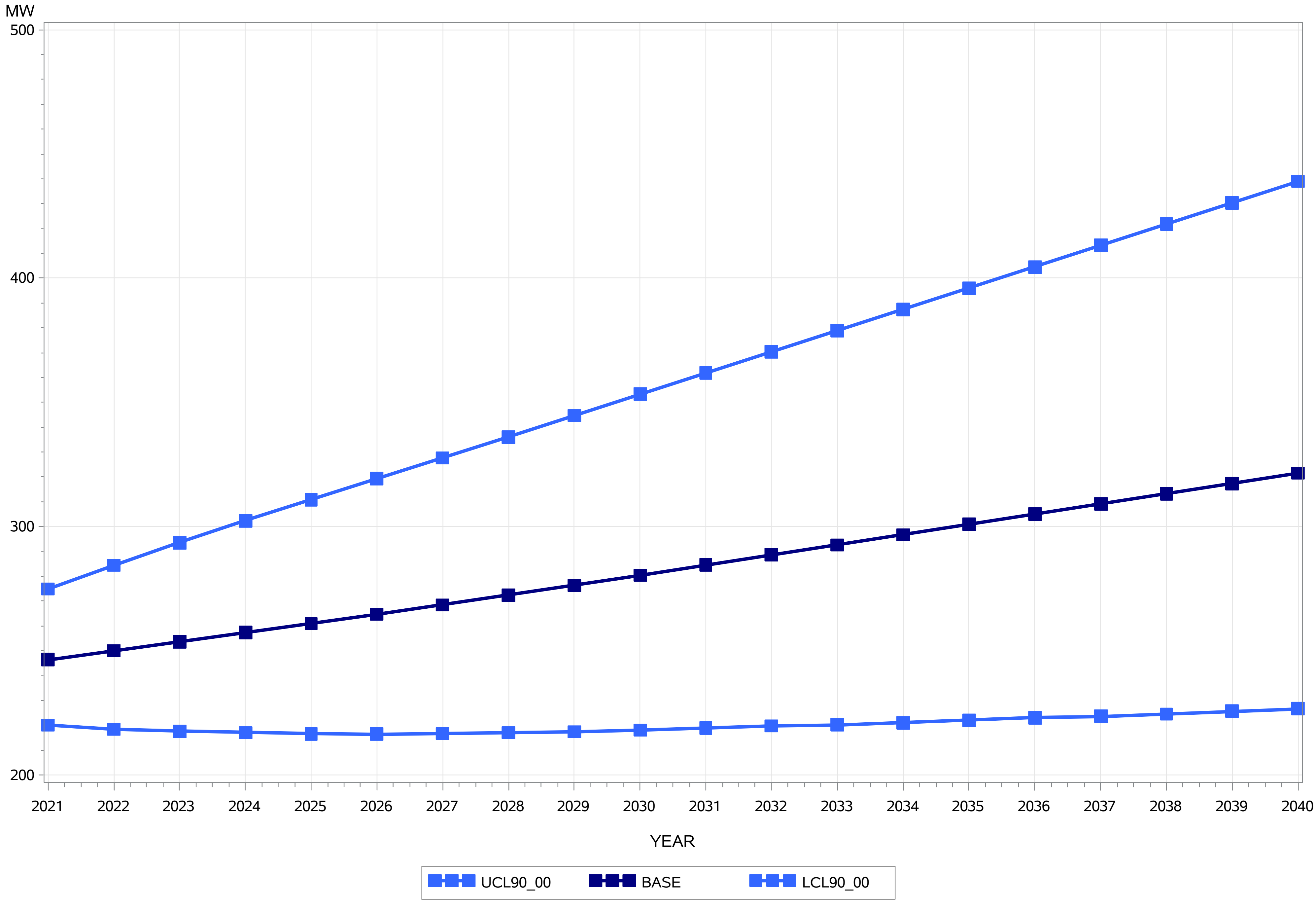
PUBLIC

Annual Winter Coincident Peak
STATE OF NEW MEXICO



Annual Winter Coincident Peak

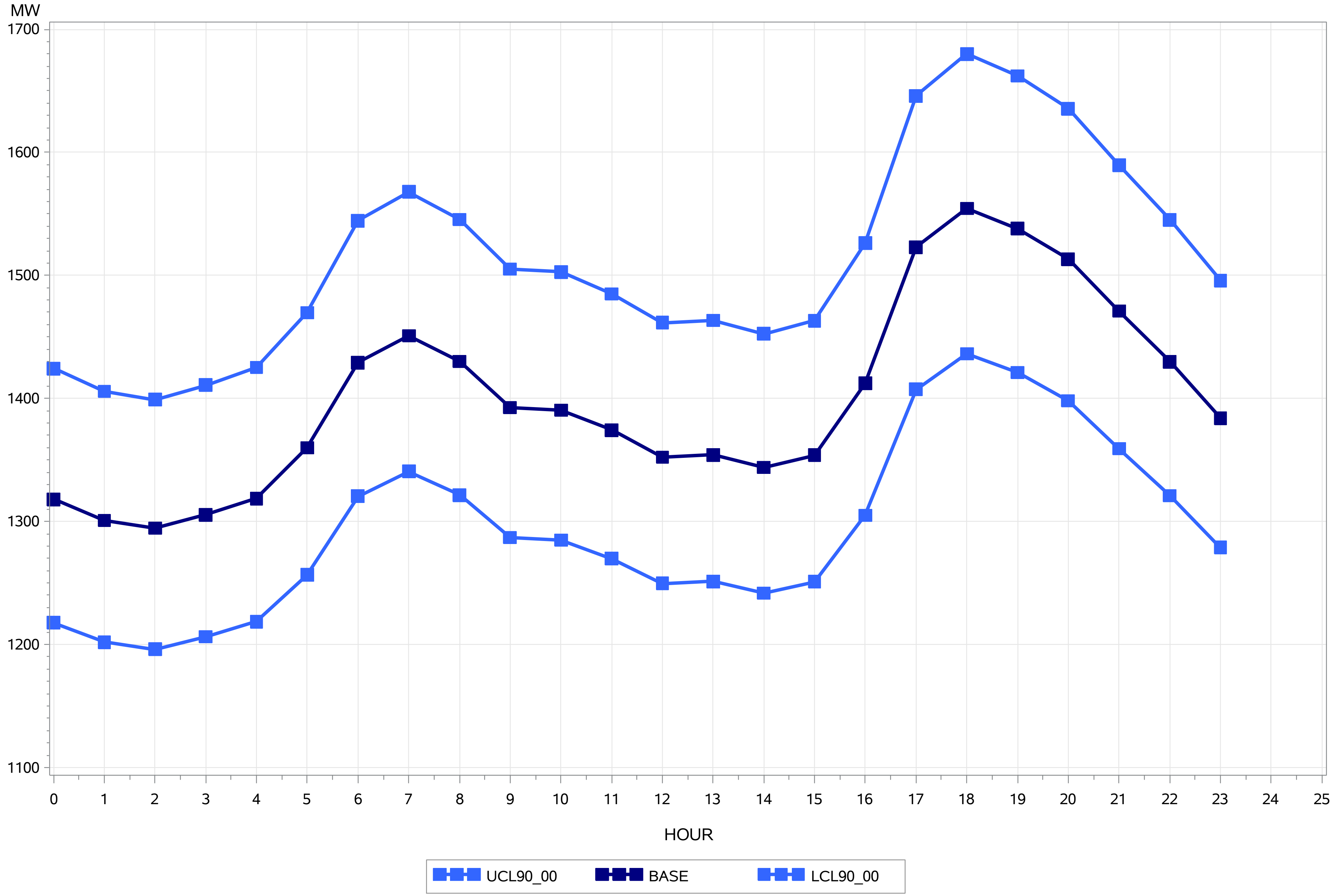
STATE OF WYOMING



Member Forecasted On Peak Demand Day for January 2021

STATE OF COLORADO

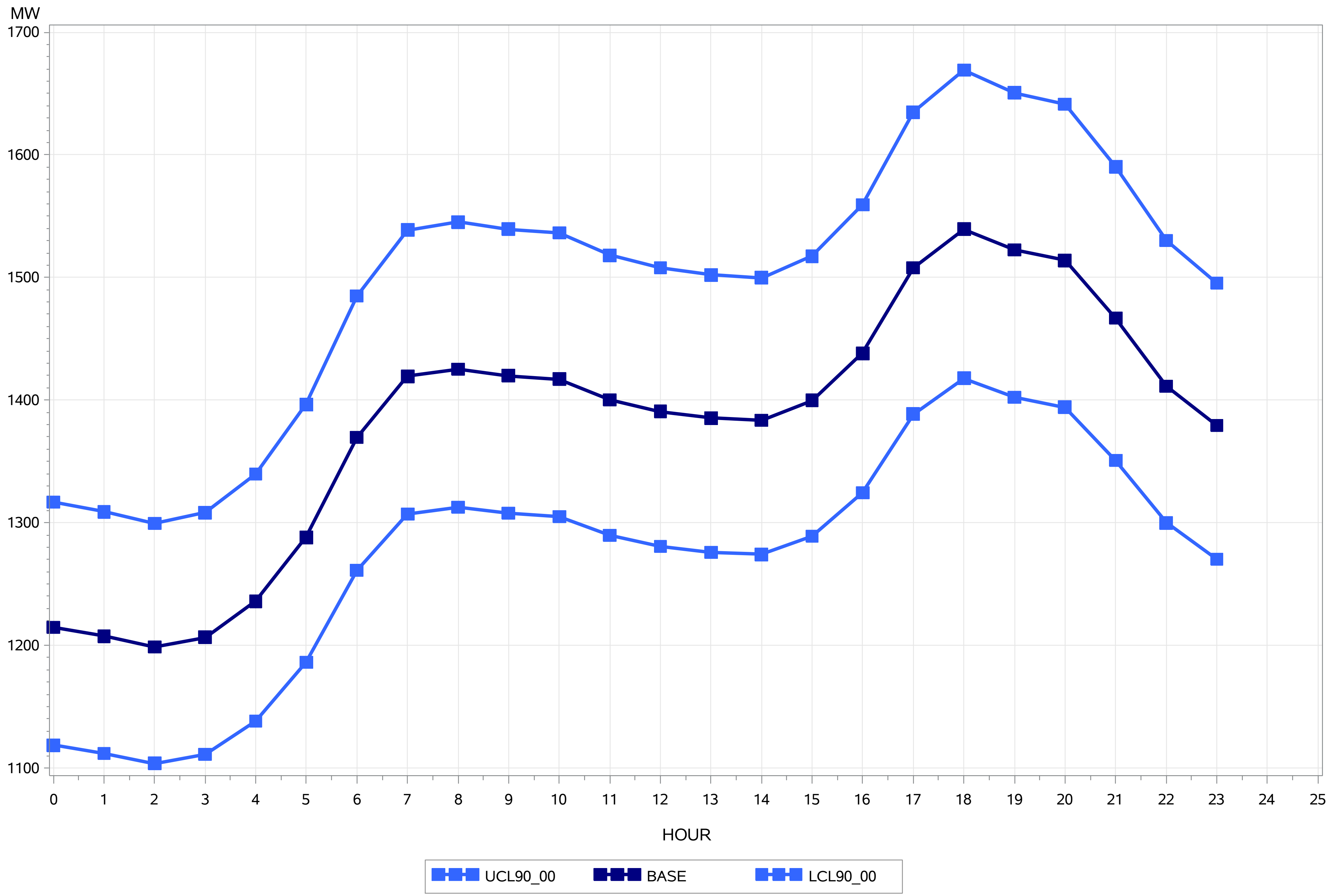
Date of On Peak Day - 01/06/2021



Member Forecasted On Peak Demand Day for February 2021

STATE OF COLORADO

Date of On Peak Day - 02/01/2021

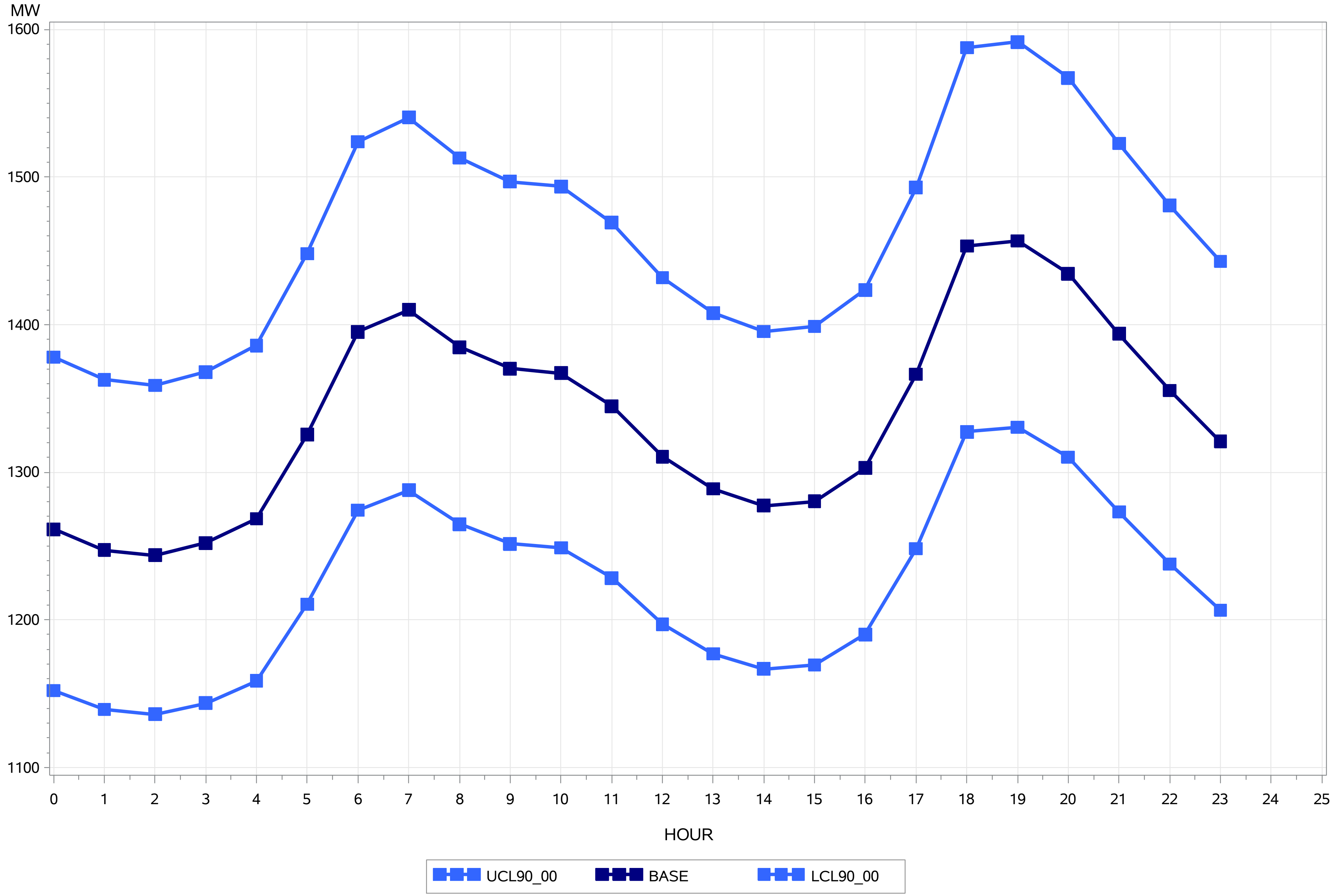


PUBLIC

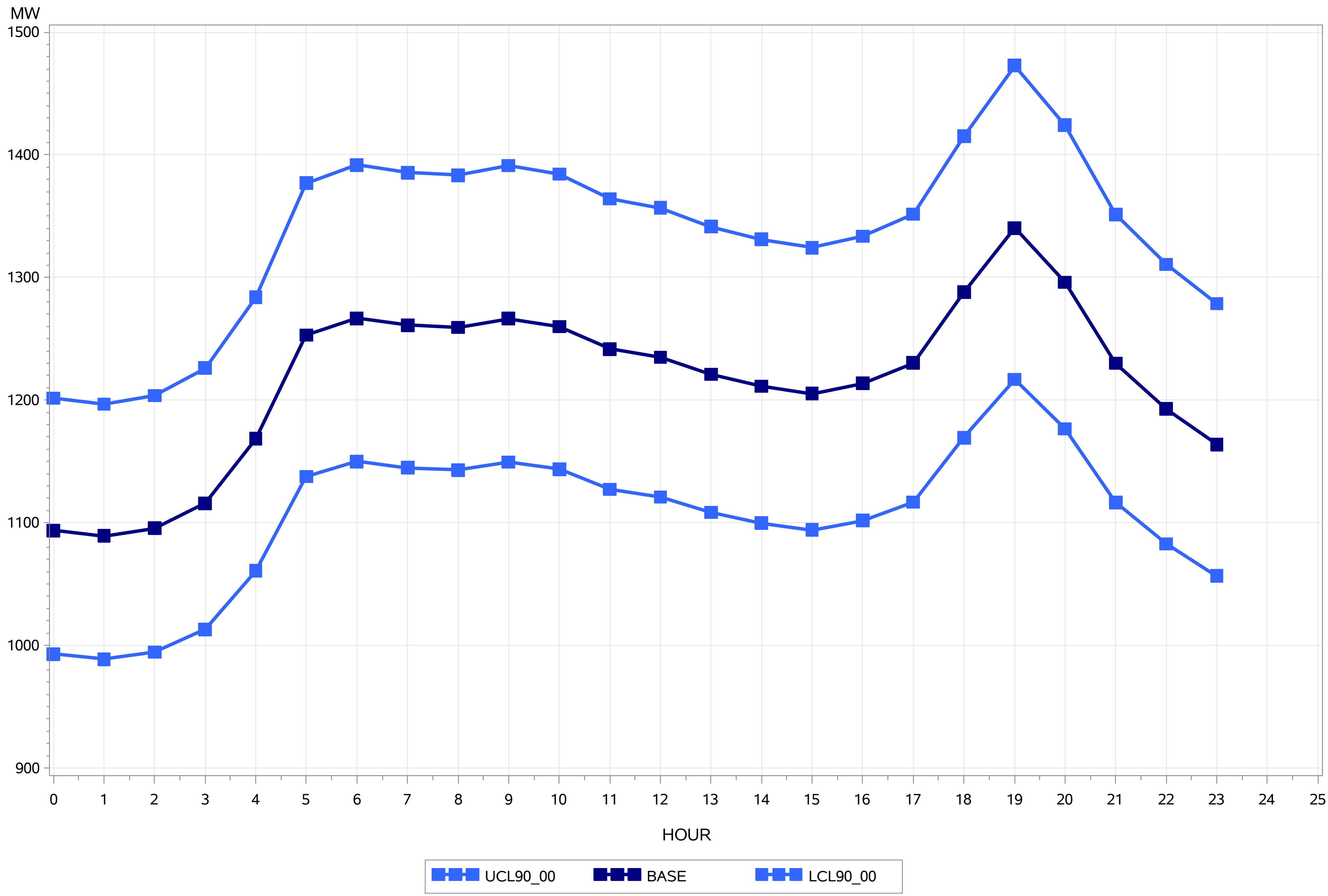
Member Forecasted On Peak Demand Day for March 2021

STATE OF COLORADO

Date of On Peak Day - 03/01/2021



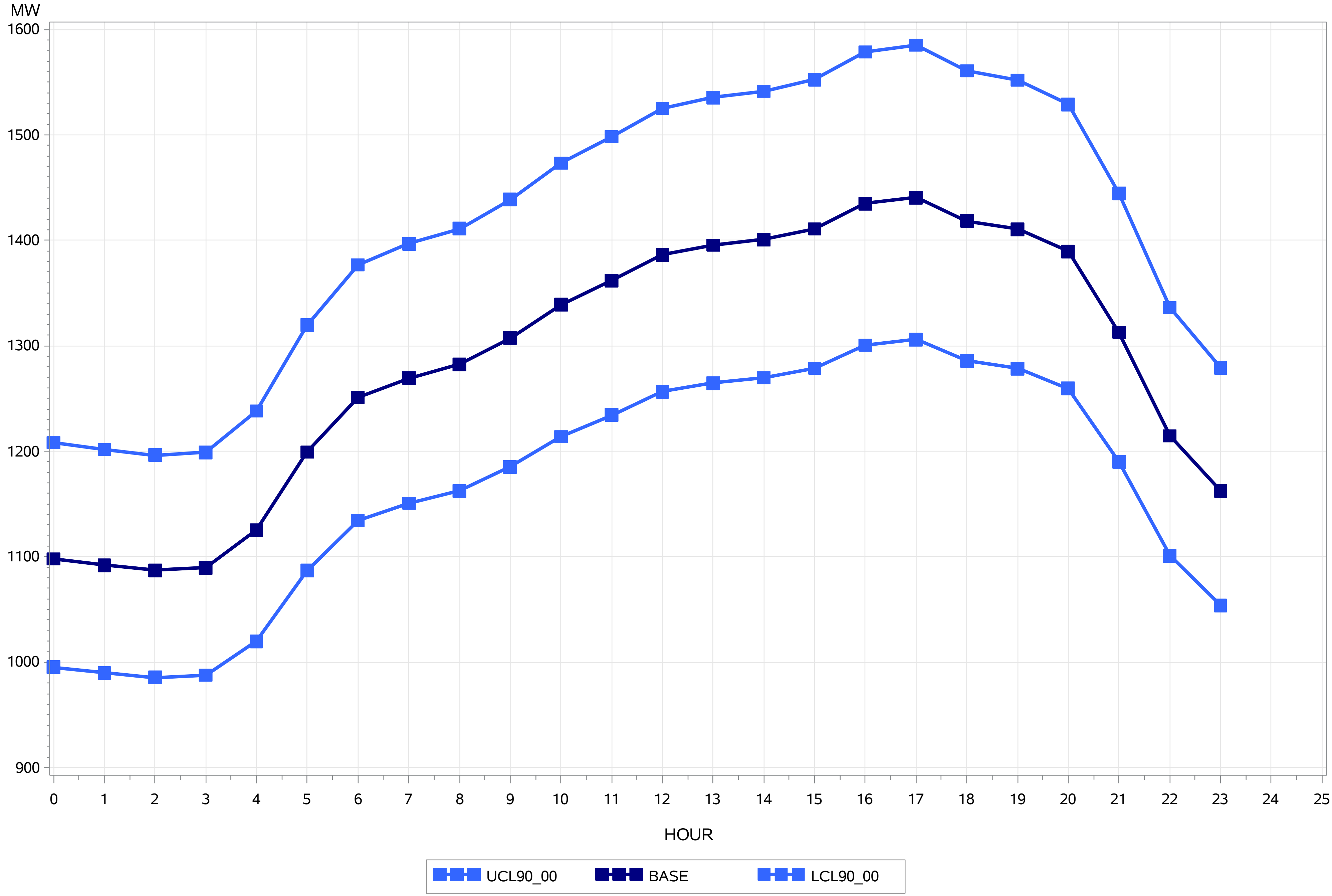
Member Forecasted On Peak Demand Day for April 2021
STATE OF COLORADO
Date of On Peak Day - 04/15/2021



Member Forecasted On Peak Demand Day for May 2021

STATE OF COLORADO

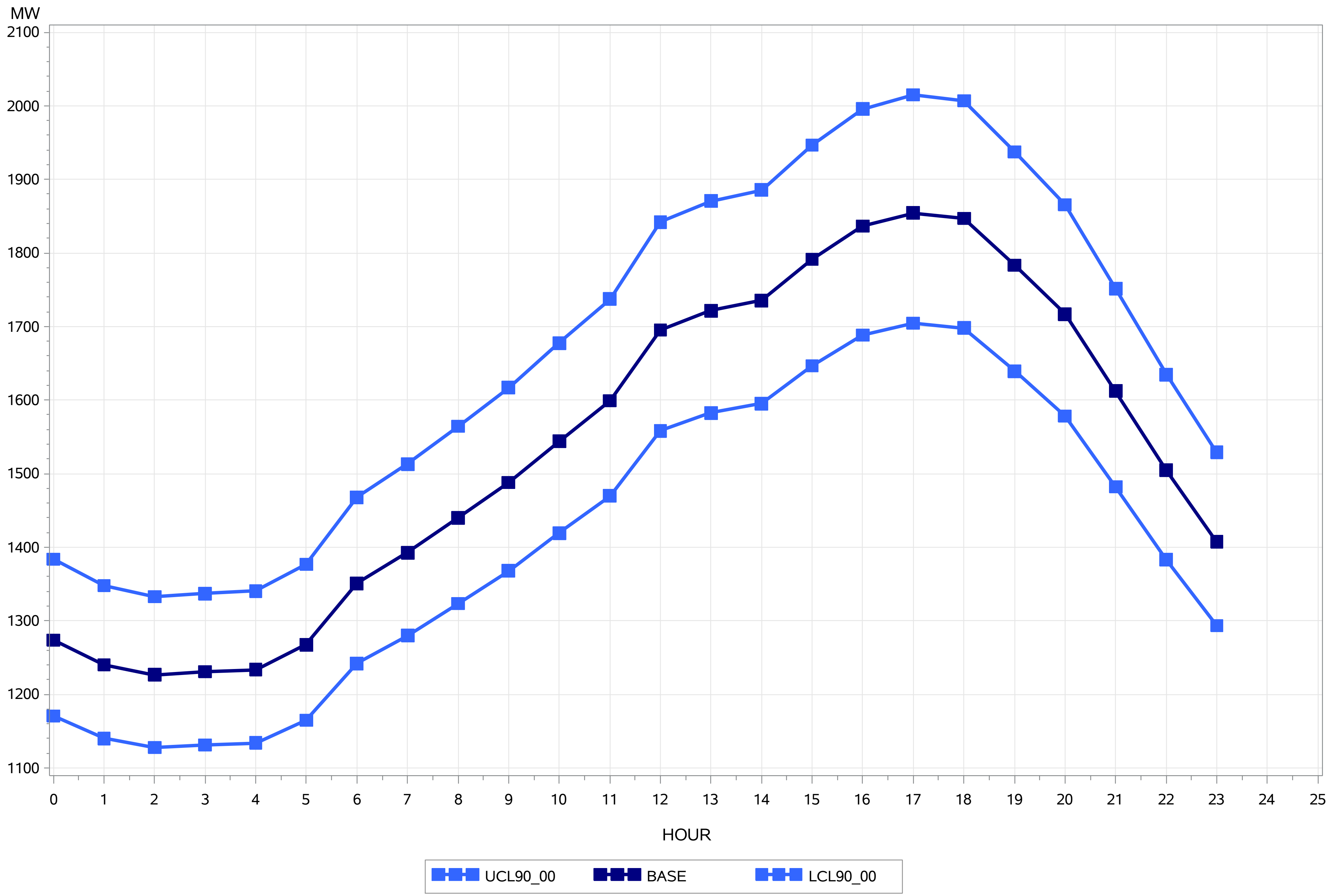
Date of On Peak Day - 05/31/2021



Member Forecasted On Peak Demand Day for June 2021

STATE OF COLORADO

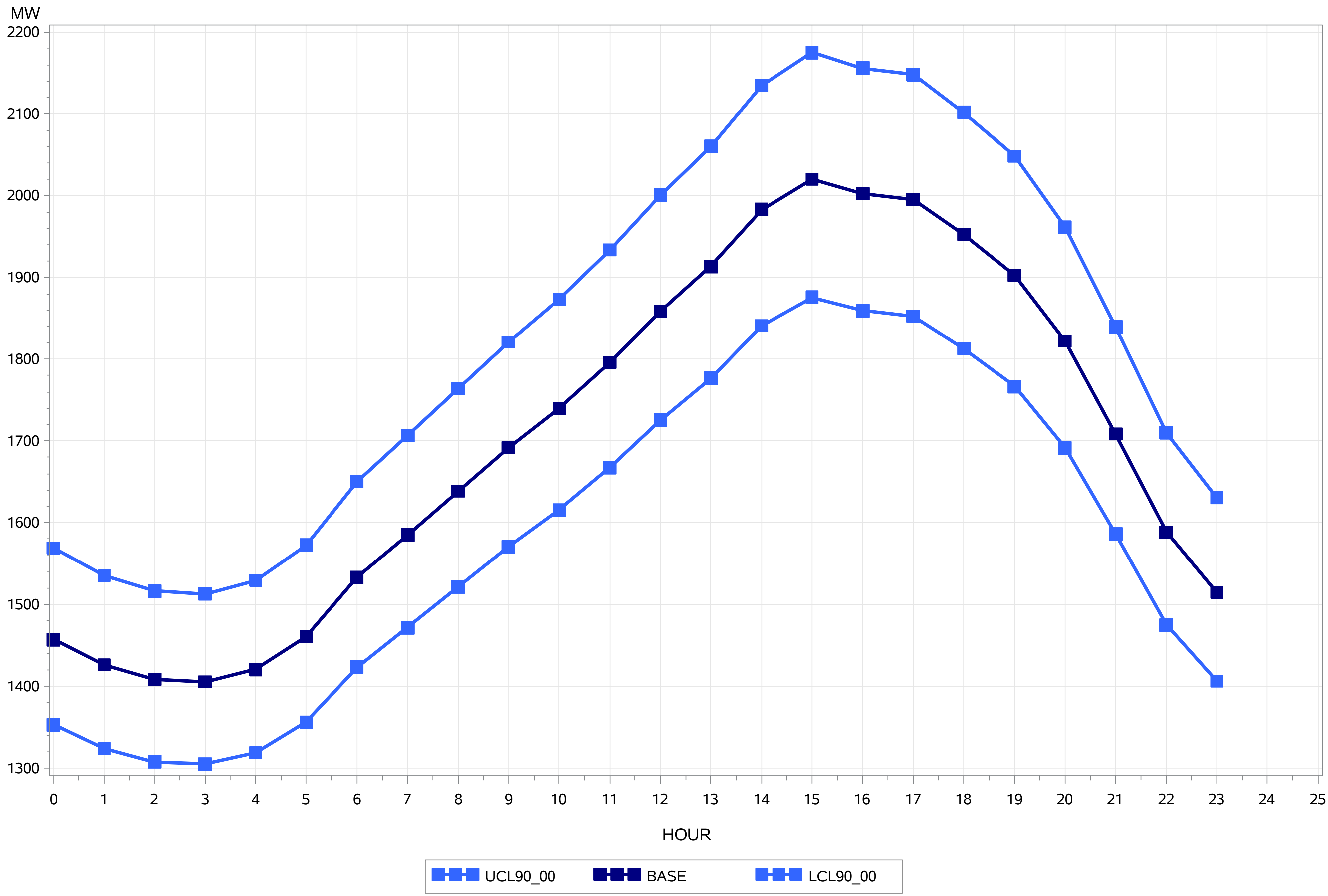
Date of On Peak Day - 06/28/2021



Member Forecasted On Peak Demand Day for July 2021

STATE OF COLORADO

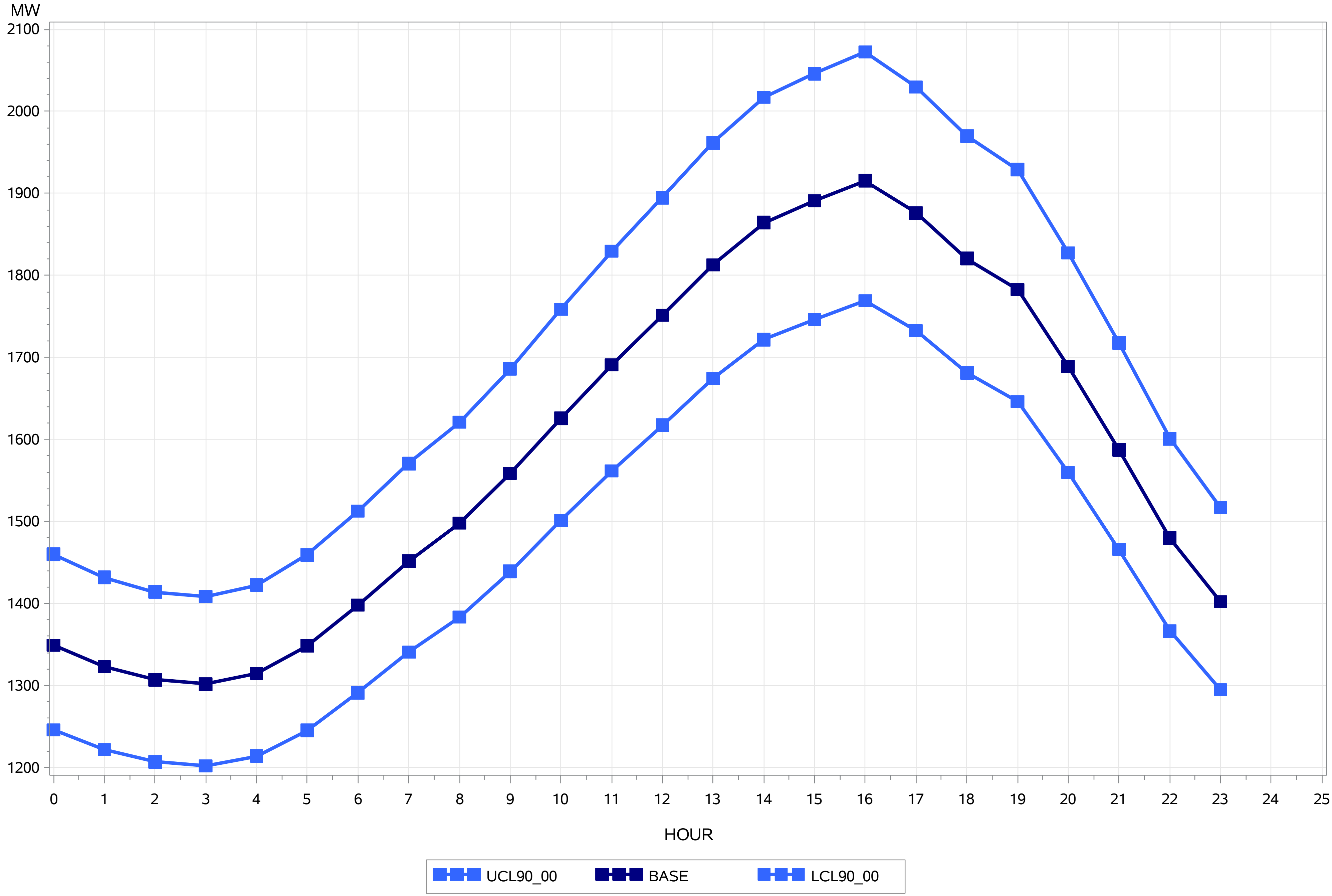
Date of On Peak Day - 07/22/2021



Member Forecasted On Peak Demand Day for August 2021

STATE OF COLORADO

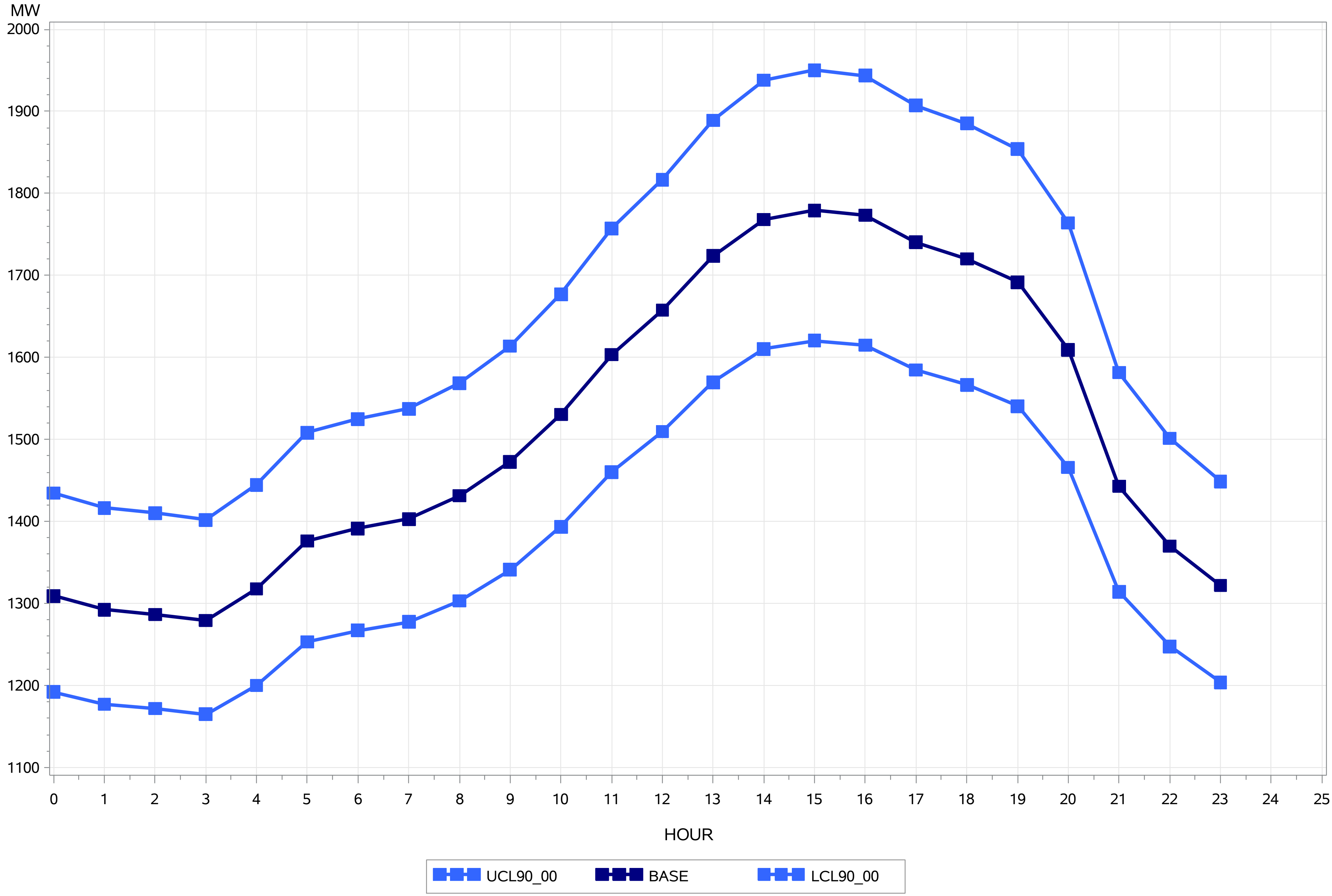
Date of On Peak Day - 08/28/2021



Member Forecasted On Peak Demand Day for September 2021

STATE OF COLORADO

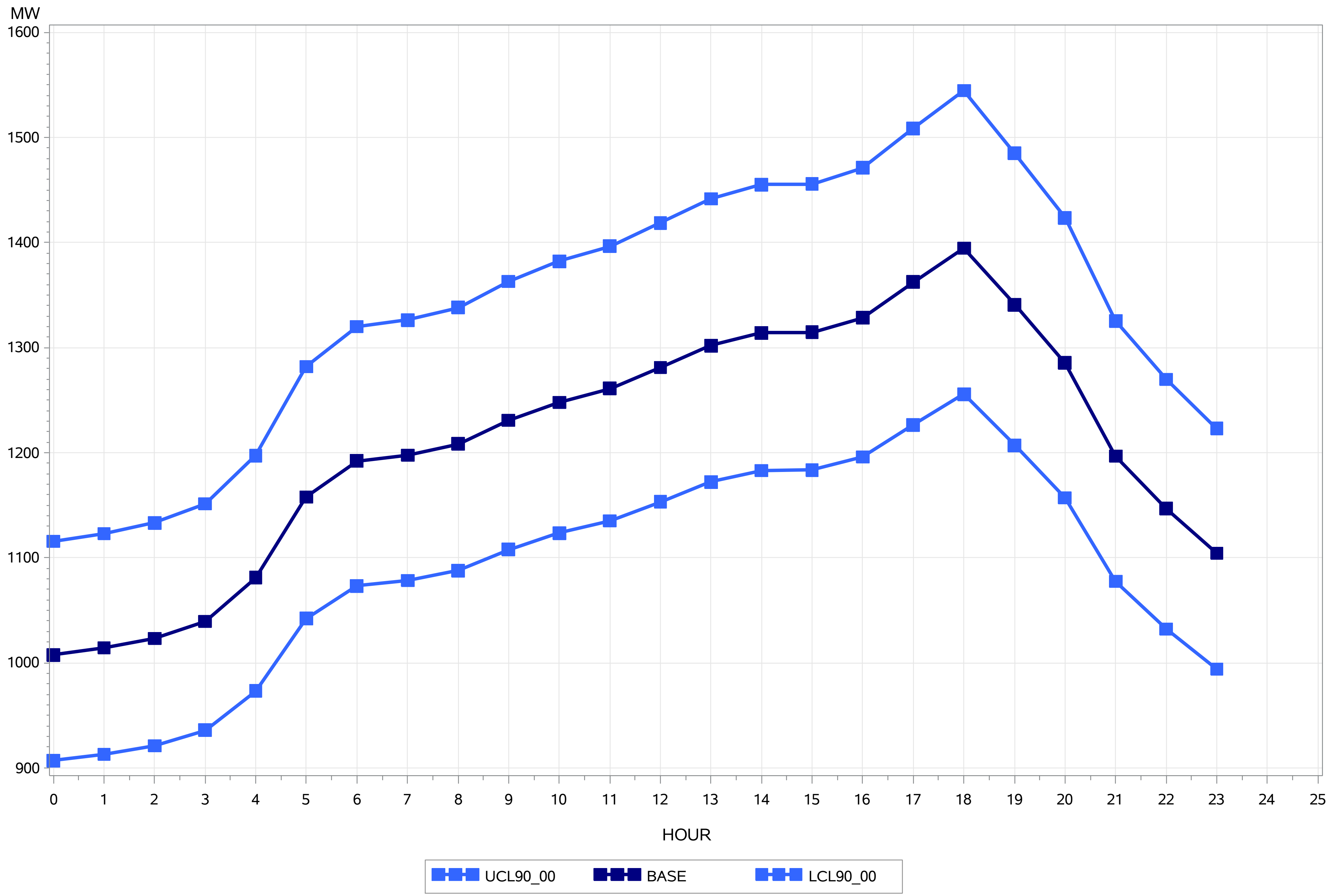
Date of On Peak Day - 09/01/2021



Member Forecasted On Peak Demand Day for October 2021

STATE OF COLORADO

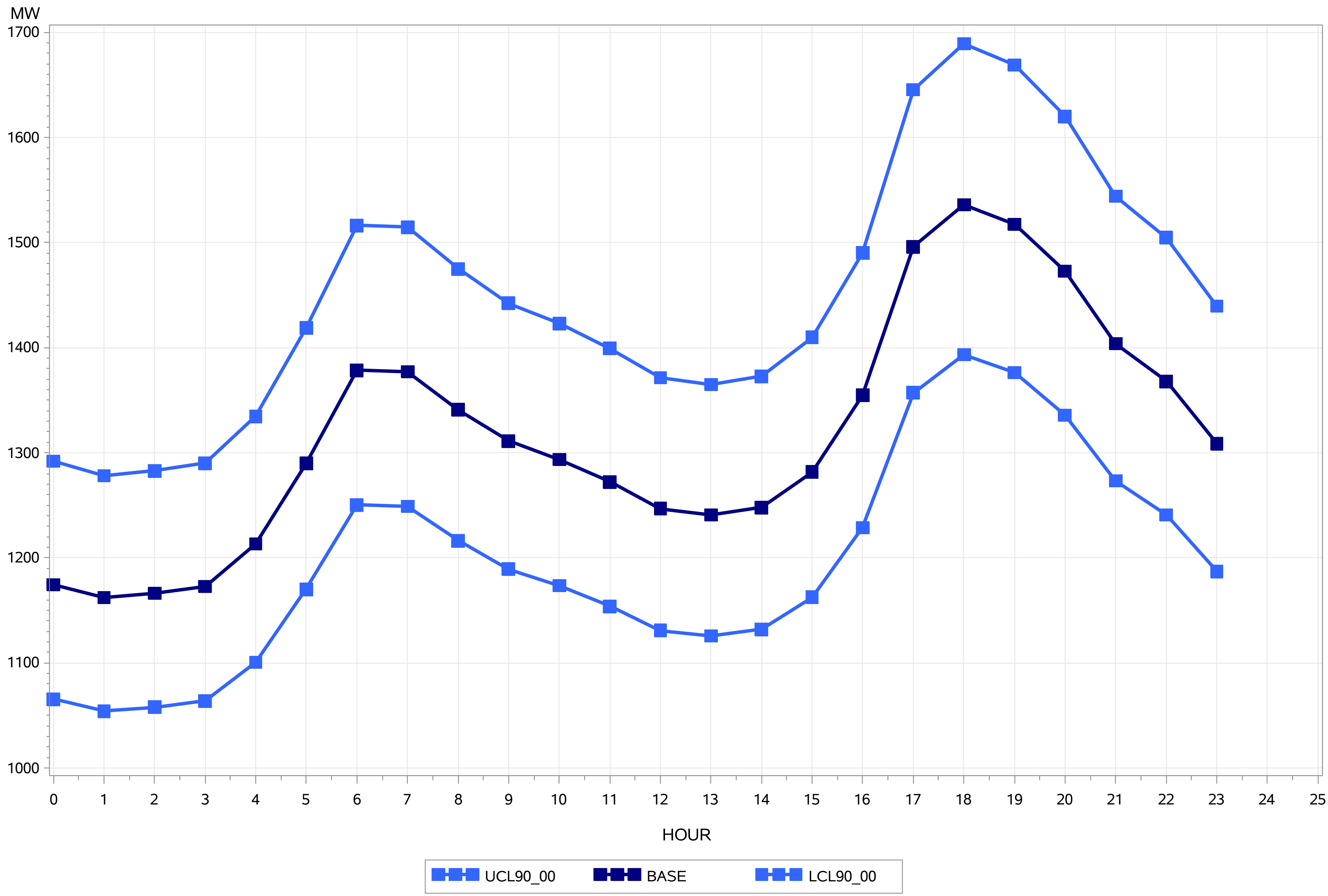
Date of On Peak Day - 10/11/2021



Member Forecasted On Peak Demand Day for November 2021

STATE OF COLORADO

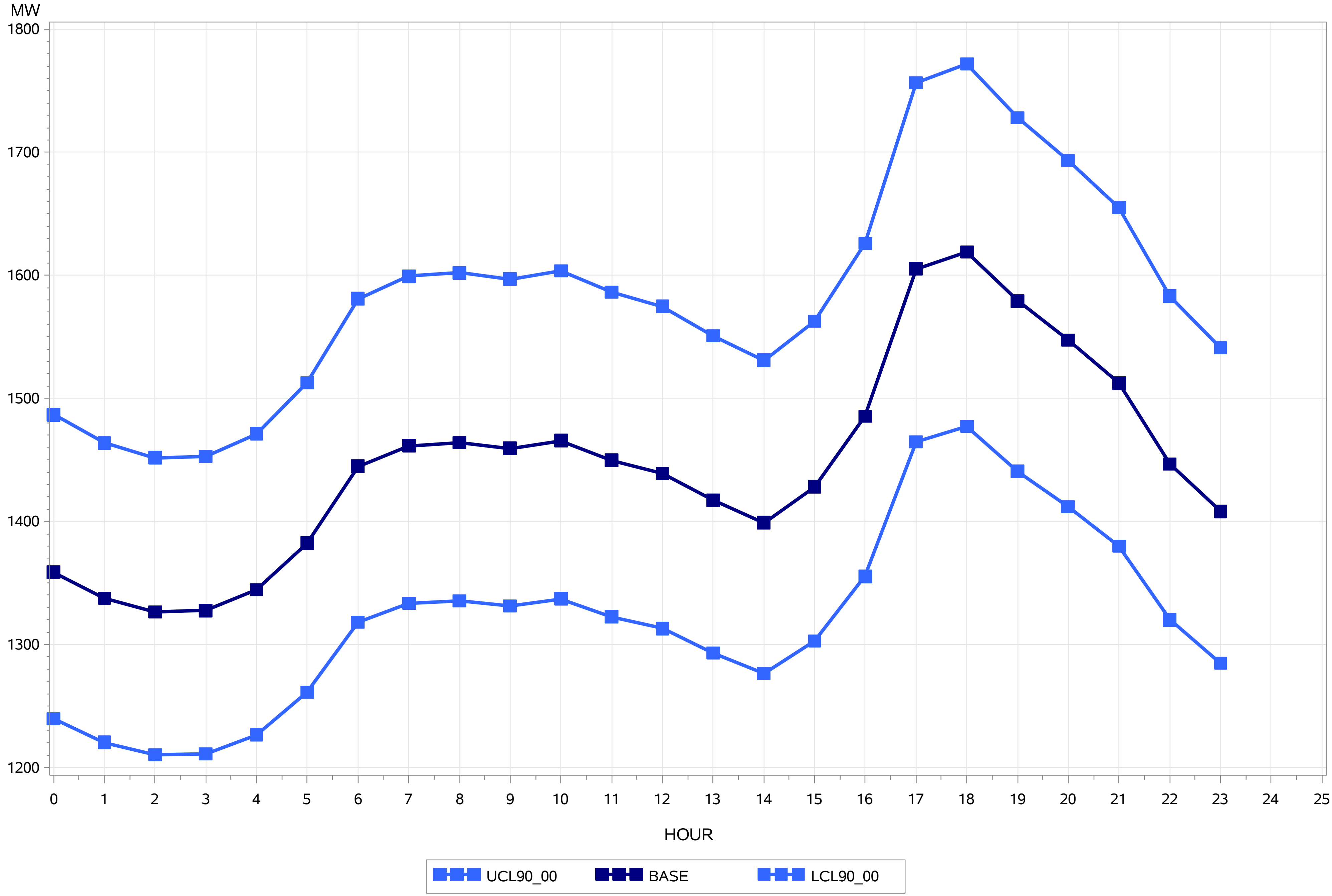
Date of On Peak Day - 11/08/2021



Member Forecasted On Peak Demand Day for December 2021

STATE OF COLORADO

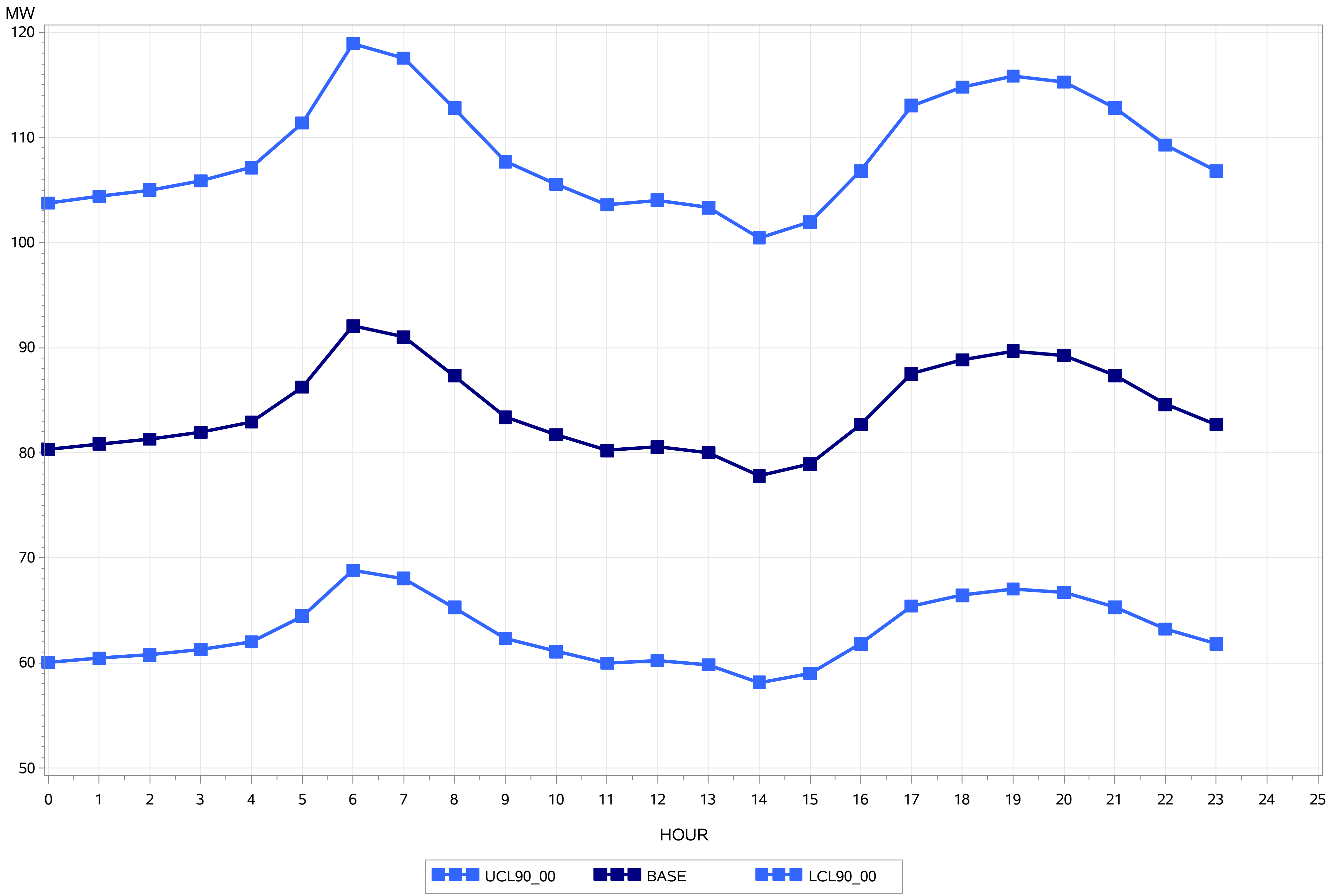
Date of On Peak Day - 12/28/2021



Member Forecasted On Peak Demand Day for January 2021

STATE OF NEBRASKA

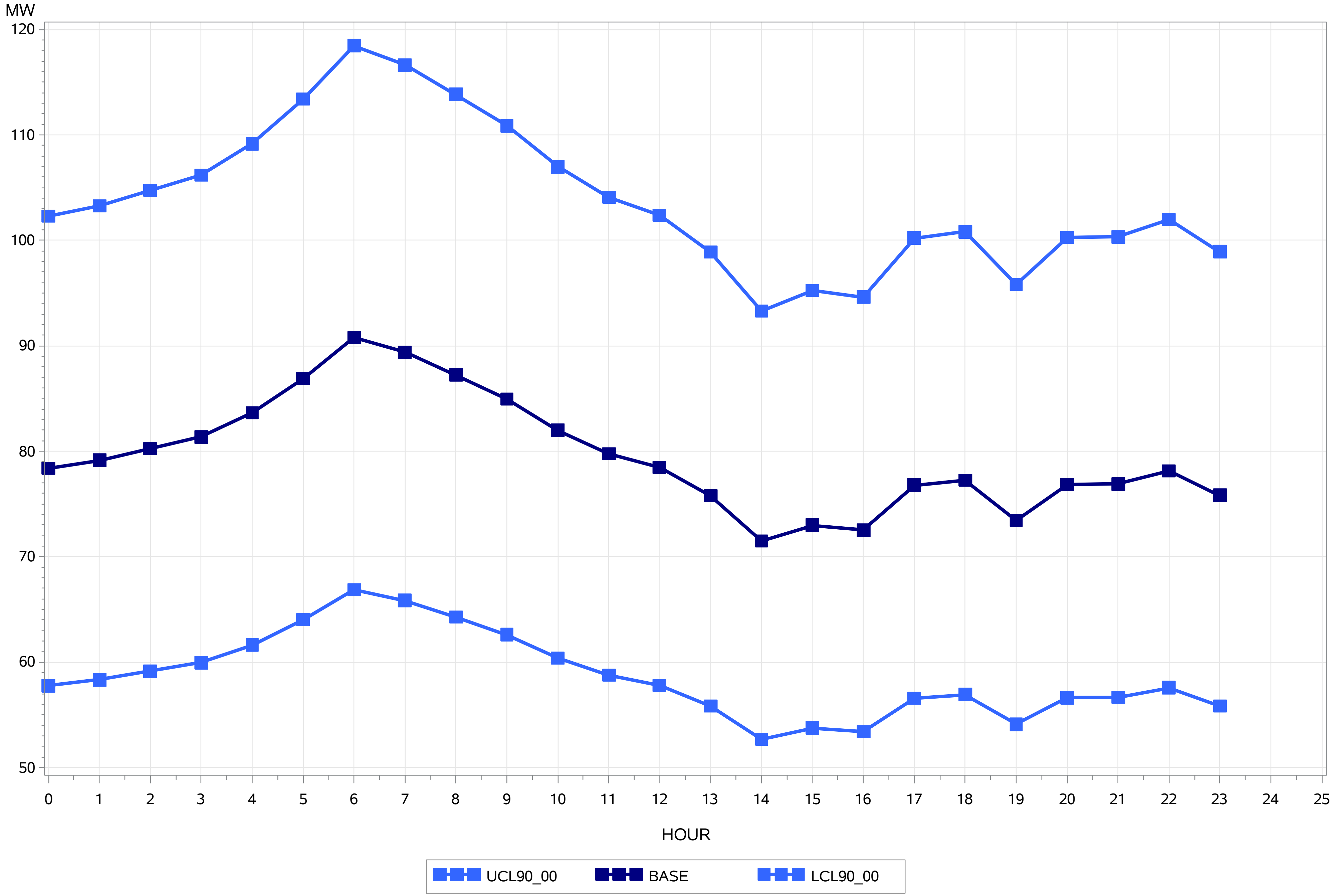
Date of On Peak Day - 01/07/2021



Member Forecasted On Peak Demand Day for February 2021

STATE OF NEBRASKA

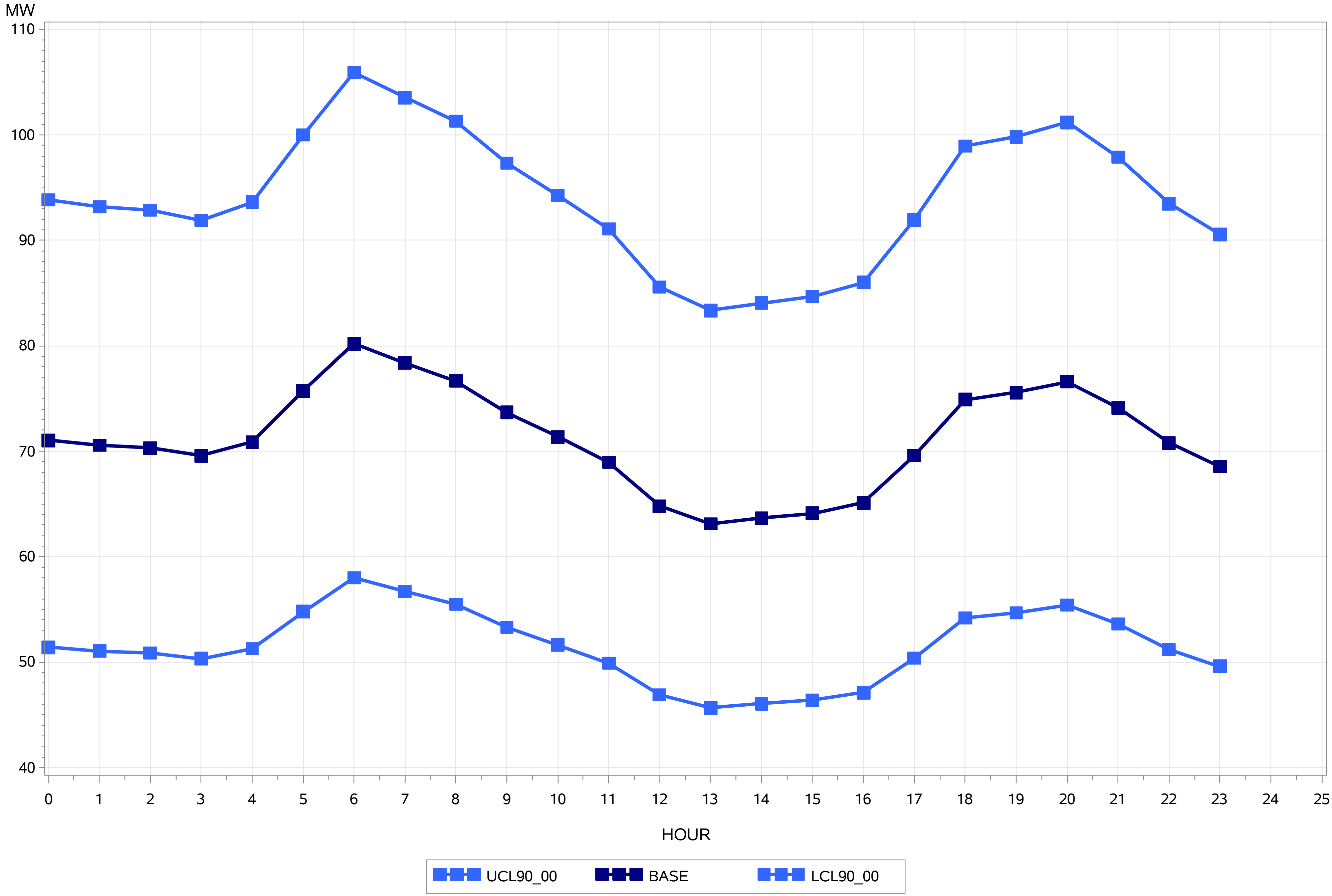
Date of On Peak Day - 02/03/2021



Member Forecasted On Peak Demand Day for March 2021

STATE OF NEBRASKA

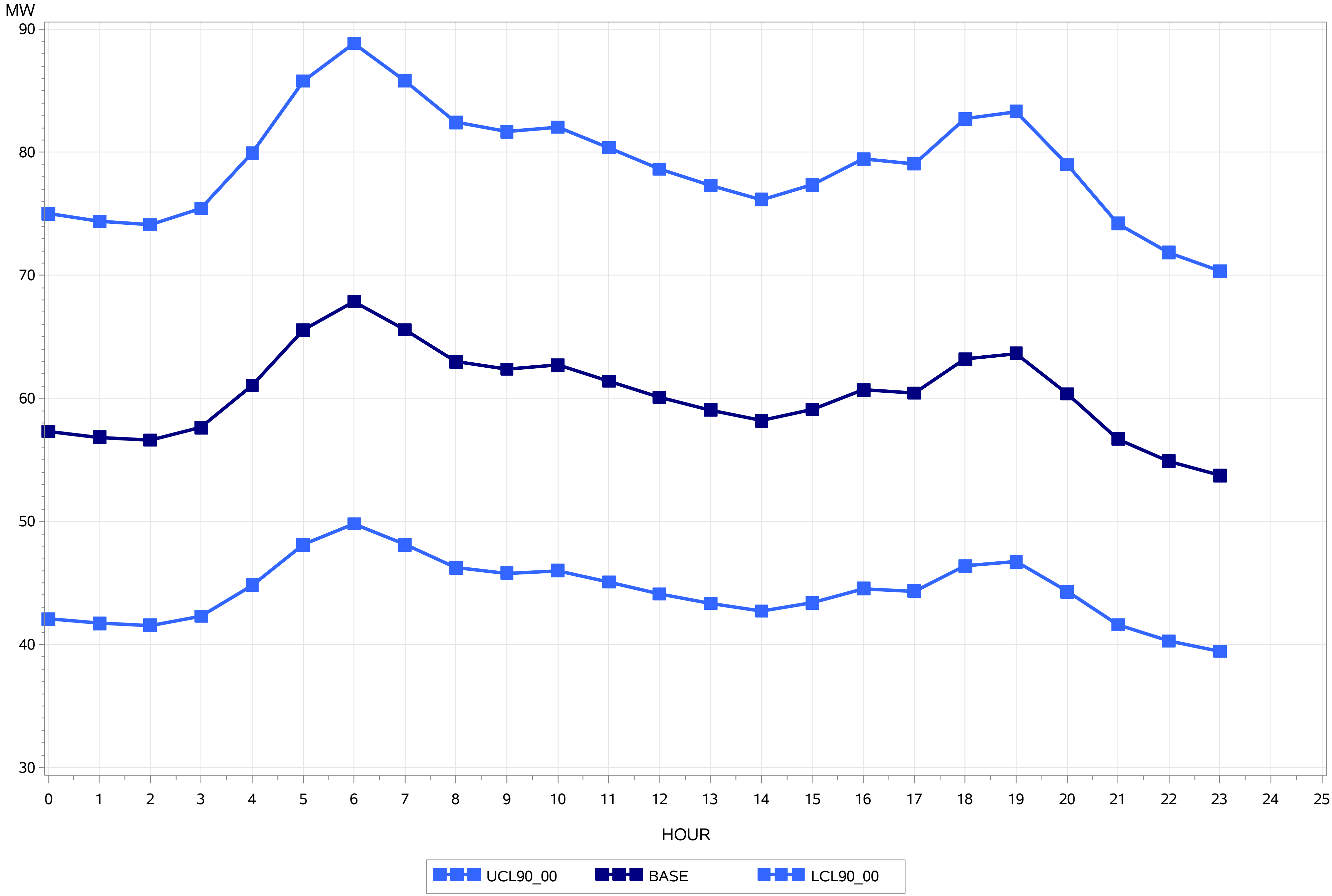
Date of On Peak Day - 03/02/2021



Member Forecasted On Peak Demand Day for April 2021

STATE OF NEBRASKA

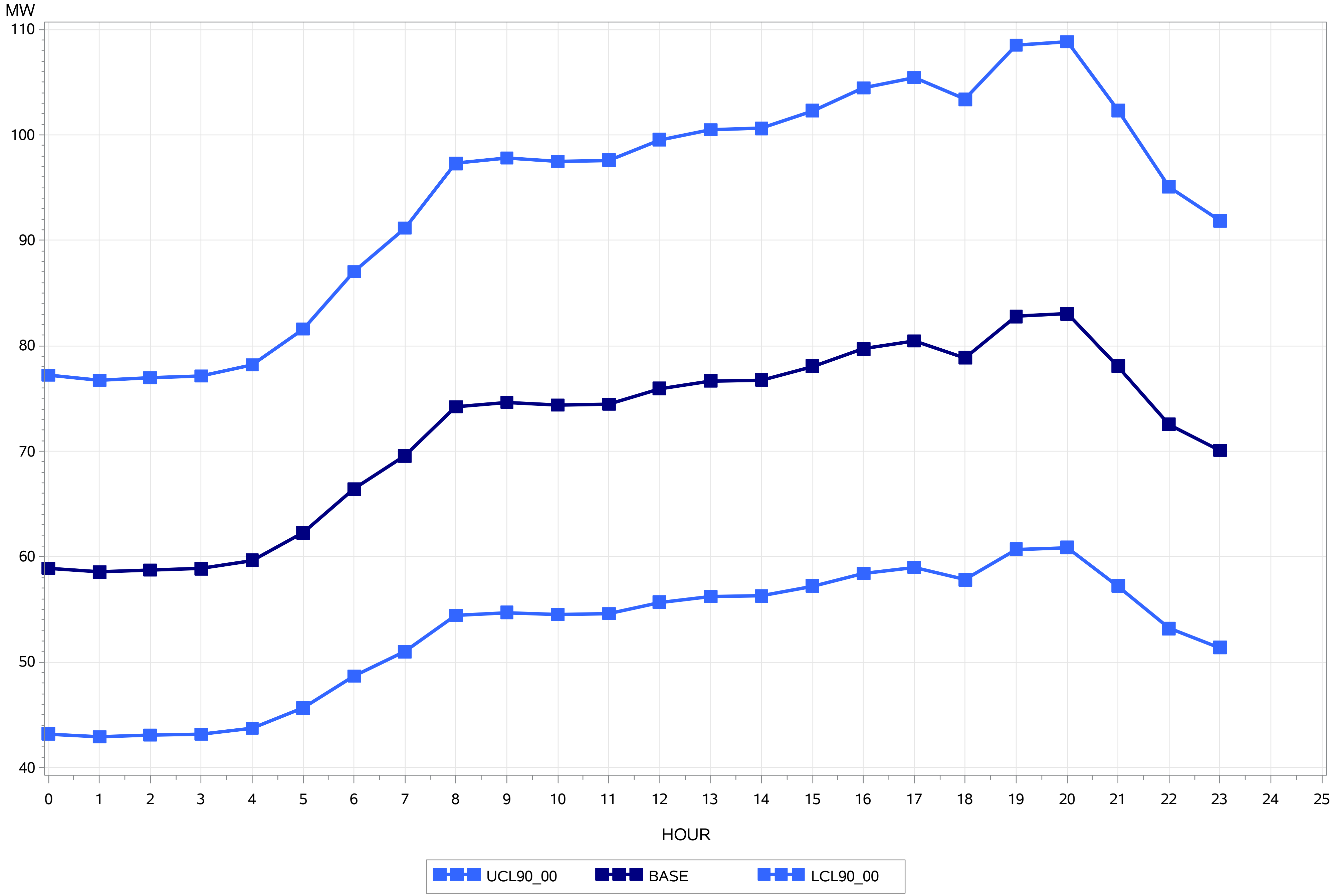
Date of On Peak Day - 04/06/2021



Member Forecasted On Peak Demand Day for May 2021

STATE OF NEBRASKA

Date of On Peak Day - 05/15/2021



Hearing Exhibit 101
PUBLIC Attachment BN-2
Proceeding No. 20A-0528E
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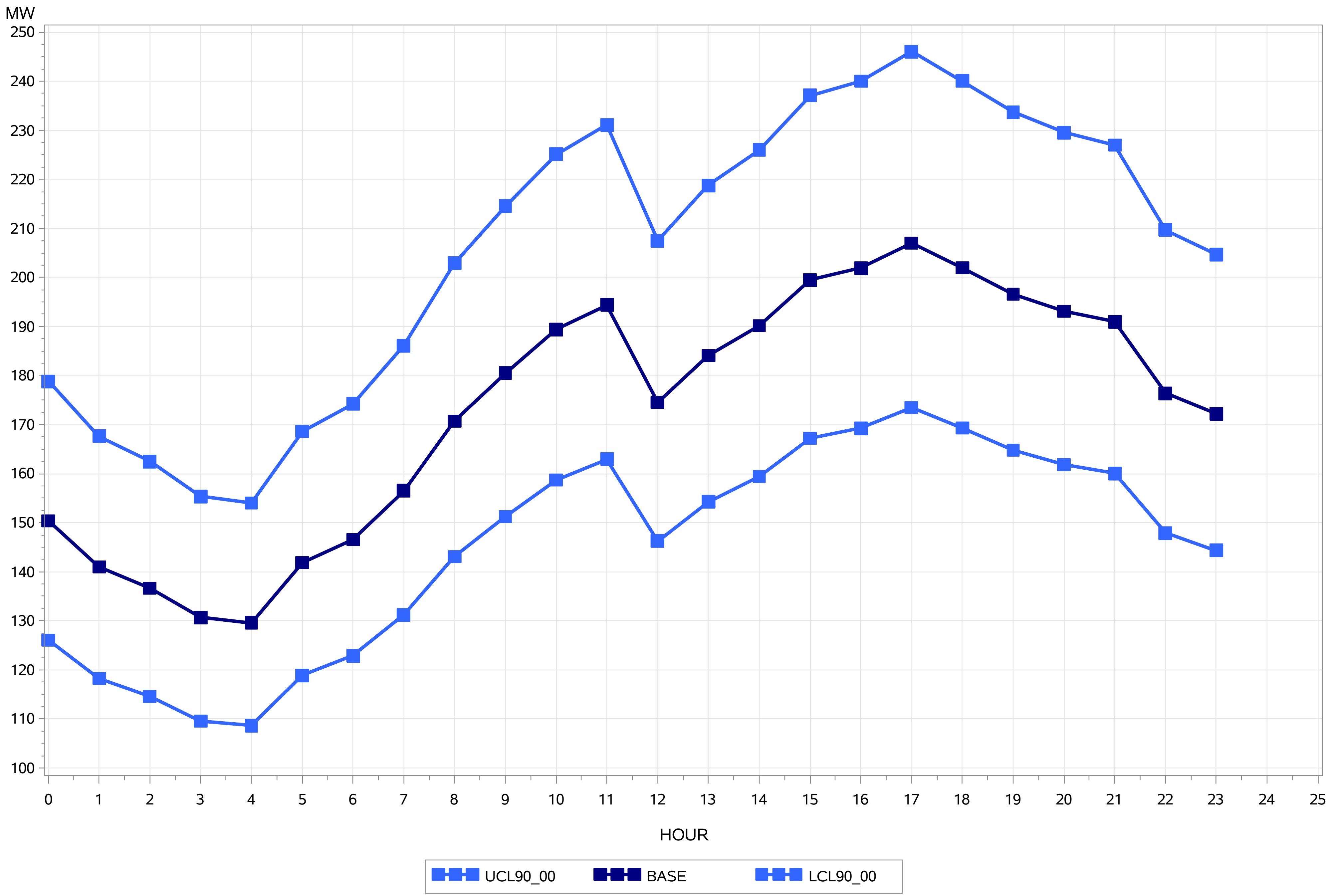
Member Forecasted On Peak Demand Day for June 2021

STATE OF NEBRASKA

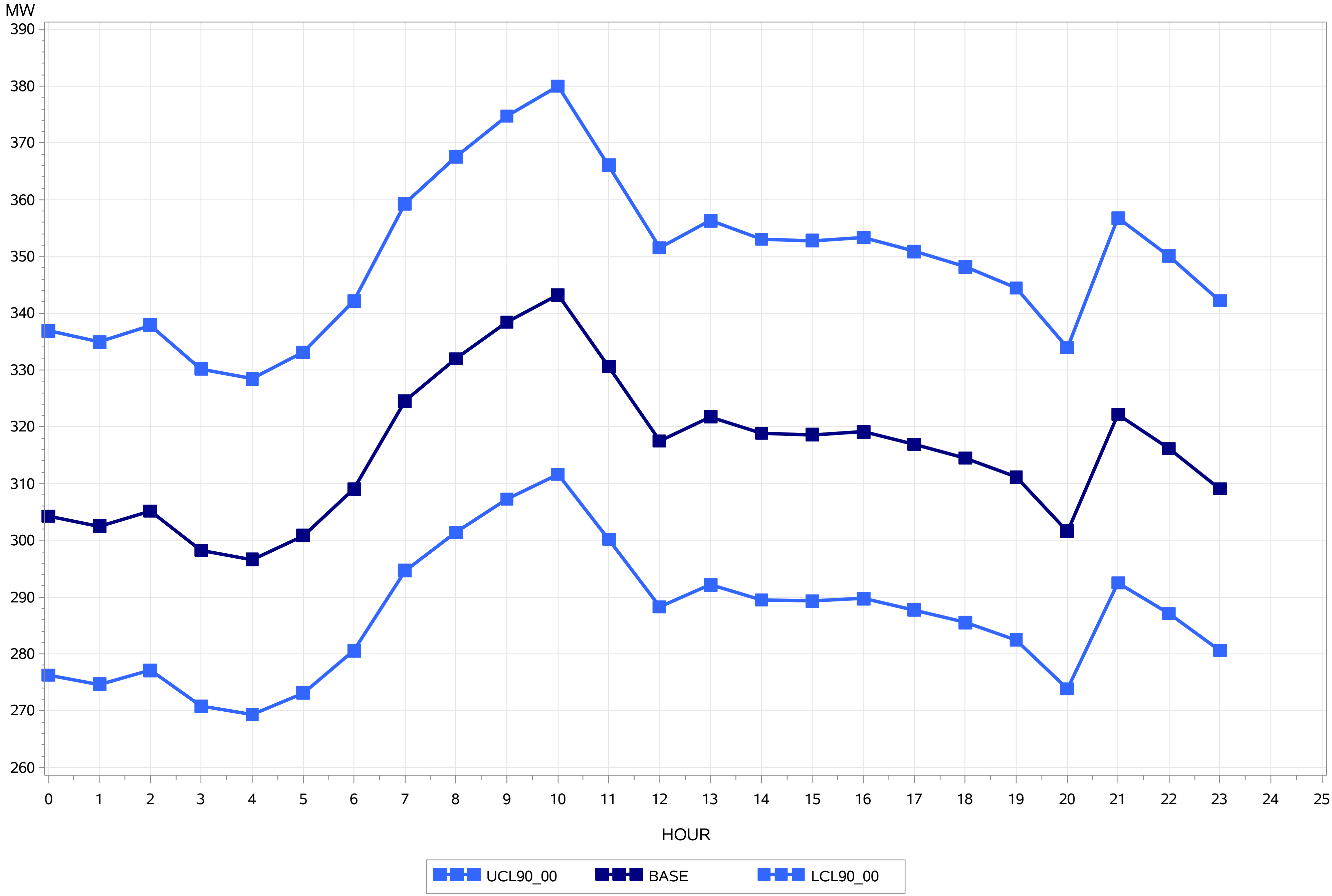
Date of On Peak Day - 06/11/2021



Member Forecasted On Peak Demand Day for July 2021

STATE OF NEBRASKA

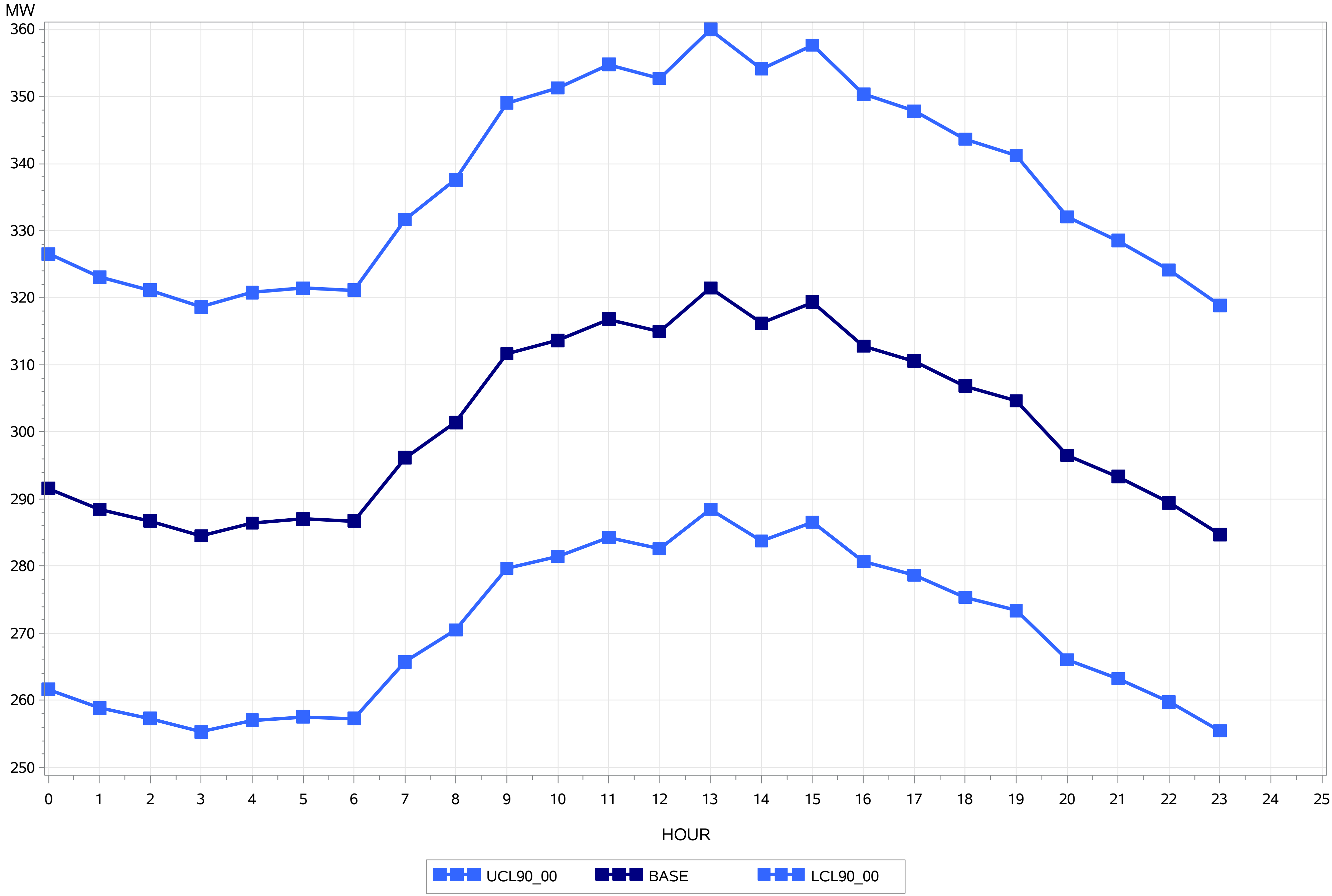
Date of On Peak Day - 07/14/2021



Member Forecasted On Peak Demand Day for August 2021

STATE OF NEBRASKA

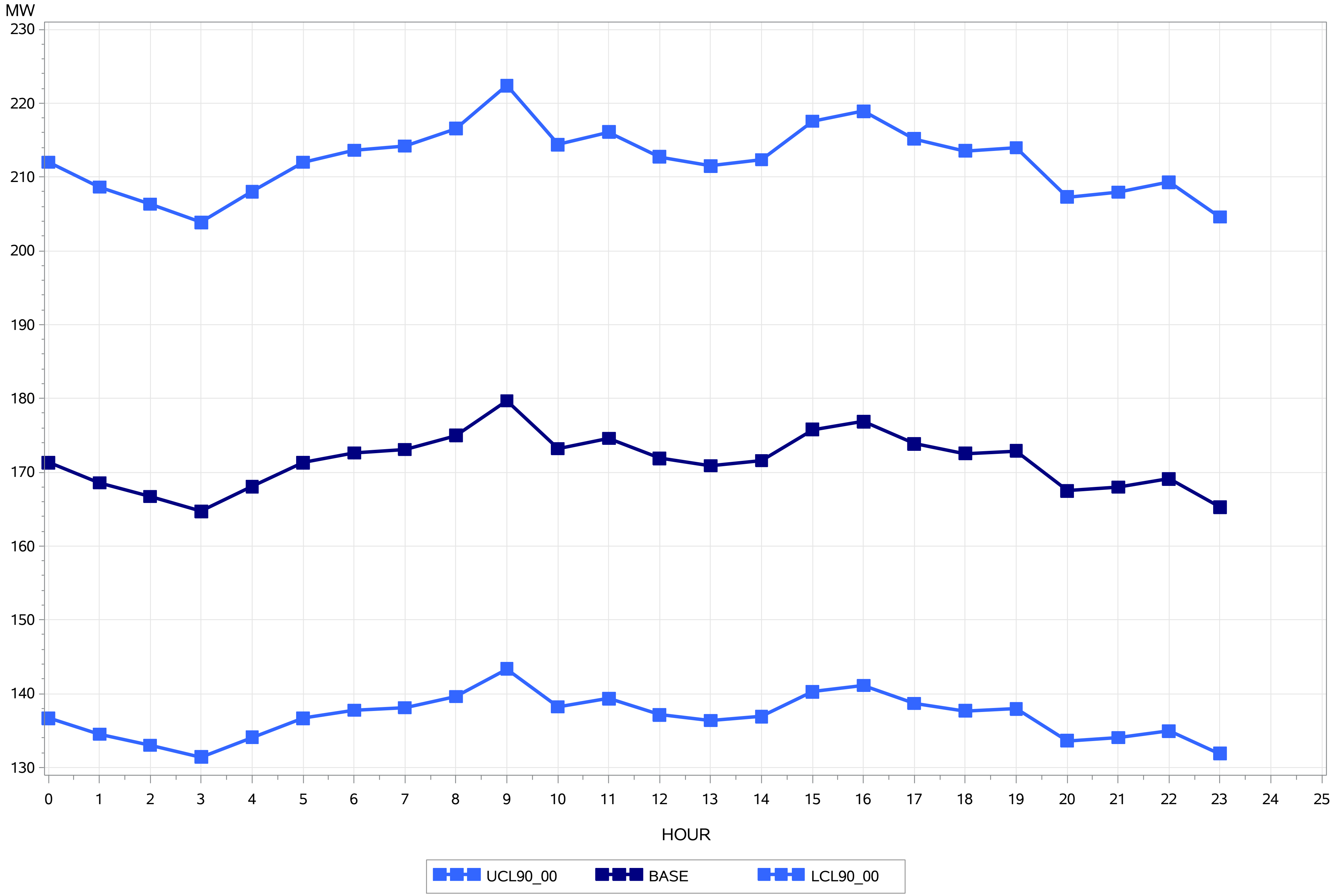
Date of On Peak Day - 08/24/2021



Member Forecasted On Peak Demand Day for September 2021

STATE OF NEBRASKA

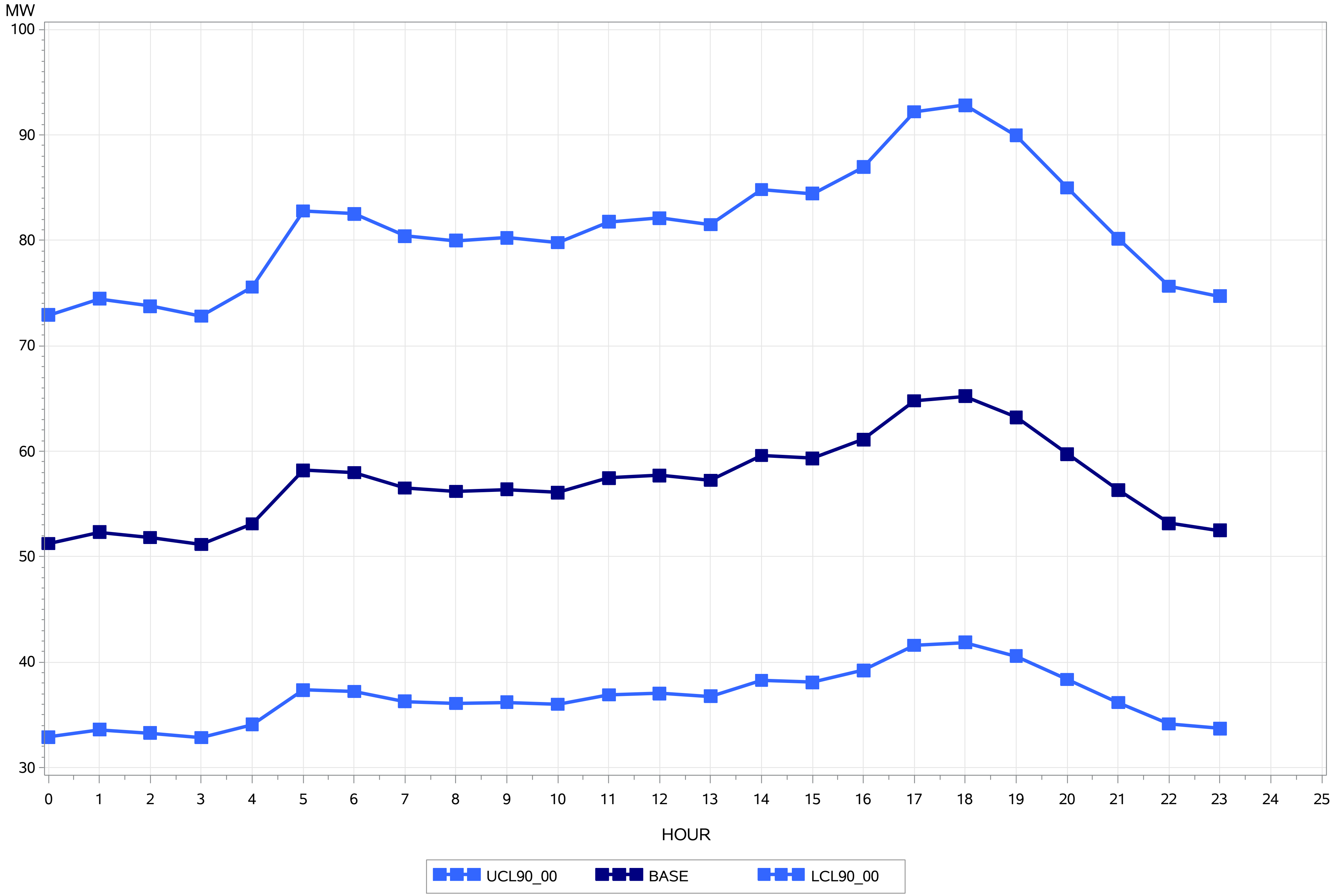
Date of On Peak Day - 09/01/2021



Member Forecasted On Peak Demand Day for October 2021

STATE OF NEBRASKA

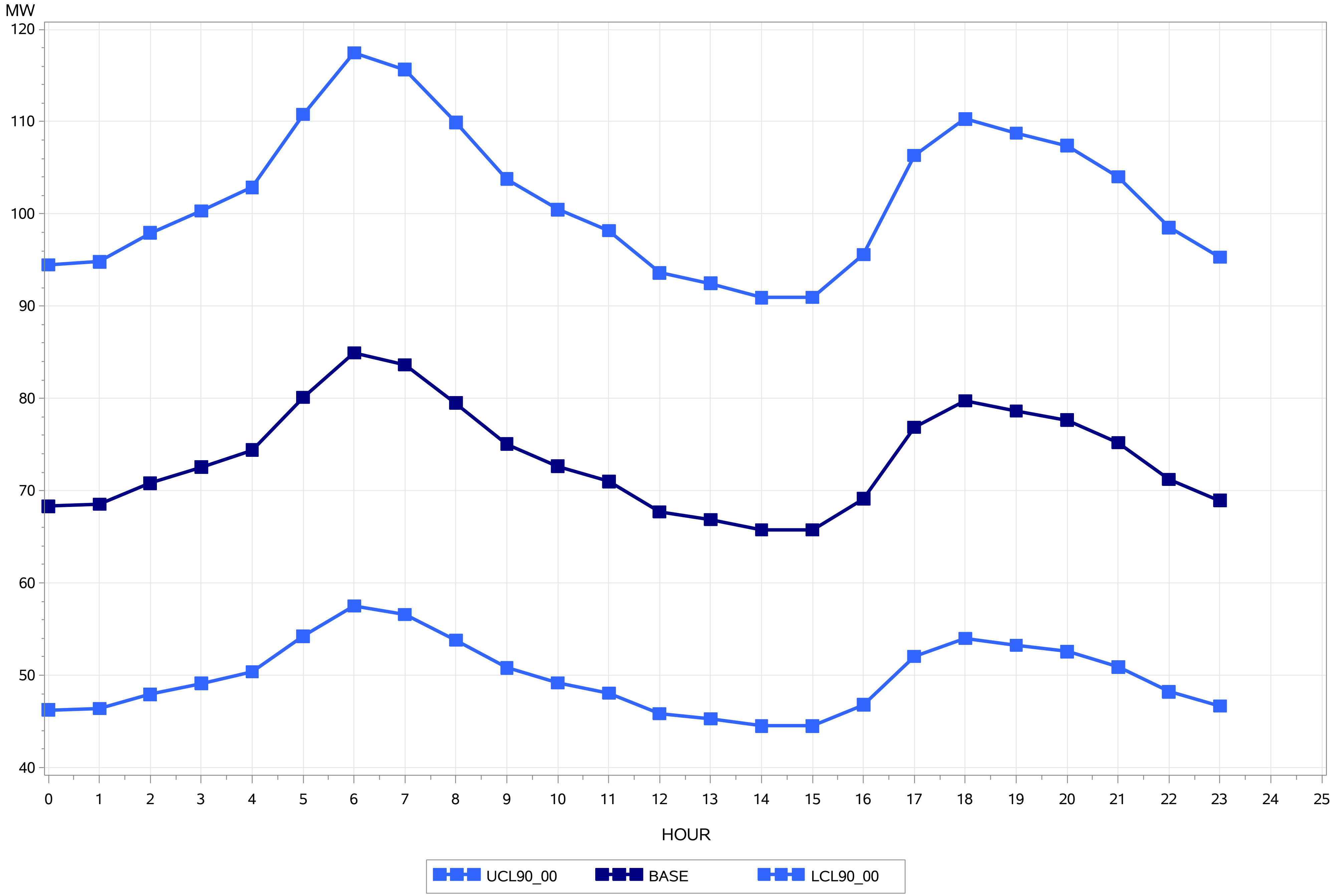
Date of On Peak Day - 10/13/2021



Member Forecasted On Peak Demand Day for November 2021

STATE OF NEBRASKA

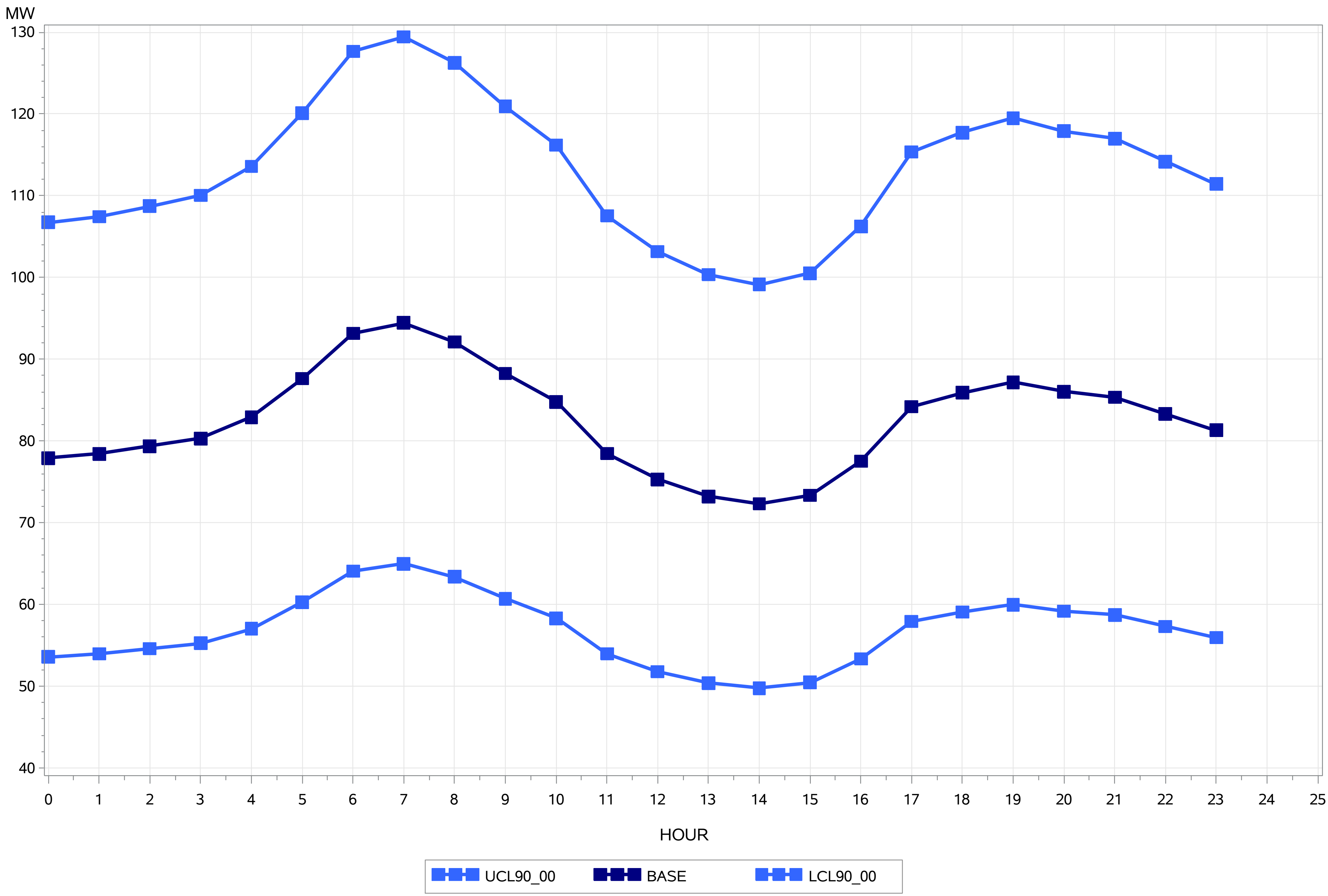
Date of On Peak Day - 11/09/2021



Member Forecasted On Peak Demand Day for December 2021

STATE OF NEBRASKA

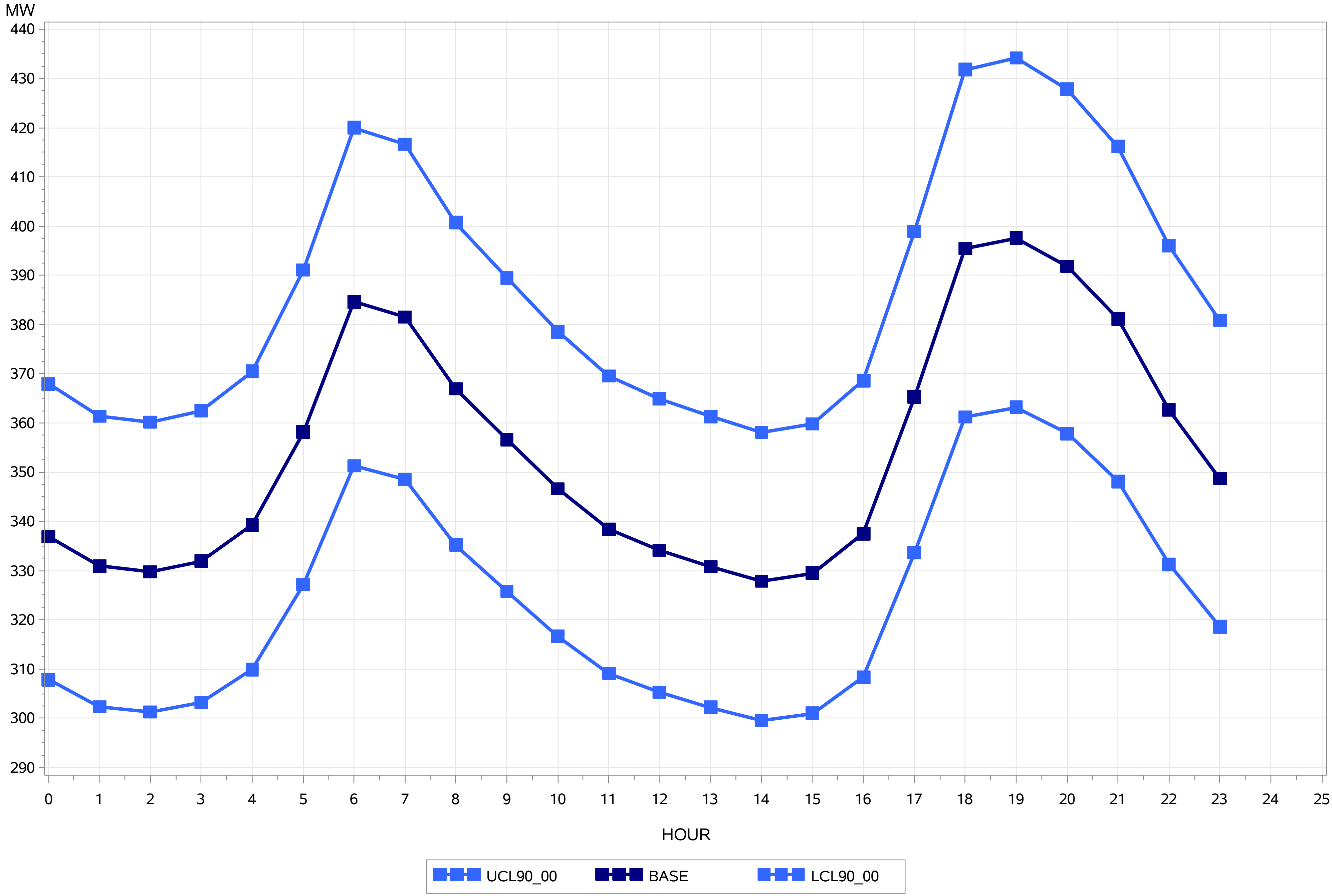
Date of On Peak Day - 12/30/2021



Member Forecasted On Peak Demand Day for January 2021

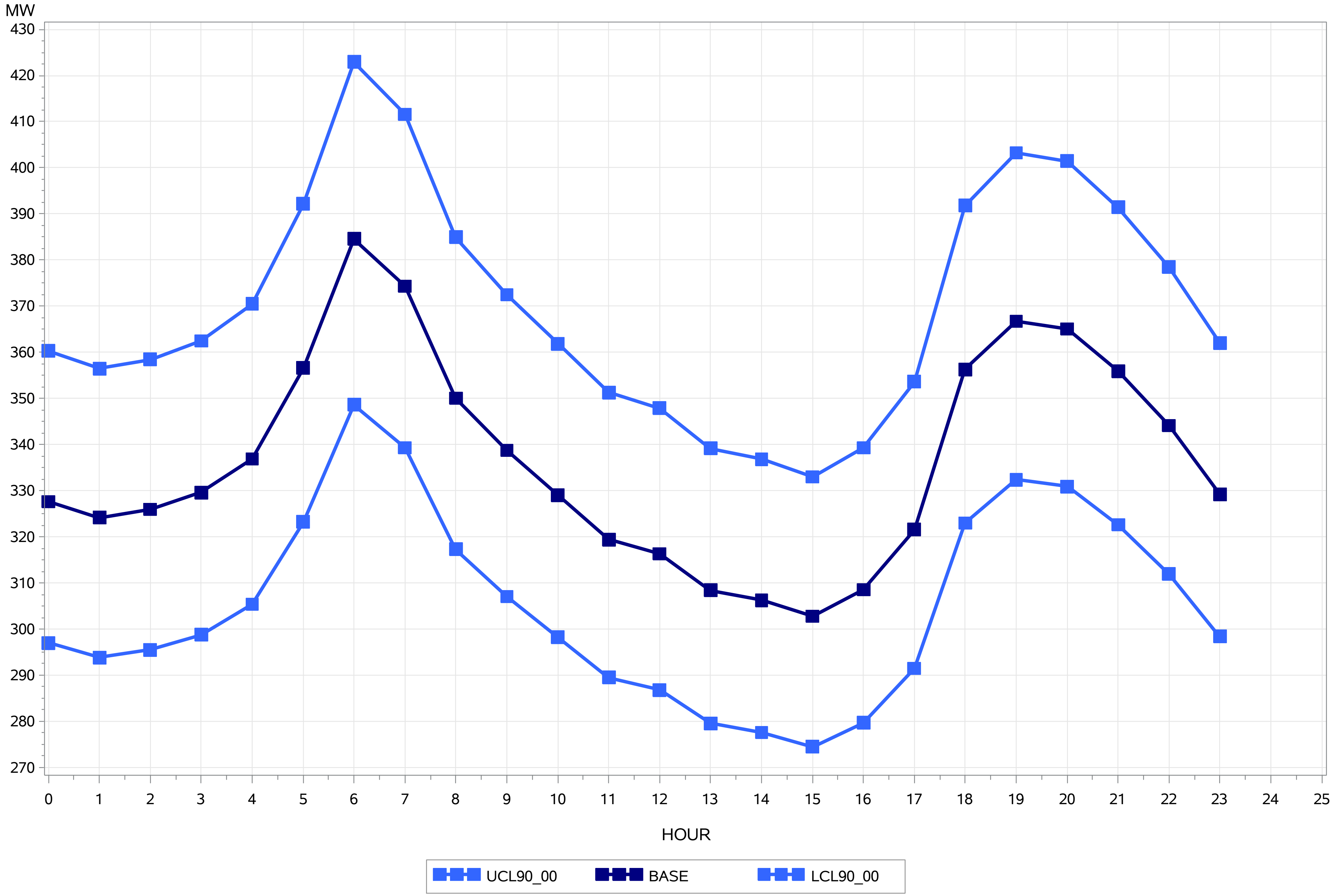
STATE OF NEW MEXICO

Date of On Peak Day - 01/26/2021



PUBLIC

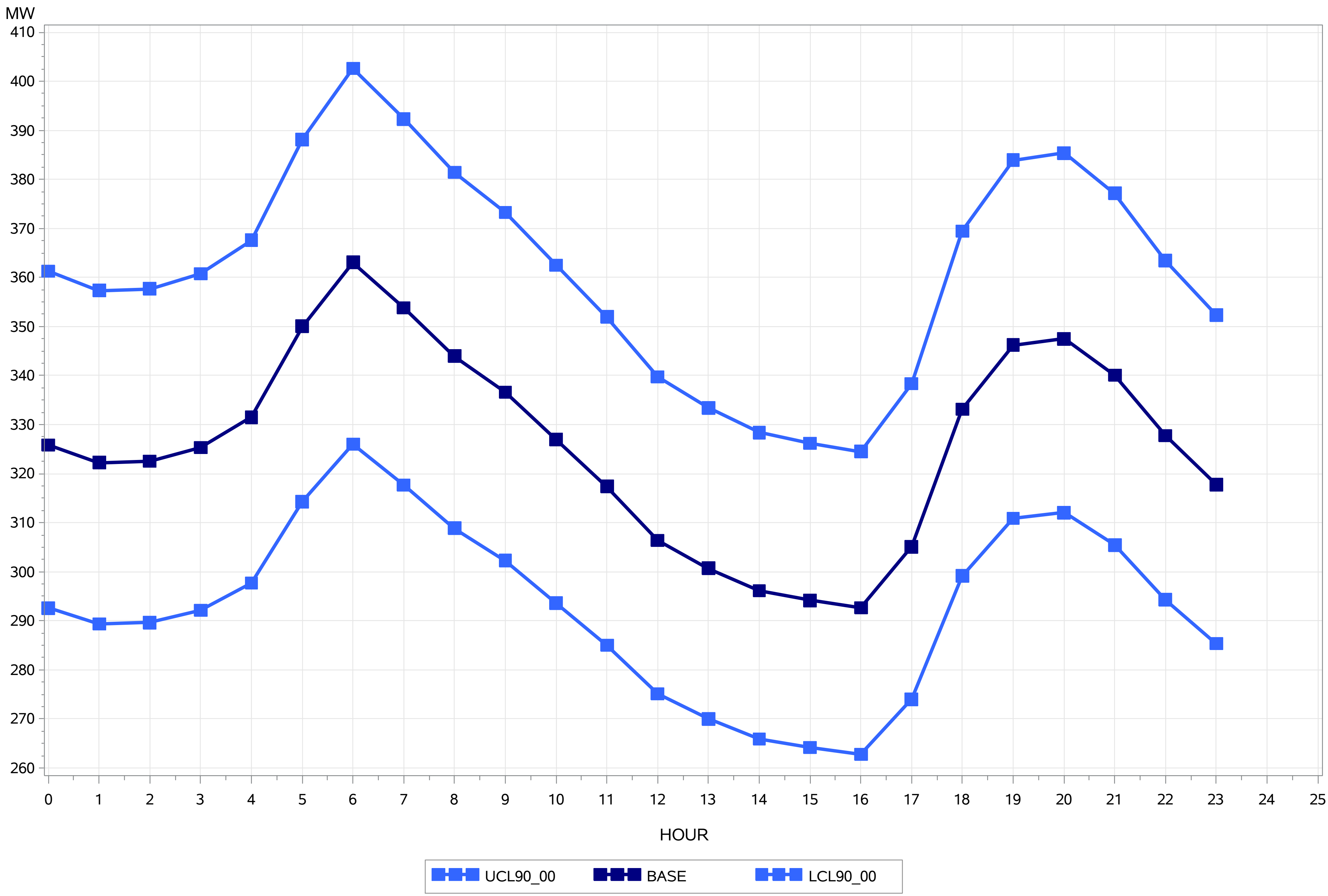
Member Forecasted On Peak Demand Day for February 2021
STATE OF NEW MEXICO
Date of On Peak Day - 02/25/2021



Member Forecasted On Peak Demand Day for March 2021

STATE OF NEW MEXICO

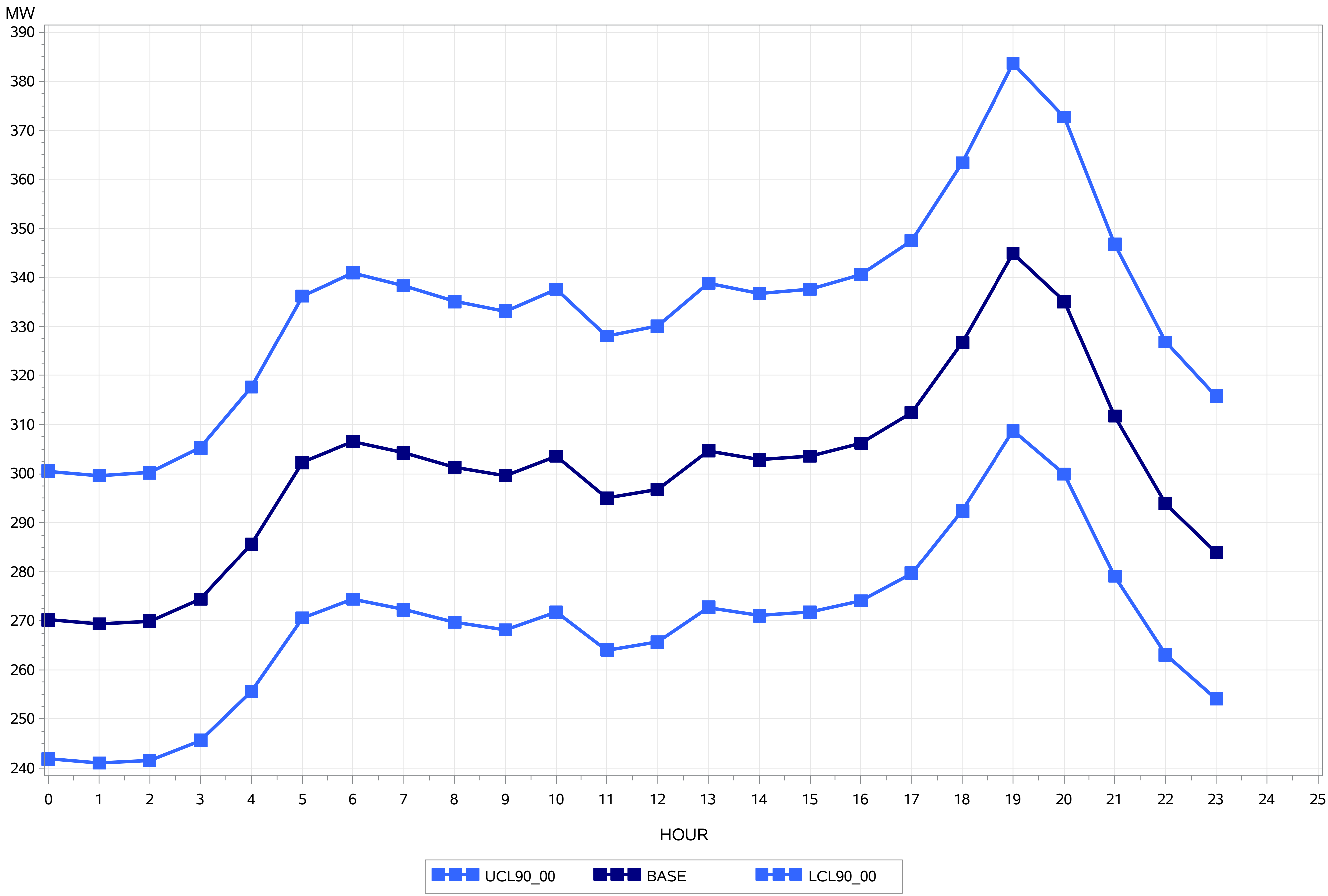
Date of On Peak Day - 03/02/2021



Member Forecasted On Peak Demand Day for April 2021

STATE OF NEW MEXICO

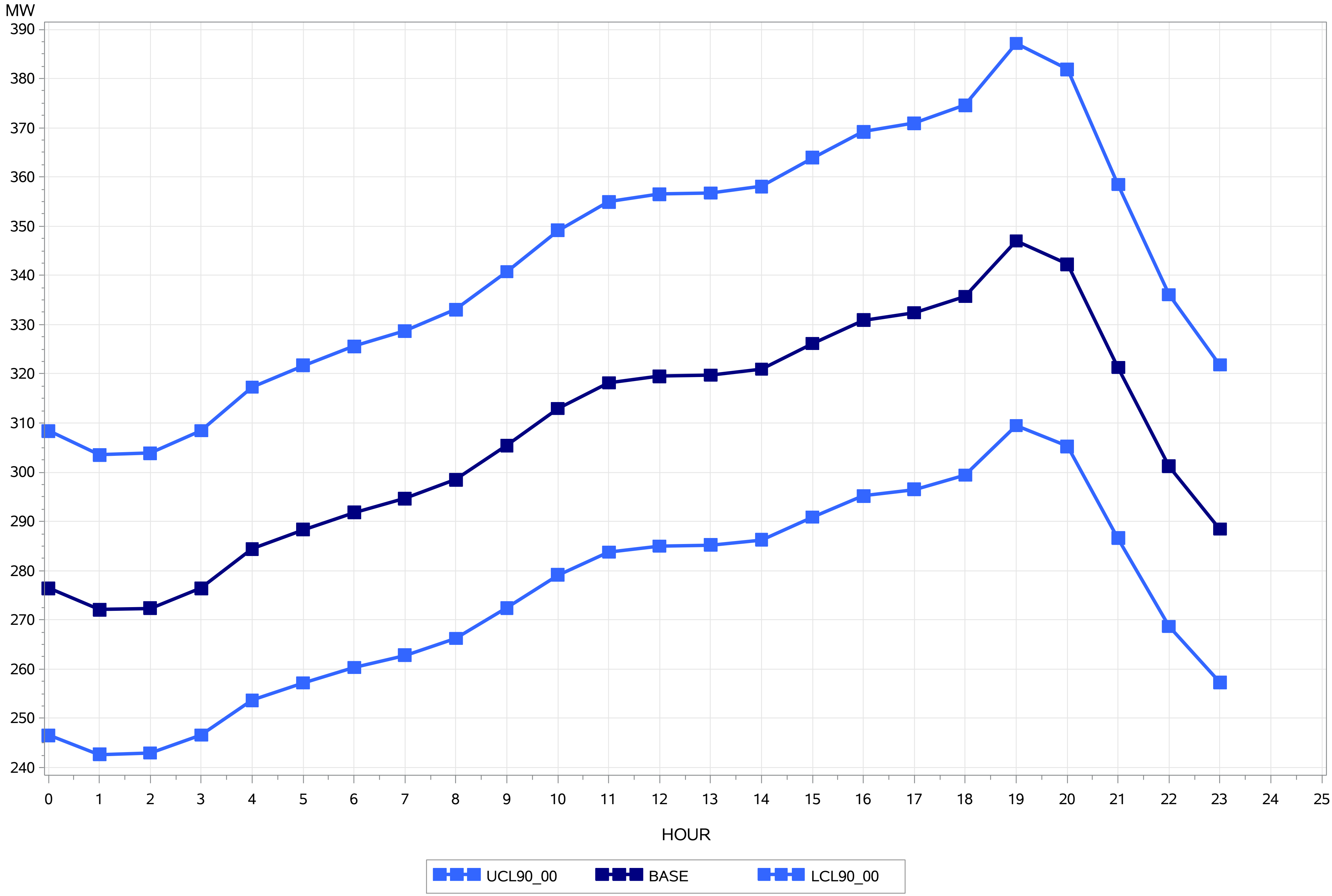
Date of On Peak Day - 04/12/2021



Member Forecasted On Peak Demand Day for May 2021

STATE OF NEW MEXICO

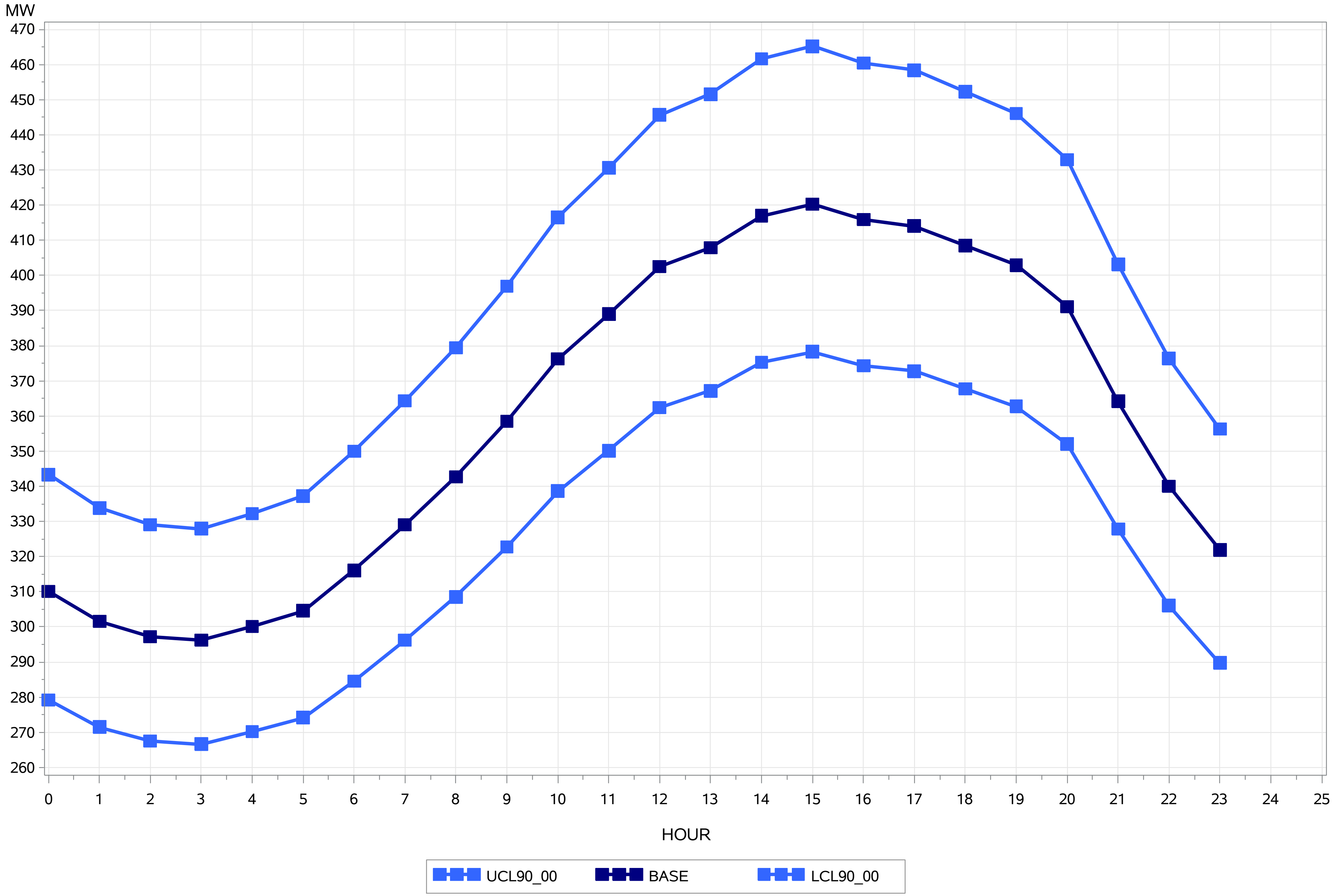
Date of On Peak Day - 05/26/2021



Member Forecasted On Peak Demand Day for June 2021

STATE OF NEW MEXICO

Date of On Peak Day - 06/24/2021

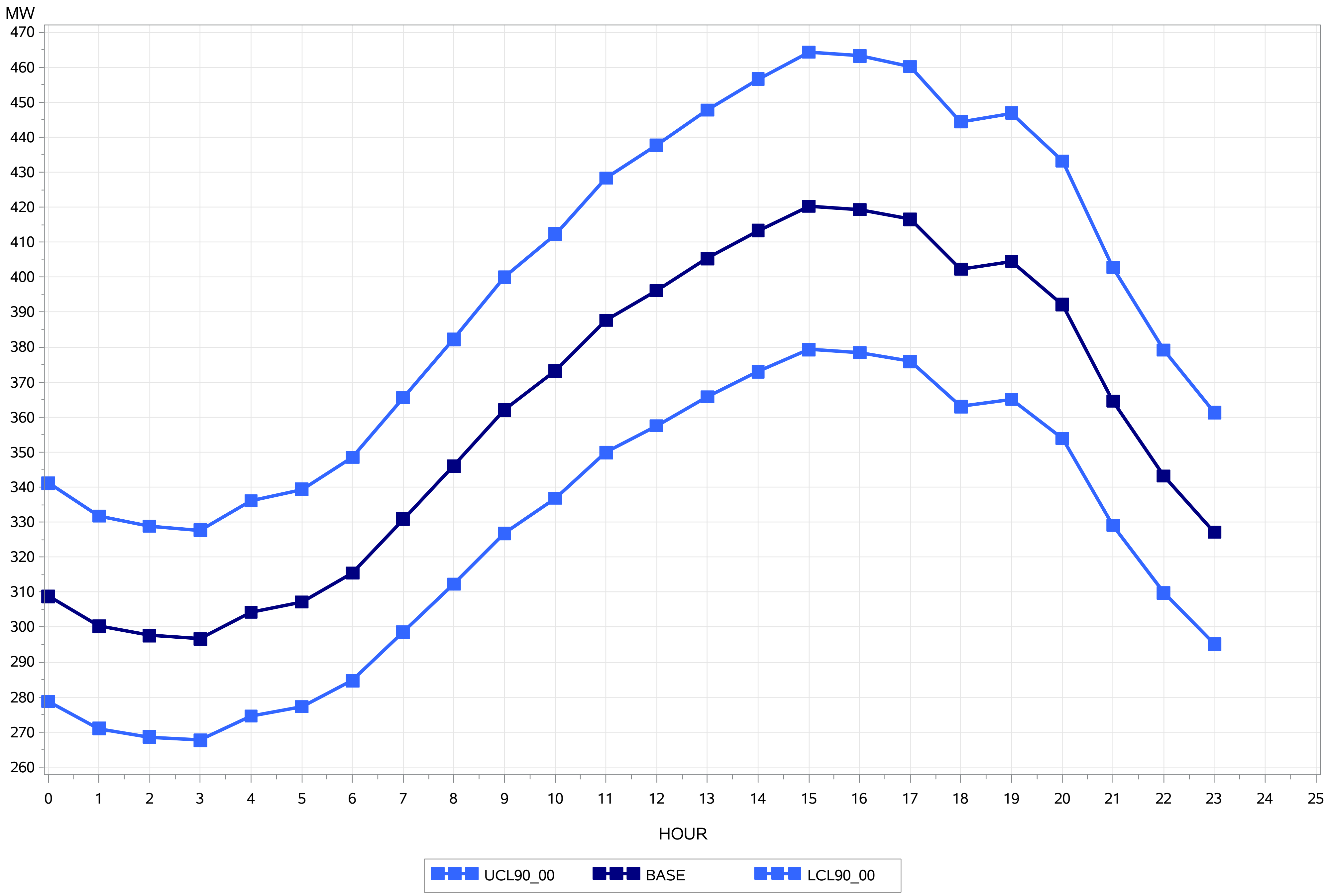


PUBLIC

Member Forecasted On Peak Demand Day for July 2021

STATE OF NEW MEXICO

Date of On Peak Day - 07/22/2021

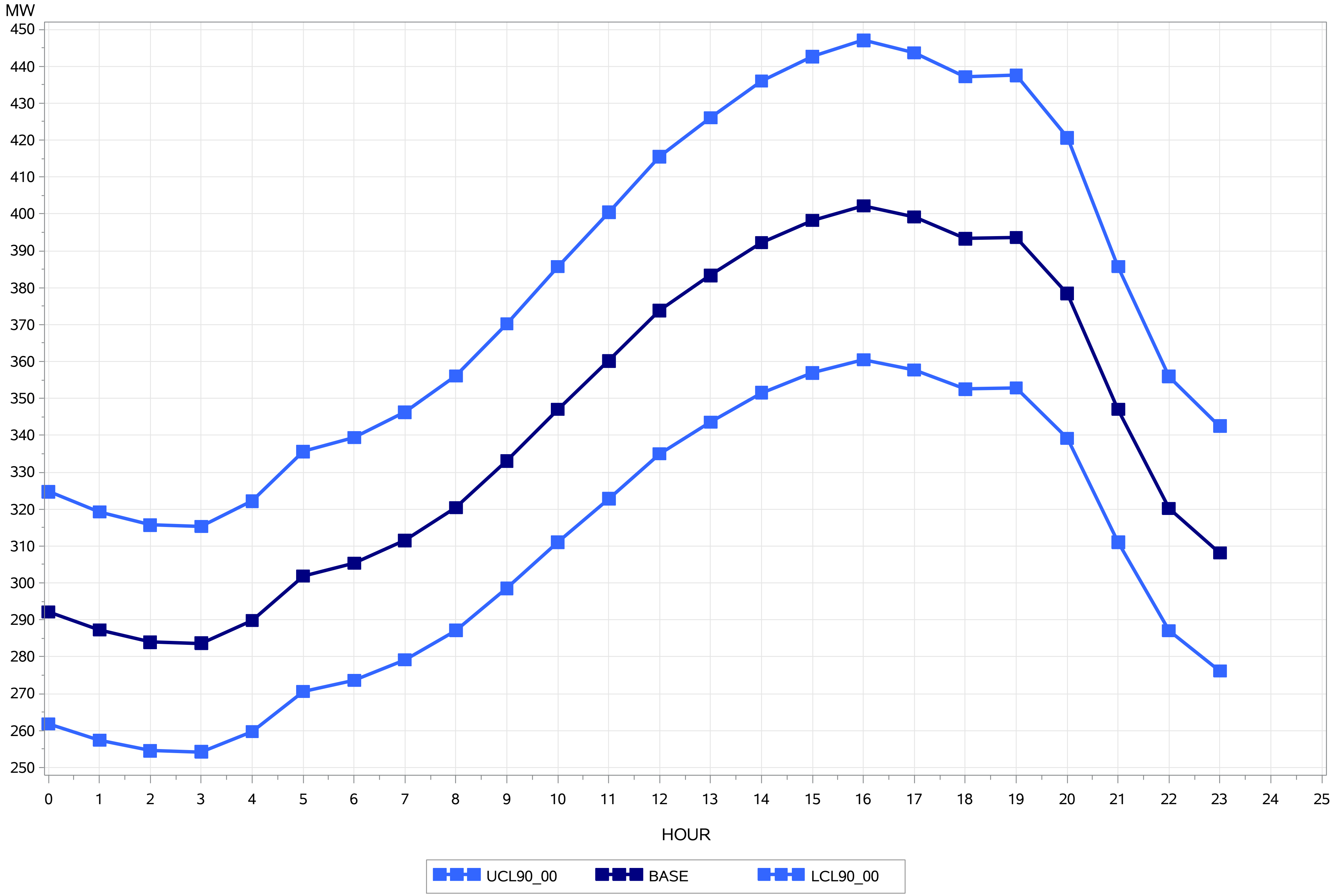


PUBLIC

Member Forecasted On Peak Demand Day for August 2021

STATE OF NEW MEXICO

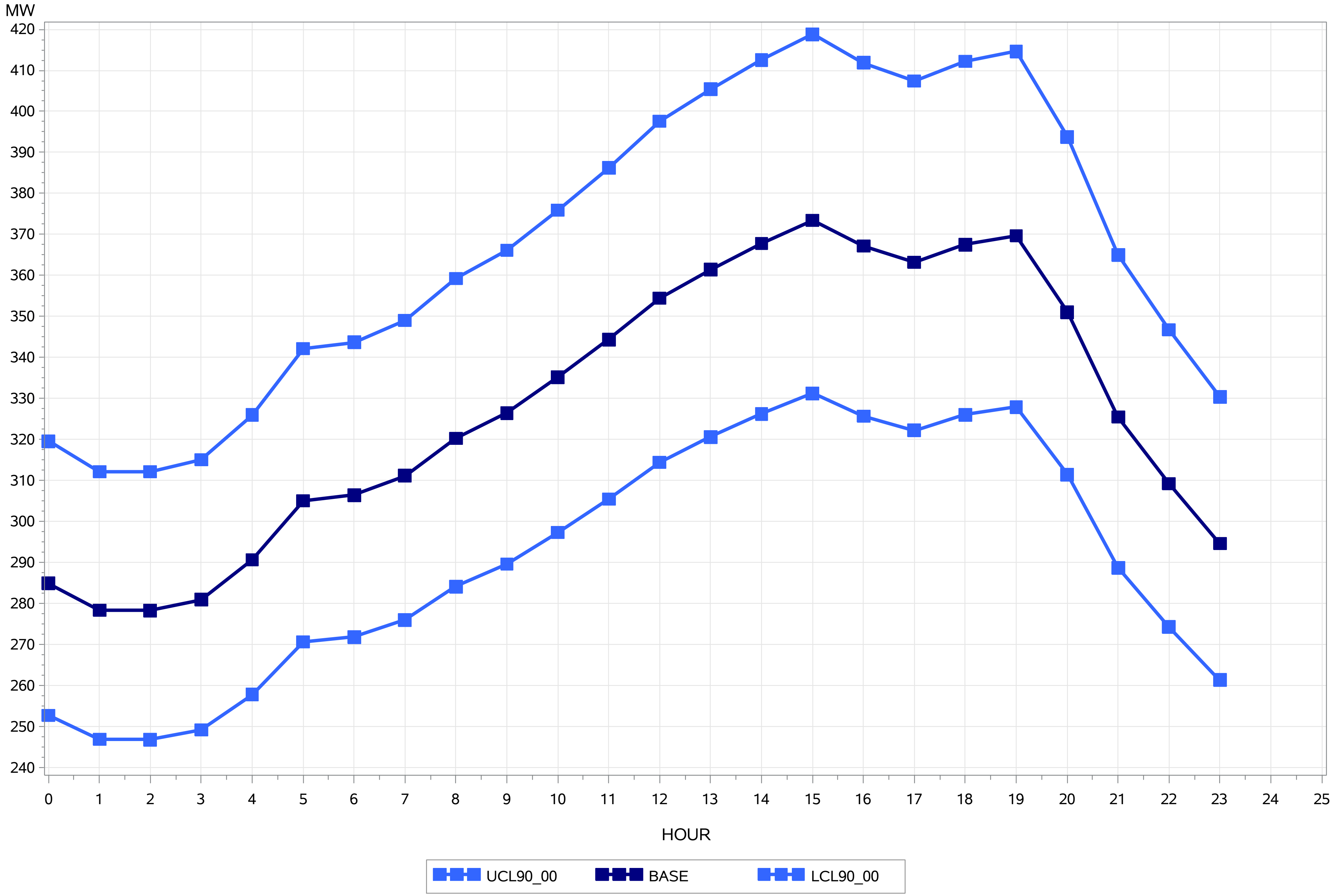
Date of On Peak Day - 08/18/2021



Member Forecasted On Peak Demand Day for September 2021

STATE OF NEW MEXICO

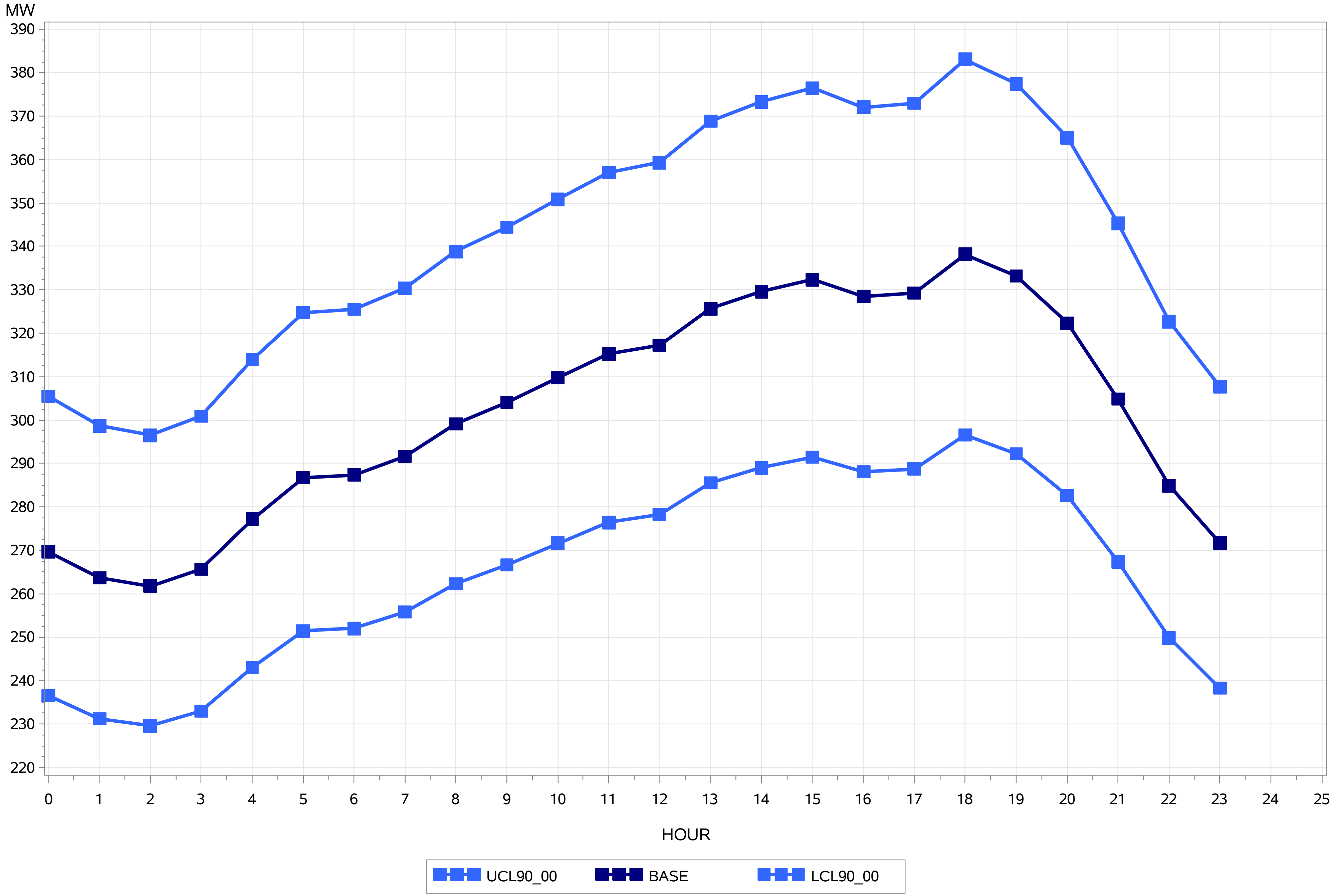
Date of On Peak Day - 09/08/2021



Member Forecasted On Peak Demand Day for October 2021

STATE OF NEW MEXICO

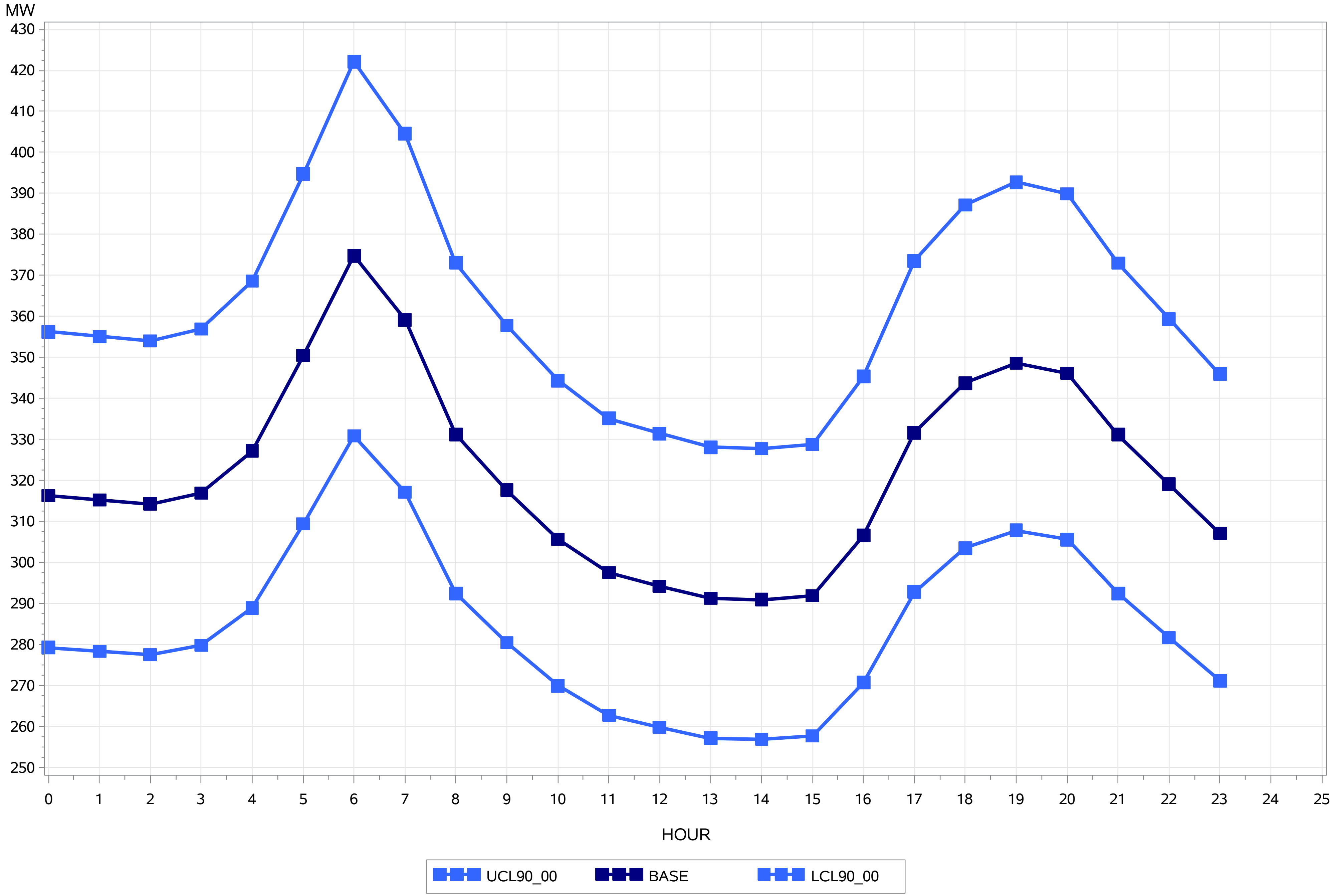
Date of On Peak Day - 10/01/2021



Member Forecasted On Peak Demand Day for November 2021

STATE OF NEW MEXICO

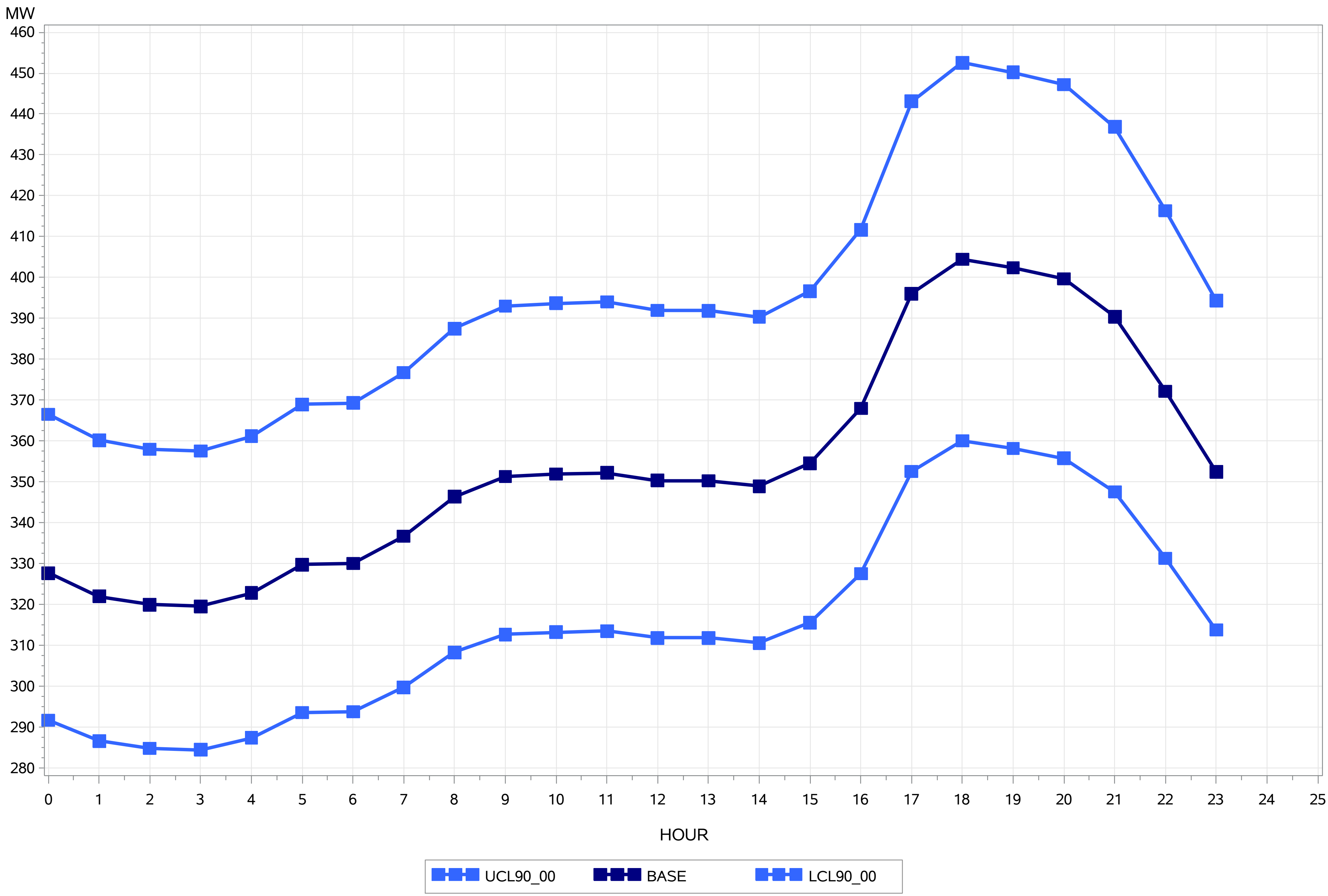
Date of On Peak Day - 11/16/2021



Member Forecasted On Peak Demand Day for December 2021

STATE OF NEW MEXICO

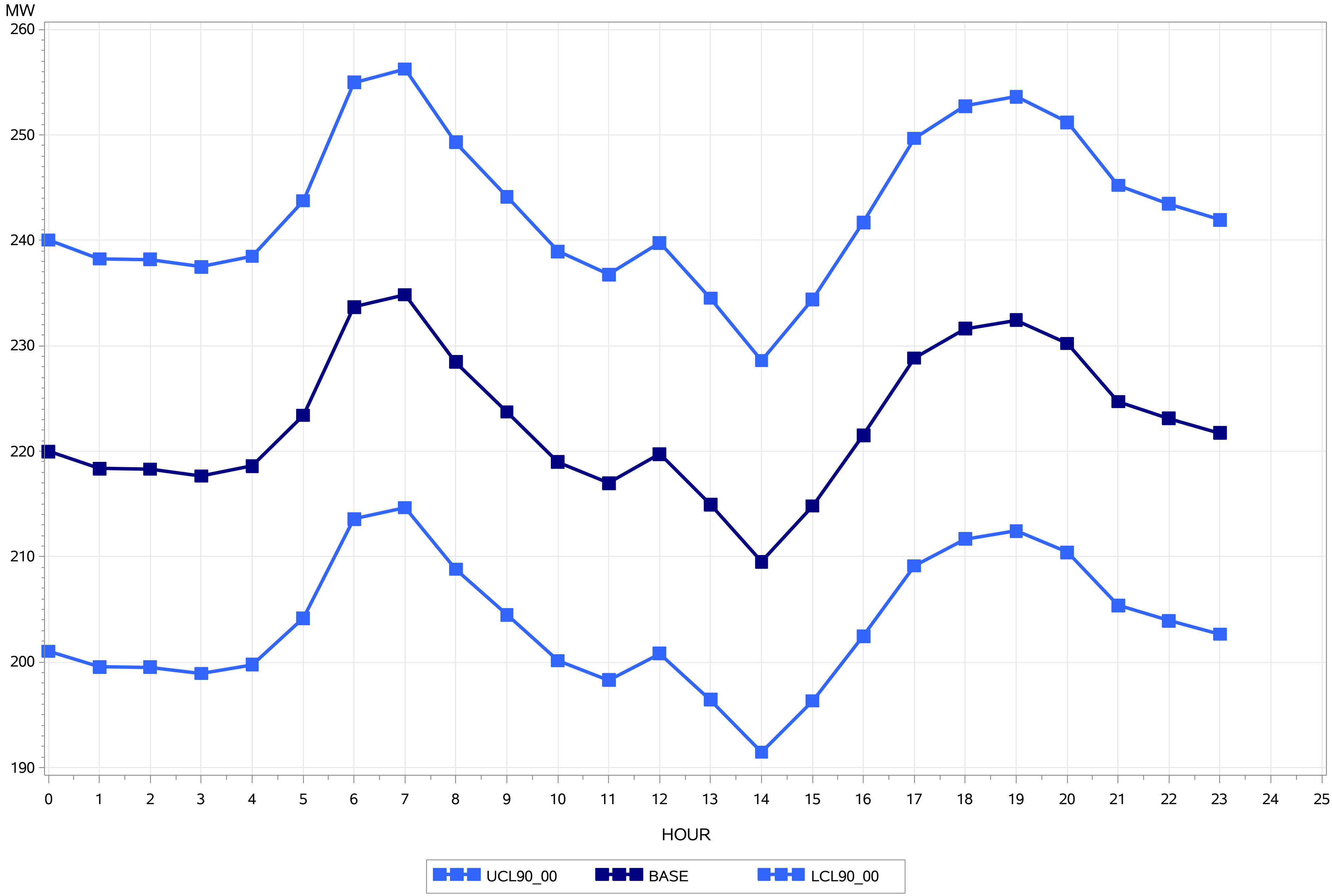
Date of On Peak Day - 12/26/2021



Member Forecasted On Peak Demand Day for January 2021

STATE OF WYOMING

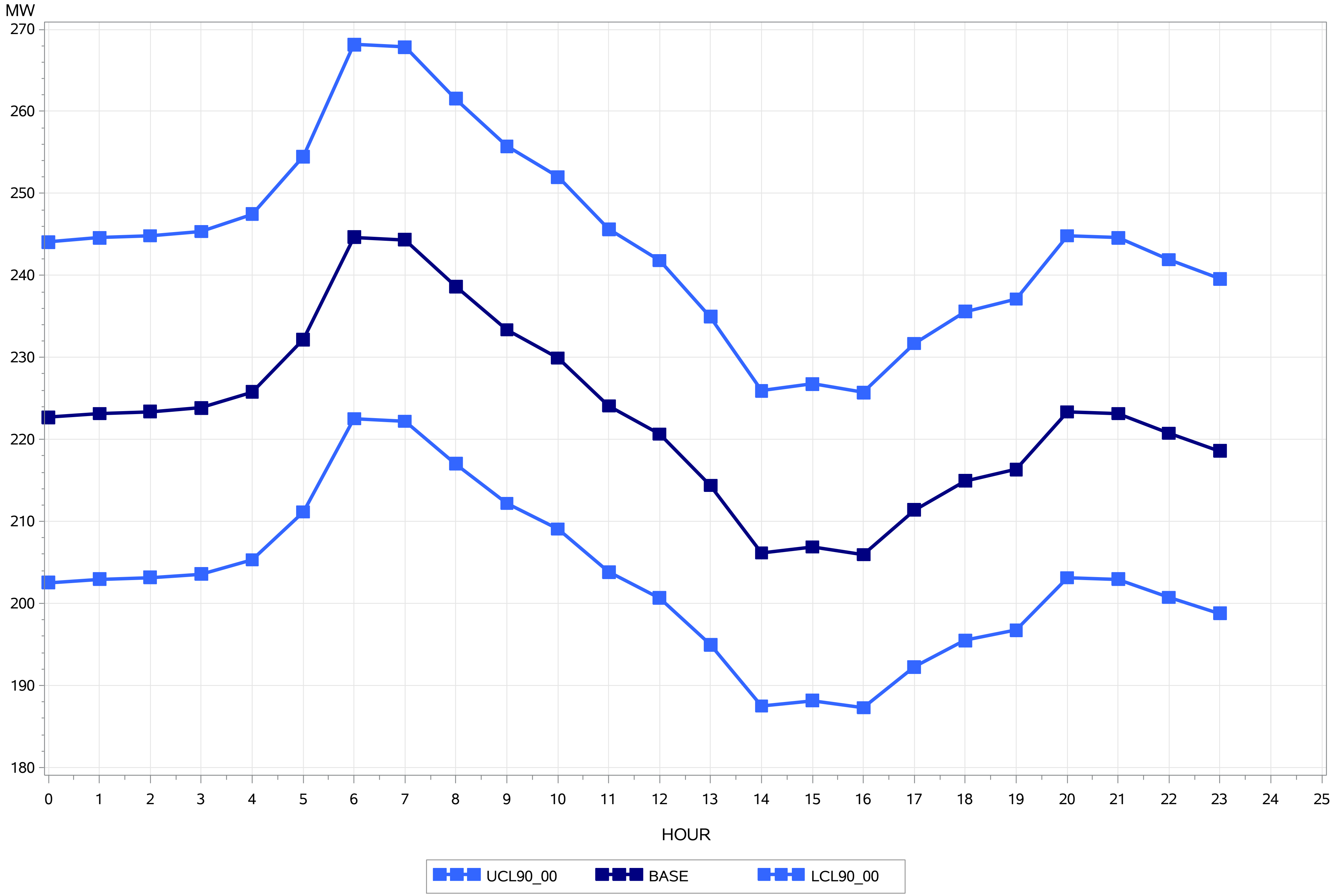
Date of On Peak Day - 01/07/2021



Member Forecasted On Peak Demand Day for February 2021

STATE OF WYOMING

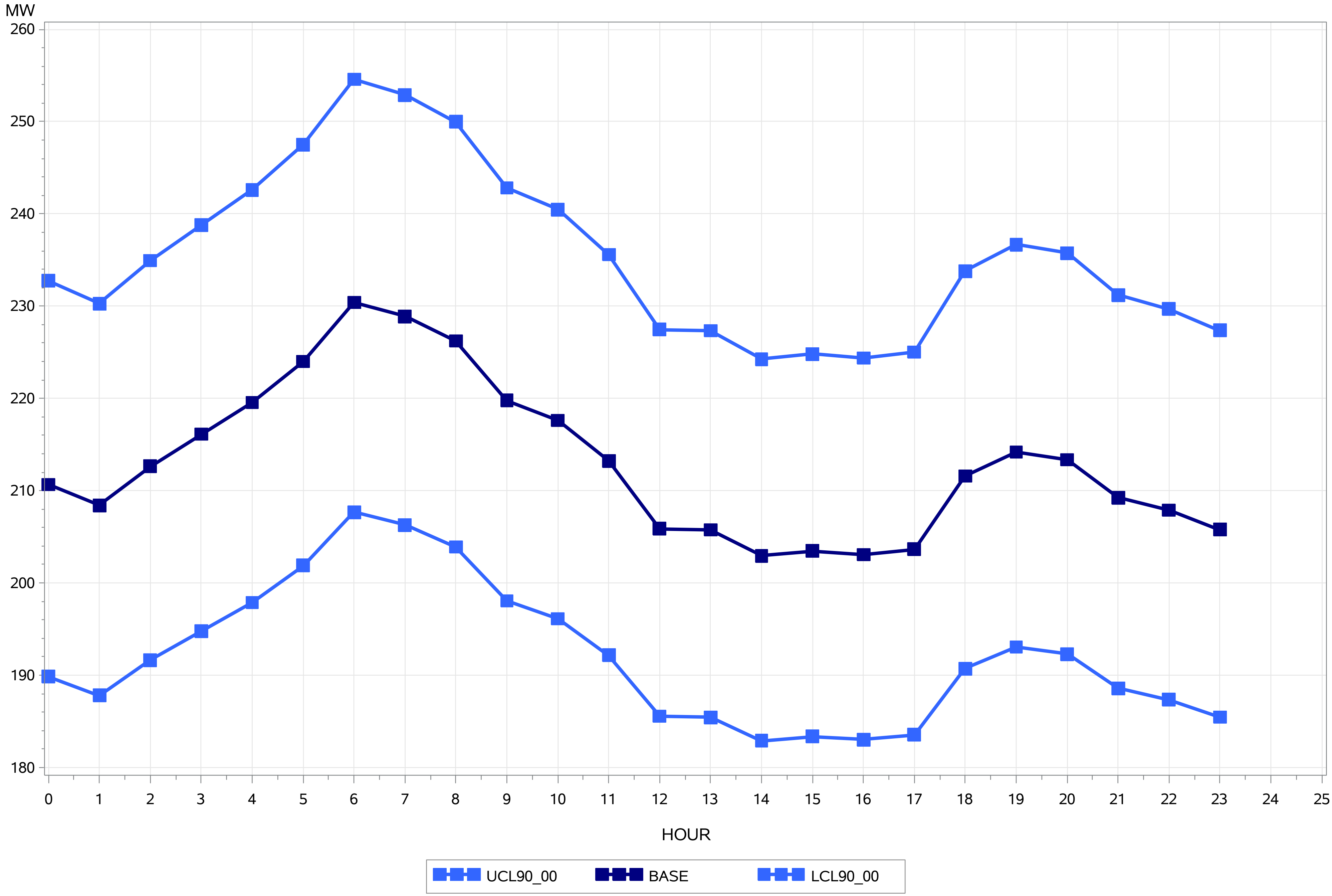
Date of On Peak Day - 02/03/2021



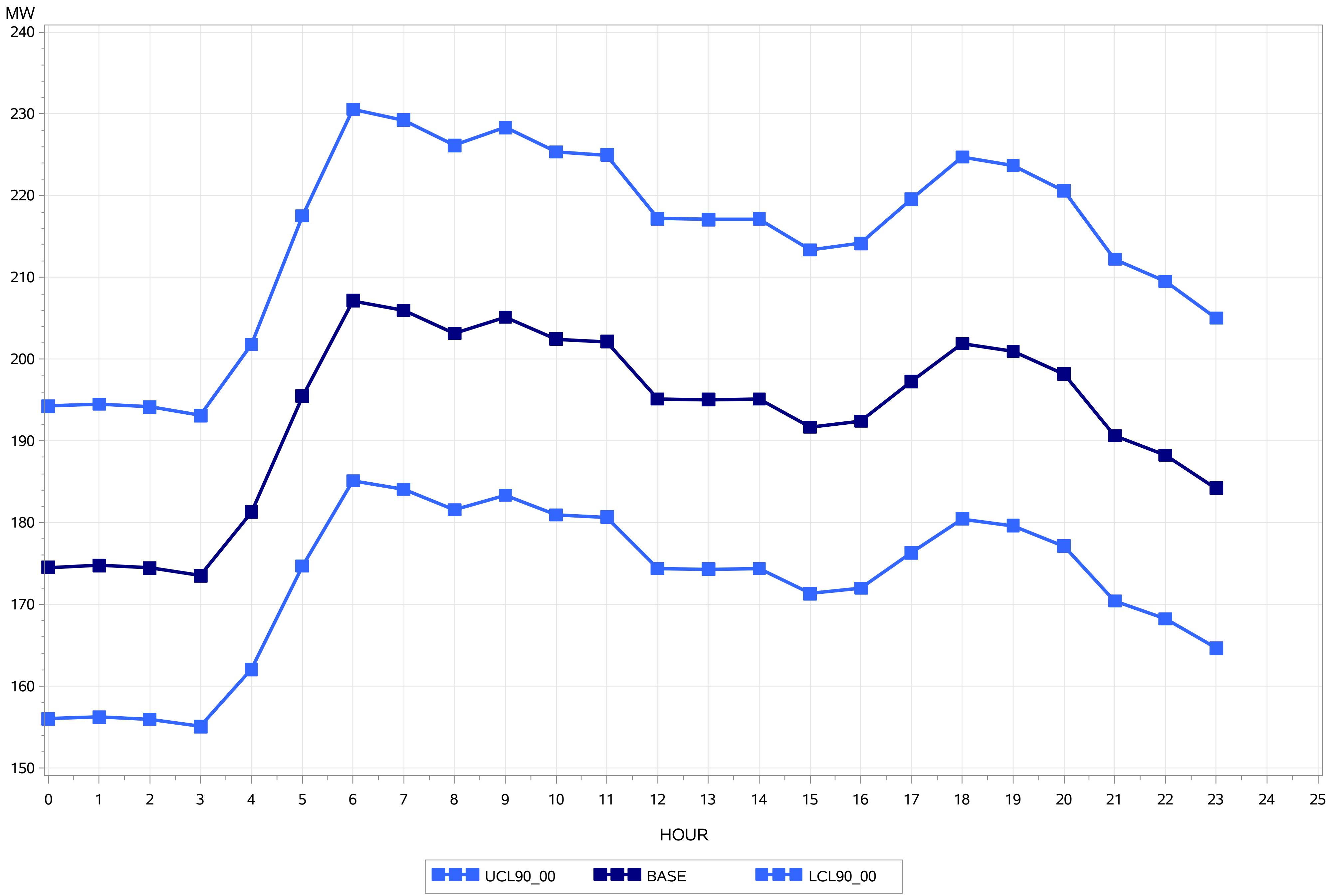
Member Forecasted On Peak Demand Day for March 2021

STATE OF WYOMING

Date of On Peak Day - 03/02/2021



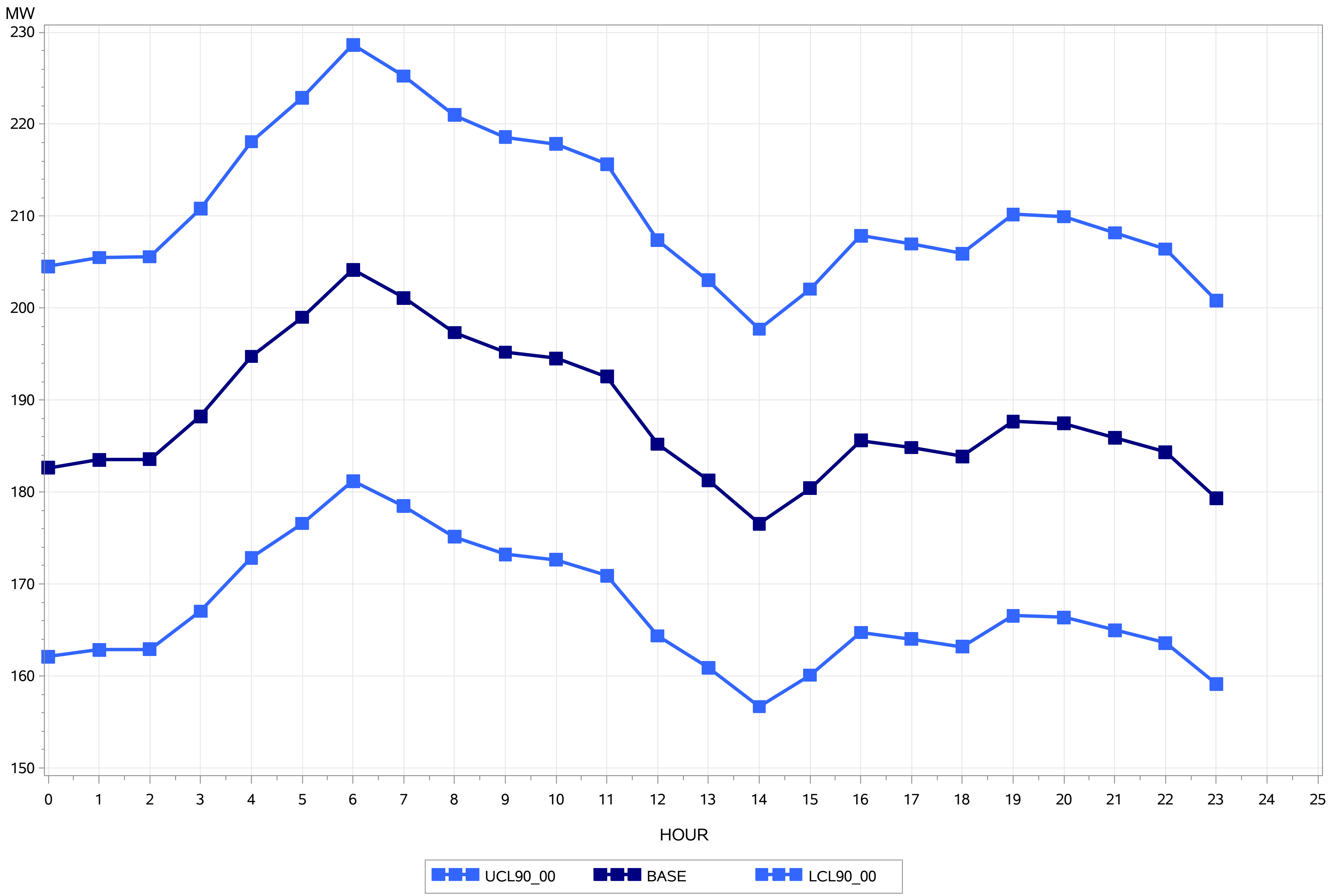
Member Forecasted On Peak Demand Day for April 2021
STATE OF WYOMING
Date of On Peak Day - 04/07/2021



Member Forecasted On Peak Demand Day for May 2021

STATE OF WYOMING

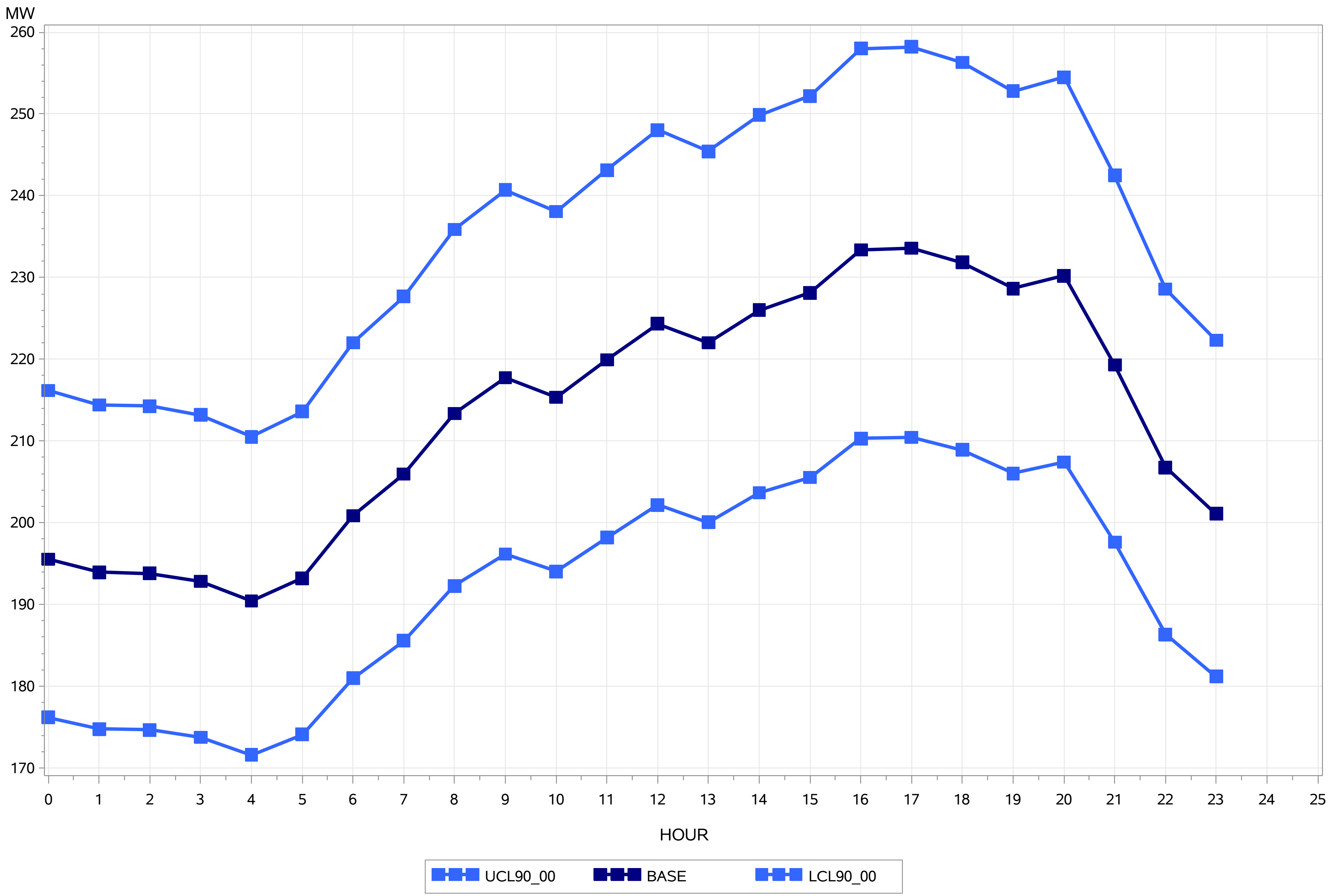
Date of On Peak Day - 05/03/2021



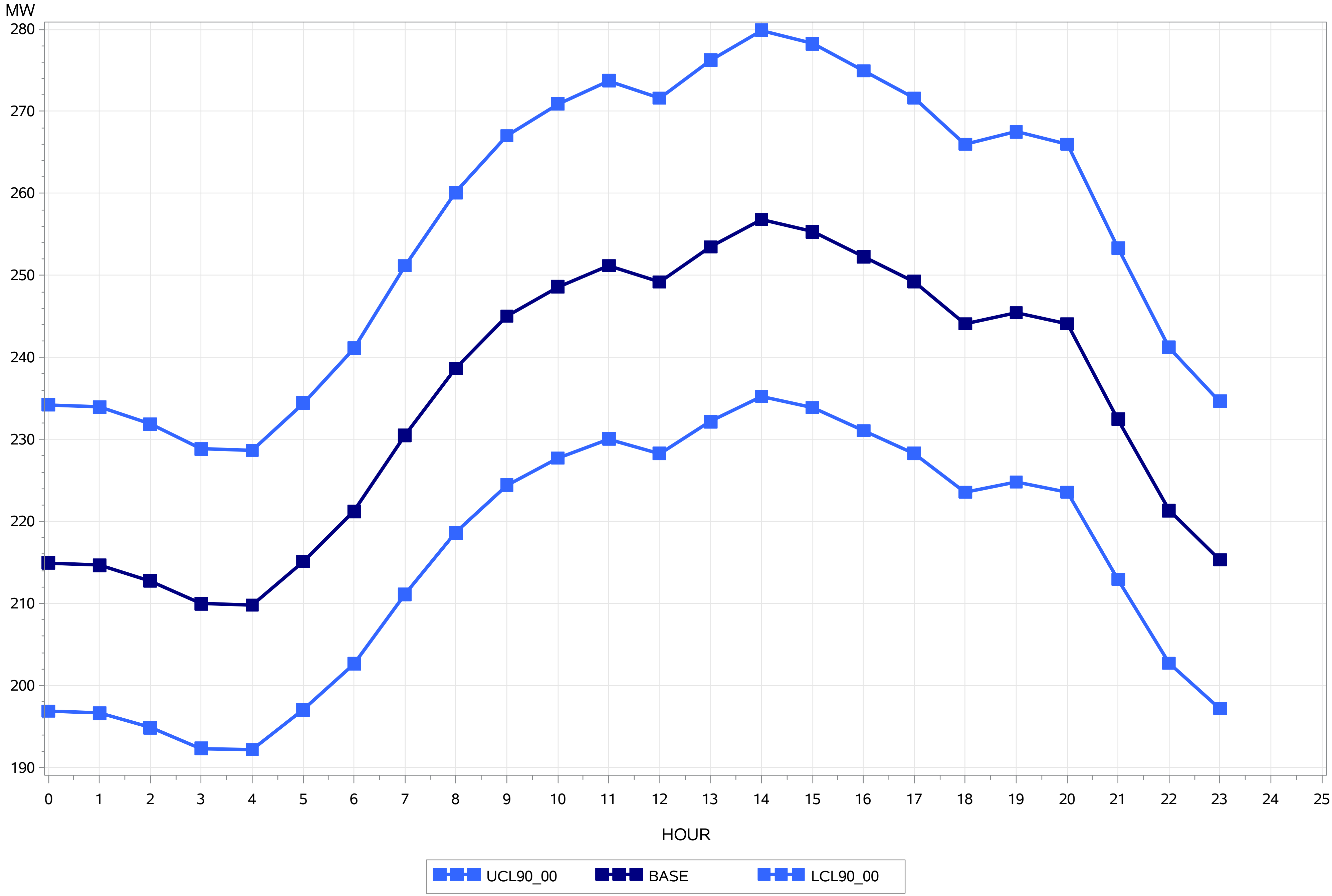
Member Forecasted On Peak Demand Day for June 2021

STATE OF WYOMING

Date of On Peak Day - 06/27/2021



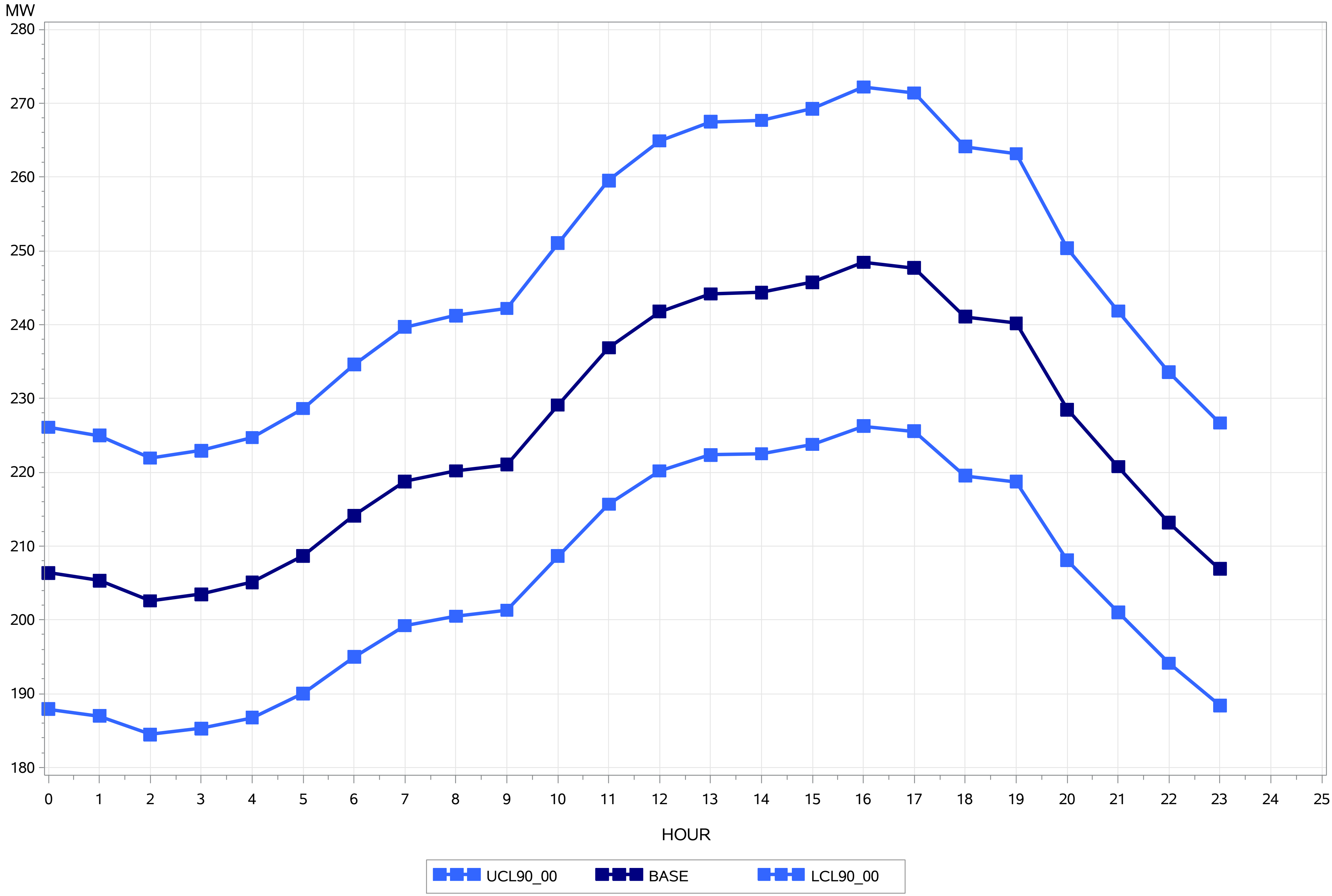
Member Forecasted On Peak Demand Day for July 2021
STATE OF WYOMING
Date of On Peak Day - 07/21/2021



Member Forecasted On Peak Demand Day for August 2021

STATE OF WYOMING

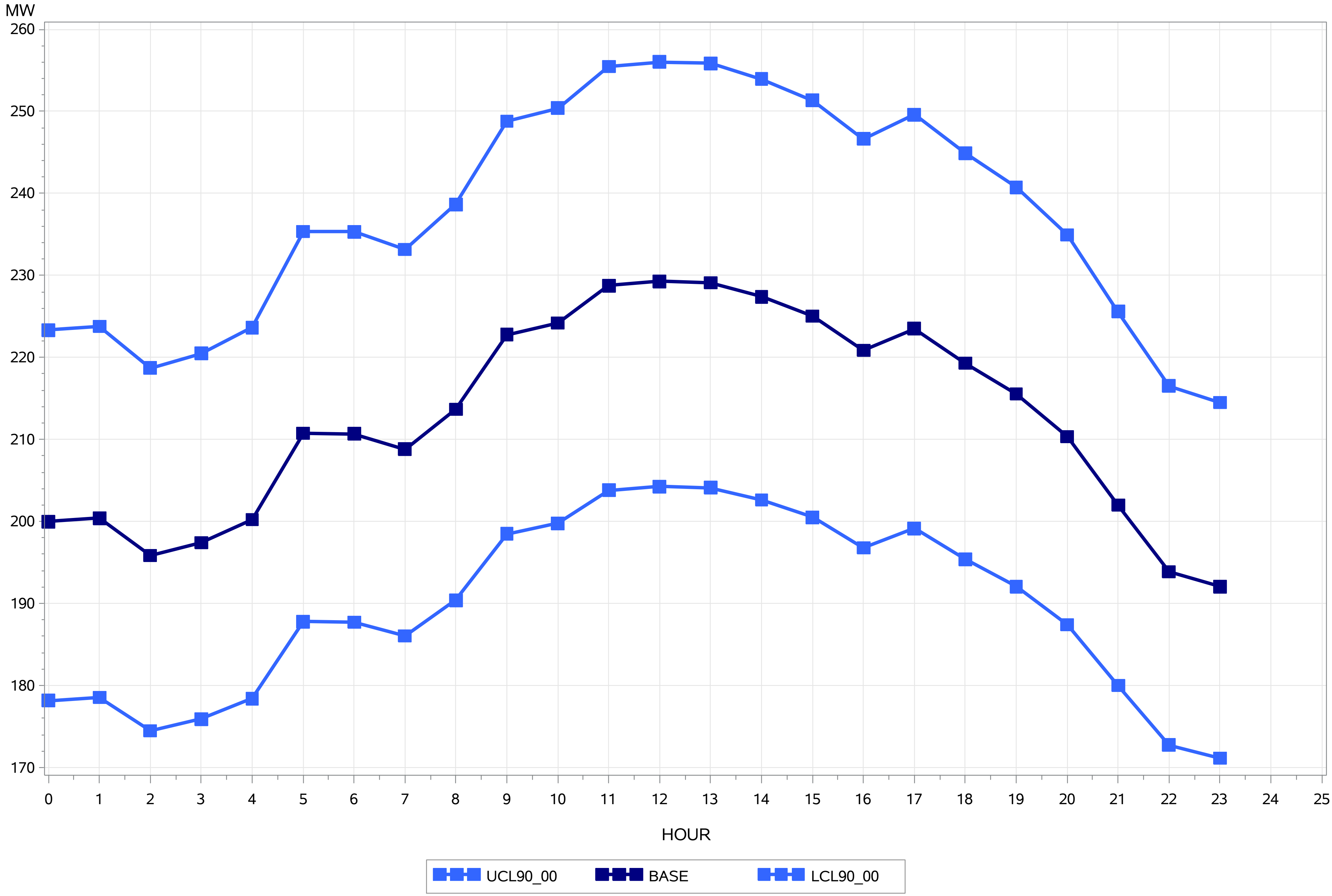
Date of On Peak Day - 08/28/2021



Member Forecasted On Peak Demand Day for September 2021

STATE OF WYOMING

Date of On Peak Day - 09/02/2021

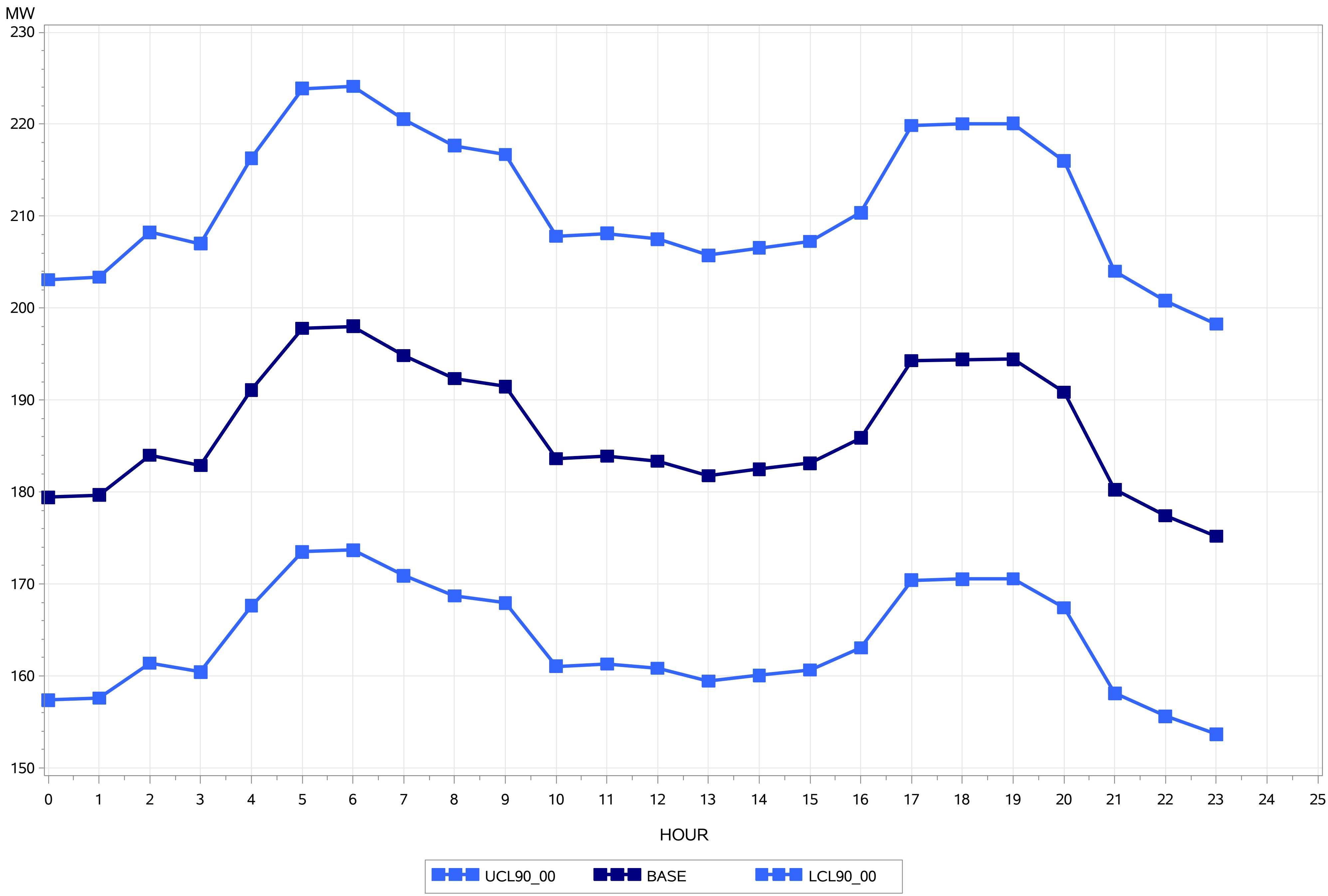


PUBLIC

Member Forecasted On Peak Demand Day for October 2021

STATE OF WYOMING

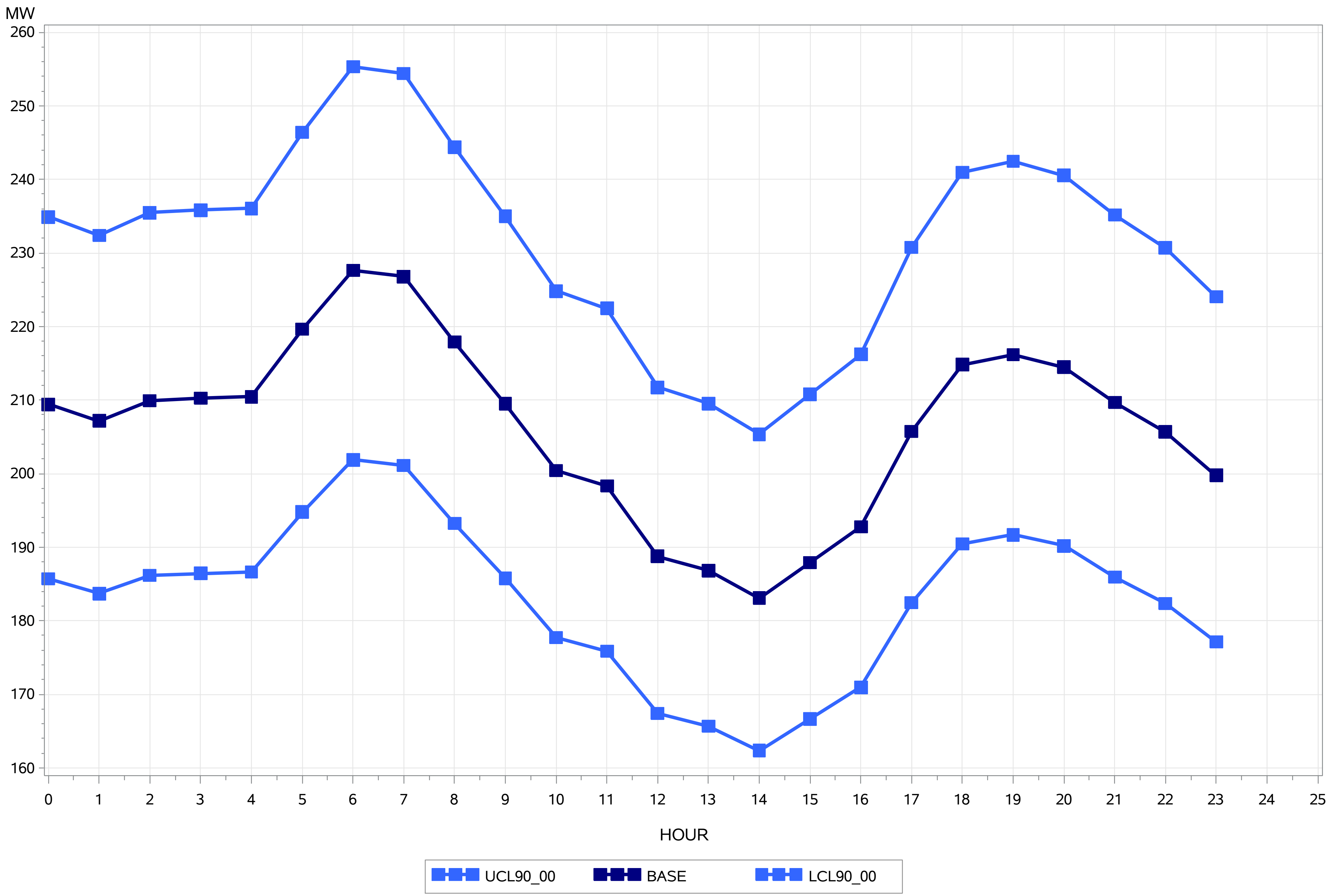
Date of On Peak Day - 10/22/2021



Member Forecasted On Peak Demand Day for November 2021

STATE OF WYOMING

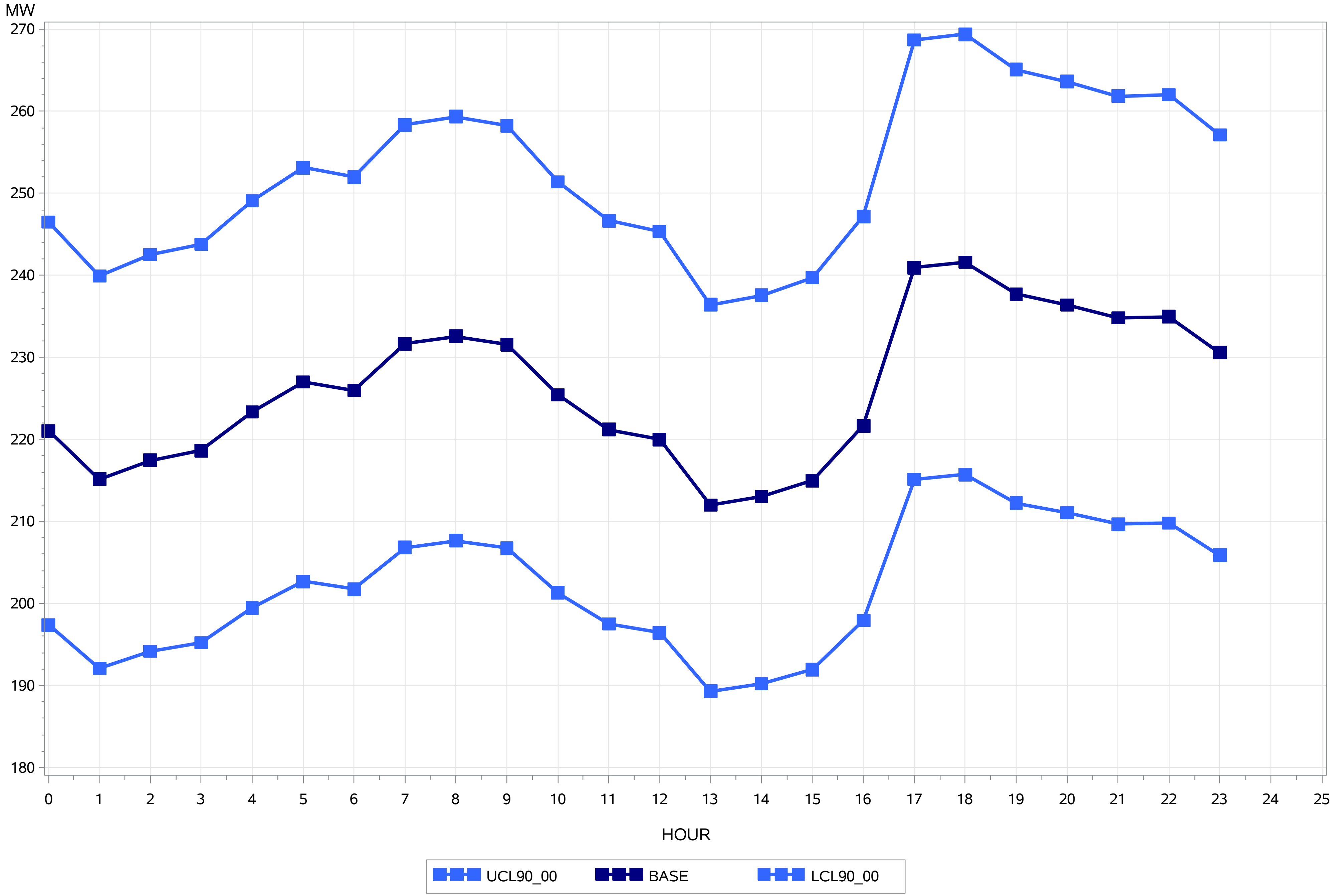
Date of On Peak Day - 11/09/2021



Member Forecasted On Peak Demand Day for December 2021

STATE OF WYOMING

Date of On Peak Day - 12/28/2021



BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-25-14

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-52:
2023 Colorado Water Plan

COLORADO WATER PLAN

COLORADO
Colorado Water Conservation Board
Department of Natural Resources

2023

CONTENTS

ACRONYMS

A.C.T.	Action Areas, Colorado Vision, Tools for Action
AFY	acre-feet per year
ARPA	American Rescue Plan Act
ASO	Airborne Snow Observatory
ASR	aquifer storage and recovery
ATM	Alternative Transfer Methods
BIL	Bipartisan Infrastructure Law
BIP	Basin Implementation Plan
BLM	U.S. Bureau of Land Management
BOR	Bureau of Reclamation
BRAT	Beaver Restoration Assessment Tool
CASM	Colorado Airborne Snow Measurement
CBT	Colorado-Big Thompson
CDA	Colorado Department of Agriculture
CDPHE	Colorado Department of Public Health and Environment
CDSS	Colorado's Decision Support Systems
cfs	cubic feet per second
CGWS	Colorado Growing Water Smart
CoRHAF	Colorado River Health Assessment Framework
COSWAP	Colorado Strategic Wildlife Action Program
CPW	Colorado Parks and Wildlife
CREP	Conservation Reserve Enhancement Program
CRO	Colorado Resiliency Office
CROS	Coordinated Reservoir Operations
CRSPA	Colorado River Storage Project Act
CSFS	Colorado State Forest Service
CSU	Colorado State University
CWA	Clean Water Act
CWCB	Colorado Water Conservation Board
CWLI	Colorado Water Loss Initiative
CWRPDA	Colorado Water Resources and Power Development Authority
CWSA	collaborative water sharing agreements
DCP	Drought Contingency Plan
DFPC	Division of Fire Prevention and Control
DHSEM	Division of Homeland Security & Emergency Management
DI	disproportionately impacted
DM	Demand Management
DNR	Department of Natural Resources

DOLA	Department of Local Affairs
DPR	direct potable reuse
DRCOG	Denver Regional Council of Governments
DROA	Drought Response Operations Agreement
DWR	Division of Water Resources
EDI	equity, diversity, and inclusion
EJ	environmental justice
EPA	Environmental Protection Agency
EQIP	Environmental Quality Incentives Program
ESA	Endangered Species Act
FACE	Future Avoided Cost Explorer
FERC	Federal Energy Regulatory Commission
FHZ	Fluvial Hazard Zone
GIS	geographic information systems
GOCO	Great Outdoors Colorado
gpcd	gallons per capita per day
HB	House Bill
HUC	Hydraulic Unit Code
IBCC	Interbasin Compact Committee
IIJA	Infrastructure Investment and Jobs Act
IPR	indirect potable reuse
ISF	Instream Flow
IWMP	integrated water management plan
LiDAR	light detection and ranging
N/A	not applicable
NEPA	National Environmental Policy Act
NGO	nongovernmental organization
NLL	natural lake level
NPS	National Park Service
NRCS	Natural Resources Conservation Service
OEDIT	Colorado Office of Economic Development and International Trade
OREC	Colorado Outdoor Recreation Industry Office
OWL	One Water Leaders
PEPO	Public Education Participation and Outreach
PRRIP	Platte River Recovery Implementation Program
RGDSS	Rio Grande Decision Support System
RICD	recreational in-channel diversion water right
SB	Senate Bill

SDO	State Demography Office
SJRIP	San Juan River Basin Recovery Implementation Program
SMP	stream management plan
SNOTEL	Snow Telemetry
STEM	science, technology, engineering, and mathematics
SUIT	Southern Ute Indian Tribe
SWE	snow water equivalent
SWSI	Statewide Water Supply Initiative
TAG	Technical Advisory Groups
TMD	transmountain diversion
TMDL	total maximum daily load
UCEFRP	Upper Colorado River Endangered Fish Recovery Program
UMUT	Ute Mountain Ute Tribe
USACE	United States Army Corps of Engineers
USDA	United States Department of Agriculture
USFS	United States Forest Service
USFWS	United States Fish and Wildlife Service
USGS	United States Geological Survey
WQCC	Water Quality Control Commission
WQCD	Water Quality Control Division
WSRF	Water Supply Reserve Fund
YWG	Yampa-White-Green Basin

COVER IMAGES AND STOCK PHOTO CREDITS

- Cover Birds take flight over the Yampa River near Steamboat Springs on the Daughenbaugh Ranch, Photo credit: M. Nager; Small Town and Suburban Sprawl In Colorado▲; Father and son fish by lake, dad looks at camera*; Aerial of green pastures and river, Photo credit: Kent Vertrees, Friends of the Yampa
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* Shutterstock Stock Image | ▲ Adobe Stock Image

CWCB BOARD LETTER

Fellow Coloradan,

Thank you for opening the Colorado Water Plan. With this document, the Board and Staff of the Colorado Water Conservation Board (CWCB) seek to respond to this historic moment in time with a plan for thoughtful and bold initiative.

Much has changed since 2015, when the first Colorado Water Plan was finalized. The impacts of widespread drought, coupled with a global pandemic, challenged our communities with far-reaching uncertainties that shaped new water management realities. The pandemic pushed our stakeholders to begin meeting virtually, bringing a new way for people to connect, learn, and get involved with the work of planning for water. These experiences also highlighted the ways in which Colorado is connected by water.

Towns and farms on the Front Range are tied to high mountain streams on the West Slope through the complicated plumbing that brings water through the Continental Divide. Beyond these physical connections, there is a shared understanding that water supports Colorado's culture, communities, recreation, forests, and foods. The fresh produce, meat, and beer enjoyed in restaurants and kitchens around our state are supplied by farming and ranching families with diverse backgrounds and often multi-generational and historical ties to the land they steward. Coloradans value healthy rivers that drive robust recreation economies and provide important corridors for fish and wildlife, quality drinking water for cities and towns, and spaces for people to connect with nature. Colorado is the state we know and love because of its lakes, rivers, streams, wetlands, and aquifers. Because water inextricably links people across Colorado, our water management challenges must be faced together.

GET INVOLVED—NOW IS THE TIME FOR ACTION

The West is experiencing growth in population and demand for water while our hydrology is becoming less predictable. Our temperatures have warmed, and the timing and amount of precipitation has changed, causing shifts in runoff and streamflows. It is clear this is not a temporary phenomenon, but rather a permanent trend toward aridification of the West. These changes, on top of existing concerns, present increased water quantity and water quality challenges especially as the rate and magnitude of ecosystem changes in Colorado have increased. These collective impacts have changed the way we think about water planning and shifted our collective approach to swift action.

The Colorado Water Plan was informed by robust stakeholder input and complex modeling that provides a data-driven understanding of our current water supply and potential future scenarios. The plan also highlights Colorado's values and follows four fundamental themes of Thriving Watersheds, Resilient Planning, Vibrant Communities, and Robust Agriculture through discussions of each of our major river basins. Most importantly, the plan sets forth ambitious yet attainable actions that will help Coloradans do more with less water, increase resiliency in the face of a changing climate, and ensure broad and diverse voices are included in future water management conversations.

The CWCB cannot do this important work alone, which is why the partner actions take into account close working relationships with sister agencies and the critical efforts of partner organizations, water users, and water managers across the state. This will require thoughtful and strategic partnerships across state agencies, Tribal Nations, local governments, water providers, and stakeholders. Colorado needs collaborative and creative solutions for balancing competing water demands for a finite resource. Whether by personal action or developing a Water Plan grant project proposal, you have a role to play.

The CWCB will also continue to lead through funding, collaboration, and the agency actions it will take. Importantly, the plan outlines a 10-year schedule for future Water Plan updates and includes the addition of an annual operations plan, which will allow the CWCB Board to consider yearly priorities and respond to shifting conditions and needs. Addressing Colorado's water challenges through partnerships and collective action ensures that competing demands for water resources decisions are balanced and maximize the benefits to current and future generations.

Colorado has always been a place where the adversity of the landscape has been tempered by its ability to inspire. While our challenges are great, our natural and human resources are too. We have a long and celebrated history of innovation in water management, and we are confident the people of Colorado will continue to rise to the occasion and take on the critical work of protecting our water supply future. The Colorado Water Plan offers a light through dark and uncertain times, bringing together wide-ranging interests and voices into a collective vision, and more importantly, a plan for action over the next ten years for both CWCB and local communities across the state.

The collective actions we take today across every corner of the state will increase water resilience for Colorado and our downstream neighbors. We hope you will consider your own role in Colorado's water future and get involved—now is the time for action.

On behalf of the staff and the current and past board members of CWCB, **thank you for reading the Colorado Water Plan.**

—The Colorado Water Conservation Board

ACKNOWLEDGMENTS

CWCB BOARD:

Chair - Jackie Brown
Vice Chair - Greg Felt
Other Directors

Steve Anderson
Jessica Brody
Paul Bruchez
Heather Disney Dugan
Heather Dutton
Dan Gibbs
Kate Greenberg
Celene Hawkins
Rebecca Mitchell
Kevin Rein
Robert Sakata
Curran Trick
Phil Weiser

Where agency directors are included in the list of CWCB Board members they are not included in their respective agencies below.

CWCB Board members (listed left to right): Robert Sakata, Paul Bruchez, Steve Anderson, Greg Felt, Dan Gibbs, Heather Dutton, Kevin Rein, Jackie Brown, Rebecca Mitchell, and Jessica Brody (not pictured: Heather Disney Dugan, Kate Greenberg, Celene Hawkins, Curran Trick, and Phil Weiser). Photo Credit: Russ Sands

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Many thanks to all other CWCB staff who helped support meetings, contracts, invoicing, outreach, and all the other work that supports the Water Plan. Special thanks to Viola Bralish, Vivian Pinellli, and Anna Porter for all event organizing and logistics support.

OTHER STATE AGENCIES

- **Colorado Department of Public Health & Environment** - Tamara Allen, Michael Beck, Ron Falco, Aimee Konowal, Jojo La, Lauren McDonell, Joel Minor, Nathan Moore, MaryAnn Nason, Jeremey Neustifter, Nicole Rowan
- **Colorado Department of Agriculture*** - Jordan Beezley, Kristen Boysen, Cindy Lair, Les Owen
- **Department of Local Affairs*** - Morgan Ferris, Elizabeth Garner, Marguerite Harden, KC McFerson, Anne Miller, Desiree Santerre
- **Colorado Outdoor Recreation Industry Office** - Conor Hall
- **Colorado Oil and Gas Conservation Commission** - John Messner
- **Division of Water Resources*** - John Hunyadi, Tracy Kosloff, Mike Sullivan
- **Colorado Parks and Wildlife*** - Karlyn Armstrong, Reid Dewalt, Rob Harris, Matt Nicholl, Ed Perkins
- **Colorado Attorney General's Office*** - Emily Halvorsen, Lain Leoniak, Jen Mele

COLORADO STATE LEGISLATIVE BRANCH

2022 Water Resources and Agriculture Review Committee - Sen. Kerry Donovan (Chair), Rep. Barbara McLachlan (Vice Chair), Sen. Jeff Bridges, Rep. Marc Catlin, Sen. Sonya Jaquez Lewis, Rep. Karen McCormick, Rep. Hugh McKean, Sen. Dylan Roberts, Sen. Cleave Simpson, Sen. Jerry Sonnenberg

COLORADO STATE EXECUTIVE BRANCH

- **Governor and Lt. Governor's Office** - Governor Jared Polis and Lt. Governor Dianne Primavera
- **Other Support Governor and Lt. Governor Support Staff** - Jonathan Asher, Kathryn Redhorse
- **Department of Natural Resources Executive Director's Office*** - Chris Arend, Angela Boag, Carly Jacobs, Tim Mauck, Vanessa Mezal, Nate Pearson, Kelly Romero-Heaney

OTHER STATE ENTITIES, GROUPS, ORGANIZATIONS, AND TASK FORCES WHO PROVIDED WATER PLAN INPUT:

Colorado Agricultural Commission, Colorado Commission of Indian Affairs, Colorado Oil and Gas Commission Colorado State Forest Service, Colorado State Land Board, Colorado Water Resources and Power Authority, Environmental Justice Action Task Force, Great Outdoors Colorado, Interbasin Compact Committee, The Basin Roundtables, The Water Equity Task Force, and the Water Quality Control Commission.

COLORADO'S FEDERALLY RECOGNIZED TRIBES

Southern Ute Indian Tribe, Ute Mountain Ute Indian Tribe

WATER PLAN CONTRACTOR CORE TEAM:

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WILSON WATER GROUP

- **Lead** - Kara Sobieski
- Brenna Mefford, Lisa Wade, and Erin Wilson

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OUTREACH & LANGUAGE TRANSLATION CONTRACT SUPPORT:

TRANSLATION SERVICES & OUTREACH

- **CREA Results** - Susana Arreola, Jack Becker, Zuza Bohley, Lida Citarella, German González, William Henao, Gabriela Pérez, Fernando Pineda, Griselda Rivera, Ana Romero, Heather Thomson
- **Community Language Cooperative**
- **Affinity Translation**

FACILITATION SERVICES

- **Strategic By Nature** - Stacy Beaugh
- **Connected Realities** - GeGe Howard; Joy Lujan

CWCB would also like to recognize all the individuals and organizations who were kind enough to support CWCB staff with more than 100 events, with at least one in each of the state's 64 counties. We are grateful for your time, for sharing booth space, for providing tours, and for your partnership.

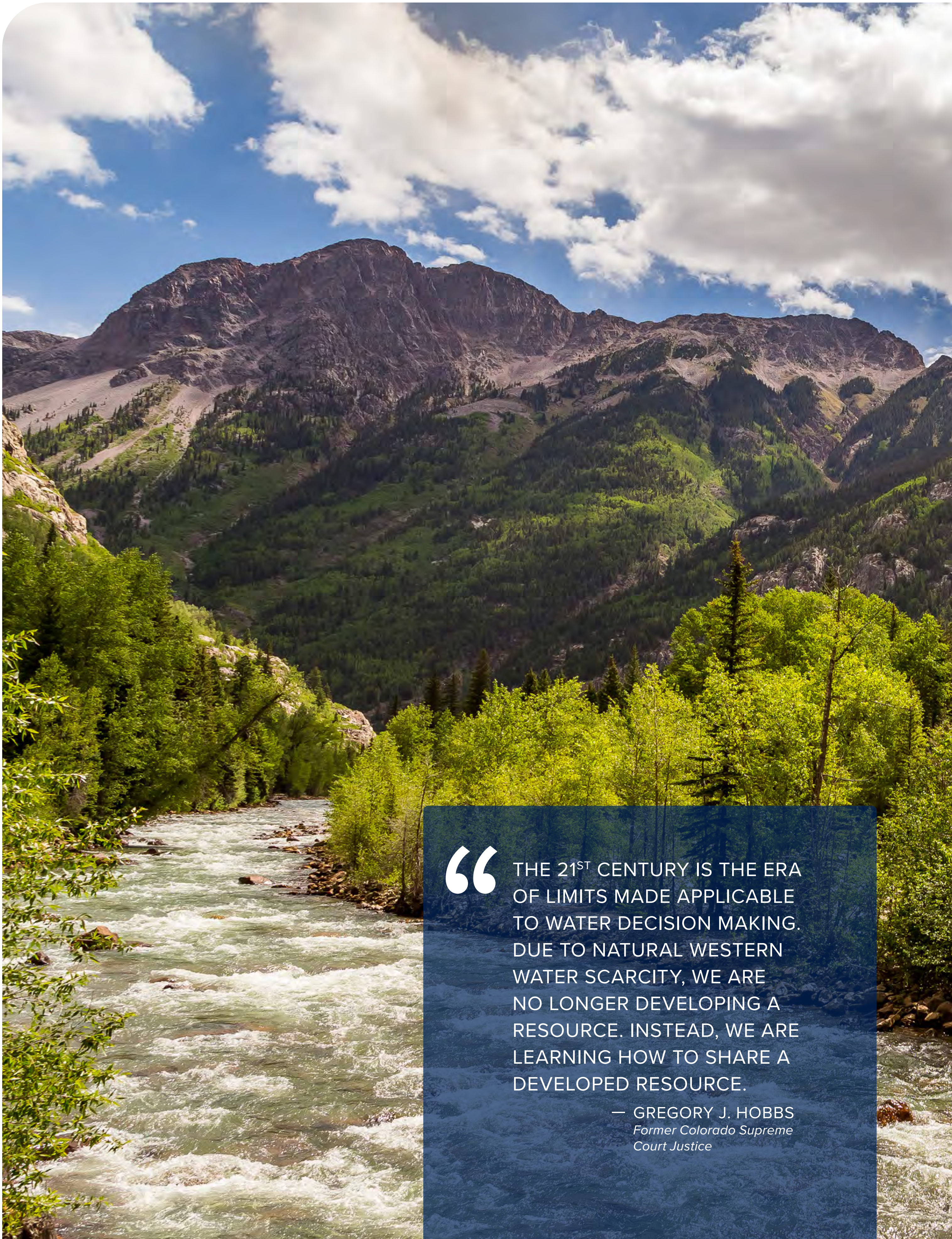
Special thanks to all those collaborating consultants who helped support the development of the Basin Implementation Plans that inform the Colorado Water Plan, including CBI, CDM Smith, Forsgren Associates, Harris Water Engineers, HDR, J-U-B Engineers, LRE Water, Rio Grande Headwaters Restoration Project, SGM, and Stantec.

Also, CWCB would like to express appreciation to those who provided input during outreach events, listening sessions, CWCB board meetings, and public comment on the Water Plan.

**Director participation noted through their role on the CWCB Board (See list above).*

CHAPTER 1

OVERVIEW



> THE 21ST CENTURY IS THE ERA OF LIMITS MADE APPLICABLE TO WATER DECISION MAKING. DUE TO NATURAL WESTERN WATER SCARCITY, WE ARE NO LONGER DEVELOPING A RESOURCE. INSTEAD, WE ARE LEARNING HOW TO SHARE A DEVELOPED RESOURCE.
>
> — GREGORY J. HOBBS
> *Former Colorado Supreme Court Justice*

Colorado's water touches every aspect of our daily lives. Those that depend on the water face unprecedented challenges that require all Coloradans to embrace a new water ethic. We must come together to protect this critical resource in increasingly innovative ways. The time for action is now.

As a headwaters state, water flows from Colorado's snow-capped peaks, through forests and streams, to cities and farms, and then returns to streams. Along the way, water supports habitat, wildlife, recreation, local food production, energy, industry, drinking water supplies, and more. Water connects us all. The importance of water in Colorado has long been recognized by the ancestral and Indigenous peoples of Colorado – the 48 Tribes that historically were the original stewards of this land include Colorado's two federally-recognized Tribes, the Southern Ute Indian Tribe (SUIT) and the Ute Mountain Ute Indian Tribe (UMUT). As noted by the Tribes, "Water is life."

Nearly 6 million Coloradans depend on the water from our major river basins as do 19 other states and Mexico, but that water supply is at risk. Population growth, long-term warming trends, major wildfires, aridification, and multi-year droughts are straining the system like never before.

We must understand these challenges, their associated risks, and the tools we can use to drive change. Tools that shape actions and policy to mitigate our risks can reshape the future. We must also be collaborative and understand the perspectives of water users from across the state. Basin Implementation Plans, developed by Colorado's nine basin roundtables, provide summaries of regional challenges, strategies to overcome them, and valuable data to inform the state's Water Plan. **The Colorado Water Plan sets the stage for a shared understanding of our risks and describes actions that collectively contribute to a stronger, more water-resilient Colorado.**

While Colorado faces enormous water challenges, its opportunities are tremendous. A secure water future will depend on our working together to uplift every area of the Water Plan. In reading this plan, it is important to know that the opportunity to take action is driven by you. Whatever your background, whatever your job, all Coloradans are a part of the solution. **Collaborative action needs to occur at every level, and the need for action has never been more urgent than now.**

BUILDING ON PAST SUCCESS

The devastation of the 2002 drought and Hayman Fire launched a new era of resiliency planning and collaboration in Colorado that led to the creation of many of the state's grassroots water stakeholder groups, the Colorado Water Plan (Water Plan), and a continued investment in water. These efforts have made real progress since the 2015 Water Plan to better manage and fund Colorado's water, as noted below:

- Water conservation measures have **decreased statewide per capita water use by 5%.**
- Colorado Water Plan grants were established and funded **almost $55 million in projects covering every corner of the state.**
- Annual municipal leasing of **25,000 acre-feet** of agricultural water has helped cities and farms coexist.[1]
- **More than 25 new** stream management plans have been developed.
- **400,000 acre-feet** of storage has either been constructed or will soon be completed.[2]
- Water outreach, education, and messaging is estimated to have **reached up to 2.7 million people.**
- Legislation was **passed to integrate land use and water planning** in comprehensive plans.
- Reclaimed water regulations have been updated with **18 additional uses** to allow water reclamation in residential and commercial crop irrigation, among others. See Chapter 5 for more information on reclaimed water regulations.
- **62% of Coloradans** now live in communities whose leaders have been trained by the Growing Water Smart program to integrate water and land use planning.
- Multi-purpose, multi-benefit projects continue to receive grant funding and **more than $420 million in loans.**
- Watershed health received millions of dollars in support as statewide **watershed groups exceed 150.**
- Colorado voters **passed Proposition DD**[3] to dedicate funding for the Colorado Water Plan Grant Program.

These successes should be celebrated because they show significant progress, firm resolve, and a blueprint for collaborative action. Yet, the need for progress is now more urgent than ever. In the last two decades Colorado's population has increased by more than a million people. Several major wildfires have ignited our forests and grasslands, and drought, along with a larger trend in long-term warming and drying, known as aridification, continues to challenge water resources. Significant swaths of agricultural lands have been lost to buy and dry practices, water supply reductions, and urbanization; forests face continued risk from fire; and streams face new challenges for habitat protection.

Colorado's nine basin roundtables have been instrumental in fostering our past successes and forming the future vision described in the Water Plan. Chapter 4 describes local challenges, recent achievements, and strategies to meet future needs that each basin roundtable provided in their Basin Implementation Plans - all of which inform the Water Plan.

In the face of this adversity, there has been a groundswell of collaborative action leading to real progress through holistic and multi-benefit projects. **It is increasingly important to make sure every water project or strategy uses water as wisely as possible, making it stretch as far as it can to realize its maximum value for cities, farms, streams, and people.** Doing so will require shared stewardship—a commitment to partnership in which the state government and every Coloradan must work together toward greater action.

[1] Generalized findings from Alternative Transfer Methods in Colorado, Status Update, Framework for Continued Support, and Recommendations for CWCB Action

[2] Includes Chimney Hollow Reservoir (90,000 acre-feet), Glade Reservoir (170,000 acre-feet), Galeton Reservoir (45,600 acre-feet), Gross Reservoir Expansion (77,000 acre-feet), and Chatfield Reallocation (20,600 acre-feet)

[3] Proposition DD is a legislatively referred state statute on the November 2019 ballot that was ultimately codified in HB19-137 and provided funds from sports betting to be used, among other things, to fund the Water Plan through the creation of a Water Plan Implementation Cash Fund that is used to support CWCB's Colorado Water Plan Grant Program.

EMPOWERING STAKEHOLDERS

As the stewards of the Water Plan and the agency charged to conserve, develop, protect, and manage Colorado's water for present and future generations, CWCB works with partners to foster action by funding local water projects through grants and loans. The CWCB also works on multiple programmatic efforts related to interstate compacts, flood mitigation, species protection, water project financing, agricultural support, and climate adaptation, all of which advance the goals of the Water Plan.

The CWCB does not build projects. It advances projects, often focusing on proven methods, by supporting project proponents with funding, analysis tools, technical assistance, programs, and policies that can help advance toward a future envisioned by the values and ideas in this Water Plan. The real power of the Water Plan is often driven by local and regional innovation, action, and project development that advance when stakeholders take action. This is readily apparent in the work that the state's nine legislatively-created basin roundtables completed to identify more than 1,800 local projects and plans in the lead-up to the Water Plan update (See Chapter 4).

Meeting the moment extends well beyond what one agency or the entirety of the state government can do. The power of nearly 6 million Coloradans rallying to embrace a new water ethic in Colorado is what we need to be successful. The Water Plan is a call to action backed by governmental support that can catalyze local planning and projects.

The Water Plan was informed by and built through stakeholder input. Basin-specific technical analyses, local stakeholder input, and statewide outreach informed the Water Plan by explaining local conditions, offering examples of successful projects, and gathering information about future projects needed for increased water resilience. The process involved ongoing work with basin roundtables and the Interbasin Compact Committee (IBCC), engagement with more than 1,200 stakeholders providing feedback during Water Plan scoping, multiple partners (agencies, Tribes, nongovernmental organizations [NGO], and members of the public) as well as a governor-created Water Equity Task Force. Stakeholders were also engaged during public review of the draft Water Plan through outreach events in all 64 Colorado counties, more than 2,000 submitted public observations on the draft plan, and more than 500 pages of public comment letters. Approximately 130 public comments were submitted in Spanish. This spirit of collaboration and the focus on Colorado water resilience is at the heart of the Water Plan, and implementing the Water Plan is critical to Colorado's future.

PUBLIC ENGAGEMENT AND WATER EQUITY TASK FORCE

Building on years of ongoing grassroots input, CWCB included a scoping phase early in the Water Plan update process to evaluate the critical issues on stakeholders' minds and provide a platform to discuss CWCB's proposed direction for the Water Plan. As part of that effort, CWCB partnered with 20 agencies and NGOs to hold more than a dozen sector-specific workshops that engaged more than 1,200 stakeholders. Targeted interviews, online surveys, and an online stakeholder engagement platform supplemented the scoping outreach. This work gathered extensive input on stakeholder issues related to agricultural, municipal, watershed, and forest health needs. Themes that sparked a wide range of interest for incorporation in this Water Plan included addressing climate change and drought as well as the need to better recognize equity, diversity, and inclusion (EDI) in water issues.

Realizing that more time was needed to discuss EDI concerns and to bring in multiple perspectives, CWCB worked with the Department of Natural Resources (DNR) and the Governor's Office to create a year-long Water Equity Task Force that focused on developing a set of principles to help inform the update to the Water Plan. The 21-member task force included nine basin roundtable members (one from each roundtable), nine community members (one from each of the eight major river basins and the Denver metropolitan area), two members from each of Colorado's federally recognized Tribes, and one member from the Acequia community.

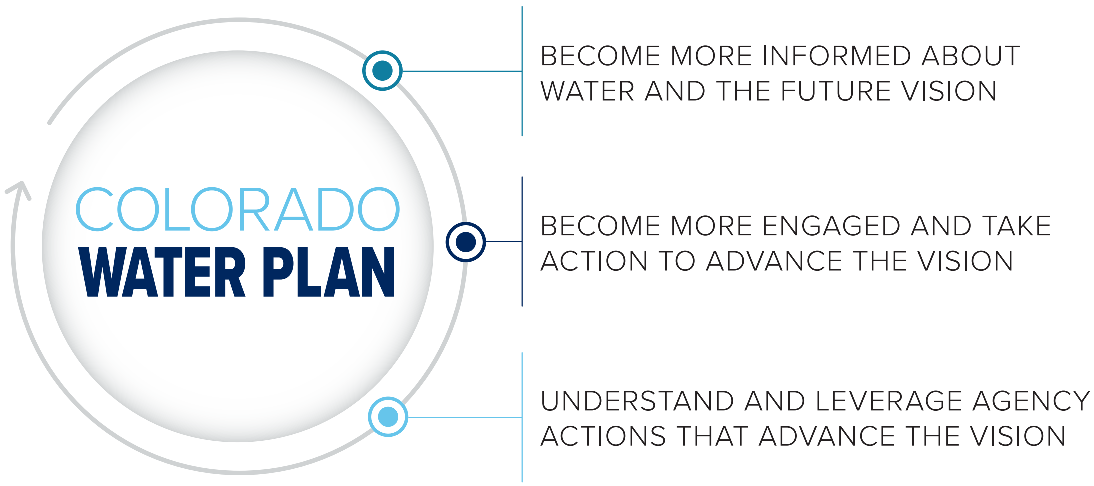
The Water Equity Task Force's guiding principles include a need to:

1. **Promote diversity** in career pathways in water-related fields through education and engagement.
2. **Promote collaboration**, new voices, and greater community engagement in water discussions.
3. **Recognize and address elements of the rural-urban divide** but focus on creating the rural-urban opportunity.
4. **Expand grant opportunities** to new audiences.
5. Support basin roundtables facilitating broad **community engagement and collaborative solutions.**

In addition to directly informing the Water Plan's development, CWCB uses these guiding principles to inform programming, policies, and engagement for the benefit of all Coloradans.

USING THE PLAN

The Water Plan can be used in three primary ways:



Use the plan to **become more informed about water and the future vision.**

The State of Colorado encourages its residents to be informed about water issues, but a 2021 Statewide Water Awareness Survey indicated that only 35% of Coloradans are confident they have the knowledge necessary to take action to manage our water use. Becoming more informed about water and the future vision is a critical first step. It creates ripple effects in what we value, how we invest, and how we conserve. It is also foundational to collaborative and inclusive water planning. For many, understanding the complex water challenges Colorado faces, the tools that can be used to find solutions, and Colorado's shared vision will be an important commitment.

Opportunities to participate at this level include:

- Support local water initiatives and projects
- Conserve water indoors and outdoors
- Practice wise stewardship of our rivers, lands, and natural resources
- Purchase water-saving products and locally grown food products
- Help promote water conservation and water outreach efforts
- Support local utility/city/county water conservation, local food, and resilience

Use the plan as a platform to **become more engaged and take action to advance the vision.**

The Water Plan is a starting point, and it provides a larger framework for next-level action. If you can do more, whether because you are a water rights holder, a county commissioner, a water utility worker, a city planner, a business owner, a local leader, or a concerned resident looking to become more engaged, this is your time. The Water Plan provides your roadmap to identify and collaborate in implementing solutions to Colorado's water resources challenges.

Opportunities to participate at this level include:

- Attend a local water meeting (e.g., **basin roundtable**)
- Join a water-focused stakeholder group (e.g., NGO or basin roundtable)
- Start a local food or watershed group
- Apply for a grant to take action on the Water Plan
- Invest in water-efficient equipment in your home, business, or farm
- Work with your local community leaders to advance water projects

Use the plan to **understand and leverage agency actions that advance the vision.**

For the State, the Water Plan serves as a call to action, shared leadership, and partnership. Elected officials throughout the state use the Water Plan to understand policy priorities. The executive, judicial, and legislative branches all have important roles in water discussions. Yet not one of these branches of government, nor the 180 or more state agencies, can create the necessary solutions alone. The State's role in the Water Plan is to use its collective resources to set a vision that is backed by funding and support tools to advance solutions.

Opportunities to participate at this level include:

- Attend a state water meeting (e.g., CWCB board meeting, basin roundtable meeting, legislative hearing, or committee meeting)
- Apply to join a water-focused board or commission
- Learn about and use State tools that have been developed to support action
- Engage with the State to create new supporting tools and processes
- Implement a local project that aligns with the Water Plan and, if possible, use state and federal resources to help fund the project
- Coordinate with local leaders to advance water policy

"EVERYONE NEEDS TO UNDERSTAND HOW VALUABLE WATER IS, NOT JUST TO NATIVE PEOPLE, BUT TO EVERY SINGLE ONE OF US… IT'S ALL OF US WORKING TOGETHER TO UNDERSTAND THAT WATER TRULY IS THE ESSENCE OF LIFE.

— LORELEI CLOUD
from the Water Equity Task Force Public Workshop

PLAN ORGANIZATION

The Water Plan is structured to create a line of sight from Colorado's water values to the specific actions that address challenges. The four values in the Water Plan are based on extensive work with stakeholders and include:

- A productive economy that supports vibrant, sustainable cities, agriculture, recreation, and tourism
- An efficient and effective water infrastructure system
- A strong environment with healthy watersheds, rivers, streams, and wildlife
- An informed public with creative, forward-thinking solutions that are sustainable and resilient to changing conditions and result in strong, equitable communities that can adapt and thrive in the face of adversity

Most simply, these values represent the Colorado way of life—they are the things that make Colorado great. They are also the values that help inform the Water Plan organization and drive us to act. Taken as an acronym, our values drive us to A.C.T. through **A**ction Areas, **C**olorado Vision, and **T**ools for Action.

Action Areas

The Water Plan is organized around four overarching action areas that loosely translate to cities, farms, streams, and people. The action areas are interrelated in that issues related to steams, river recreation, commerce, agriculture, diversity, and climate challenges often are interwoven and connected. The action areas are presented separately for organizational purposes, but the Water Plan also describes how they integrate. The action areas include:

VIBRANT COMMUNITIES: counties, municipalities, utilities, cities, towns, businesses, large industries, large and small urban and rural communities, etc.

ROBUST AGRICULTURE: established crops and farms, local food, orchards, ranching, ditch companies, acequias, urban agriculture, livestock, dairy, etc.

THRIVING WATERSHEDS: environment and recreation, river health, watershed health, forest health, wildfire mitigation, wildlife and aquatic species protection, etc.

RESILIENT PLANNING: climate adaptation, planning for climate extremes, embracing EDI (equity, diversity, inclusivity), education, outreach and engagement, supportive government, etc.

Sunset over Yampa River, Photo credit: Kent Vertrees, Friends of the Yampa

Colorado Vision

The Colorado Vision, outlined in Chapter 6, describes how Colorado can achieve greater resilience across and within the four action areas as we look to the planning horizon of 2050. The vision for each action area first describes our desired future and then provides examples of the kinds of local actions stakeholders and partners can take to help realize the vision. Example actions are grouped into categories, including thoughtful storage, meeting future water needs, wise water use, healthy lands, and engaged partners. In addition, each action area vision describes ways in which it intersects and integrates with other action areas to demonstrate how the areas are intertwined and relate. The overarching vision for each action area is described below.

VIBRANT COMMUNITIES

Holistic water management is essential for creating vibrant communities that balance water supply and demand needs to create a sustainable urban landscape. Colorado communities need resilient water supplies, water-conscious and attractive urban landscapes, planning that integrates land use and water solutions, and residents who understand the importance of water to their lives and economy. An integrated One Water ethic is necessary to create the transformative change needed to meet the moment and the future.[4]

ROBUST AGRICULTURE

Agriculture not only provides food and fiber, but it is also important to Colorado's culture, heritage, and economy, and it faces unprecedented challenges. Innovations are needed to sustain irrigated agriculture, including strategies to stretch available water supplies, increase resiliency, enhance food production, and maintain profitability. Water supplies for Colorado's urban growth should not come at the expense of our rural communities through indiscriminate buy and dry methods. Collaborative partnerships among agriculture, environmental groups, and municipal water providers should be used to create multi-purpose projects that help keep irrigated lands in production and maintain ecosystem services.

THRIVING WATERSHEDS

Colorado's watersheds hold the future of our water supply security. Comprehensive water resources planning should incorporate conditions of forests, streams, wetlands, and wildlife habitat. As our state's water source, the health of watersheds affects agriculture, downstream communities, recreation, tourism, and ecosystem function. Colorado will continue to follow a shared stewardship ethic to plan and implement multi-benefit projects to enhance the health of our watersheds.

RESILIENT PLANNING

Water security is critical to the quality of life, environment, and economy of Colorado. The future is uncertain, and Colorado needs to be adaptive and resilient to face the challenges ahead. Water security roadmaps, inclusively developed at a local level and informed by strong state leadership, can identify acute and chronic risks to water supply, integrate local planning strategies, prioritize collaborative solutions, and build adaptive capacity and resilience.

[4] "One Water" means matching the right water to the right use. See glossary and Chapter 6 for details and graphic.

Tools for Action

Tools for action are the means through which partners and agencies can address water issues and meet water needs. They include:

- Public outreach and education
- Funding
- Policy and regulatory changes
- Collaboration groups
- Watershed planning
- Climate adaptation
- Innovation
- Equity
- Endangered and threatened species recovery programs
- Natural hazard planning
- Land use and water planning integration
- Data collection and sharing
- Water storage
- Conveyance infrastructure
- Water efficiency and conservation programs
- Water reuse
- Collaborative water sharing agreements
- Stream/watershed restoration and enhancement
- Flow enhancement and maintenance

Actions include:

50 PARTNER ACTIONS

While the list of partner actions is limitless, the Water Plan describes approximately 50 ideas for potential actions that could be supported by Water Plan grants.

THESE INCLUDE ACTIONS AROUND

- Increased personal conservation
- Starting a new water initiative/project
- Developing collaborative solutions

50 AGENCY ACTIONS

The Water Plan includes 50 actions CWCB and supporting agencies will take to help advance local initiatives that support the wise development and conservation of water resources.

THESE INCLUDE ACTIONS AROUND

- Developing frameworks and convening groups
- Advancing research and science
- Creating support tools

Tracking Progress

This Water Plan replaces the previous plan with transparent and trackable actions. Partner actions will be tracked through CWCB's increasingly modernized process for tracking of grants and loans as well as projects through the Project Database. As CWCB tracks the completion of the agency actions it leads, CWCB will also document major legislative and basin advancements that occur—especially where the State has played a role.

Specific actions that inform the CWCB Board's annual operating plans and processes like the next Technical Update offer opportunities to identify trends, analyze progress, and explore new data and information that will help CWCB stay nimble and responsive to shifting conditions. Implementing the plan embraces the spirit of resilience—being adaptive to both acute and chronic challenges. The Water Plan is meant to be broad and flexible enough to do all of this, but it needs you to help carry out the larger vision for water management in Colorado that uplifts all areas and people in the state.

The Path Forward

The Water Plan is a call to action. Answering the call is a commitment to long-term water collaboration, resolve in the face of adversity, and developing creative solutions that allow Colorado to advance within the bounds of our legal framework. Coloradans must come together across diverse groups and geographies to envision and implement actions that will move us closer to a resilient water future. This is how we keep Colorado strong.

We are all interconnected from our headwaters to our homes by water and have a shared responsibility to it. However you interact with water—through your drinking water tap, buying food at your farmers market, enjoying the first snowfall, or recreating in one of Colorado's watersheds—you are a steward of the Water Plan. Embrace it.

"OUTDOOR RECREATION IS NOT ONLY A KEY PILLAR OF COLORADO'S ECONOMY BUT ALSO A MAJOR CONTRIBUTOR TO OUR QUALITY OF LIFE, MENTAL HEALTH AND PHYSICAL HEALTH.

— CONOR HALL
Colorado Outdoor Recreation Industry Office Director

Water Plan Layout

Following this introduction, the Water Plan describes the critical elements of Colorado's history, geography, legal setting, and water-planning efforts. The background and context provide key pieces of information that guide the direction of the Water Plan.

- Water Plan methods for analyzing future water conditions (Chapter 2)
- Geography, variability, and use of water in our state and legal underpinnings for managing it (Chapter 3)
- Basin context and summary information, including potential costs of projects to meet future water needs (Chapter 4)
- Tools that can be used to take action (Chapter 5)
- Statewide vision for a more water-resilient Colorado, along with partner and agency actions (Chapter 6)
- Process for tracking and updating the Water Plan (Chapter 7)

Accessing the Plan

The Water Plan allows the reader to engage at the levels that work best for them.

1. **Executive Summary** - High-level description and highlights of the Water Plan.
2. **Water Plan** (full document) - Foundational background information, future vision, and actions.
3. **CWCB Website** - Current CWCB efforts and background materials (cwcb.colorado.gov)

You can also find additional links and interactive resources at cwcb.colorado.gov

This updated Water Plan replaces the original Water Plan developed in 2015.

Potato Harvest
Photo credit: Sinjin Eberle

CHAPTER 2

TECHNICAL ANALYSIS, SCENARIOS, and DRIVERS

TECHNICAL ANALYSIS OVERVIEW

Following the launch of the Water Plan and the Basin Implementation Plans (BIP) in 2015, CWCB initiated the process of updating the underlying water supply and demand analyses, which culminated in the Analysis and Technical Update to the Colorado Water Plan (Technical Update), completed in 2019. The work began with the input of Technical Advisory Groups (TAG) that included representatives from across the state who provided expertise and advice on assumptions and methods for the Technical Update analyses. The resulting Technical Update (formerly known as the Statewide Water Supply Initiative or SWSI) established a new approach to statewide water analysis and data sharing.

The Technical Update leverages a significant investment of over three decades in statewide water modeling efforts, which began in 1992. To that end, the Technical Update provides a significant improvement in the scope, science, and approach to water supply planning. The approach positions Colorado for a streamlined and robust evaluation of its future water needs.

The 2015 Water Plan set an adaptive management framework for future water planning activities and described five plausible futures (or planning scenarios) under which demands, supplies, and gaps (difference between demand and supply) were to be estimated. The scenarios included new considerations, such as climate change, that were not a part of analyses prior to the 2019 Technical Update. In addition, CWCB has continued to work with the Division of Water Resources (DWR) to develop and refine consumptive use and surface water allocation models that were not ready for use in earlier analyses. The Technical Update data sets were developed to be readily updatable, and during the recent BIP update process some data sets were further refined with basin roundtable input. As a result of these factors, the Technical Update took a leap forward with a different and more robust approach to estimating future gaps.

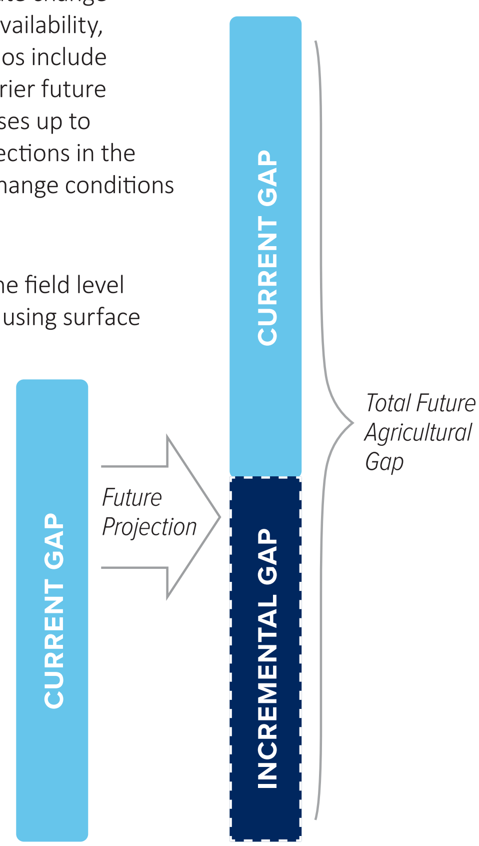
Click this link for more information on the Analysis and Technical Update to the Water Plan: **Analysis and Technical Update**

Section 2 of the Technical Update (Volume 1) summarizes the methodologies used to estimate current and future municipal/industrial and agricultural demands, water supplies and potential gaps, and tools for evaluating environment and recreation needs. Volume 2 of the Technical Update includes technical memoranda with detailed descriptions of methodologies and analysis results. The methodologies used for the Technical Update build on previous datasets as well as new and improved data sources. To the extent possible, the Technical Update leveraged Colorado's investment in models and datasets developed through Colorado's Decision Support System (CDSS). Highlights of the new methodologies are described below.

- **Incorporation of scenario planning:** The 2015 Water Plan introduced scenario planning and included five scenarios that describe Colorado's potential water situation in the year 2050. The Technical Update conducted analyses of future demands, supplies, and additional water needs in the context of the potential future scenarios.
- **Municipal water use efficiency reporting data:** New data describing recent municipal water usage was employed to estimate municipal water demands. The data are collected and reported by water providers pursuant to House Bill (HB) 10-1051 (1051 data). The 1051 data were not available in prior SWSI efforts.
- **CDSS tools:** The Technical Update made extensive use of modeling tools available through CDSS. CDSS is a water resources data and modeling toolbox developed by CWCB and DWR for each of Colorado's major river basins for regional planning purposes. Tools in CDSS include HydroBase (a vast database of statewide water-related data), geographic information systems (GIS) data, surface water allocation models, and models that quantify consumptive use from crops and other vegetation. CDSS tools are available in most basins in the state. In basins where particular CDSS tools are not available, alternative methodologies were used to estimate demands and potential future gaps. The level of detail on hydrology, operations, and demands is appropriate for regional planning but does not capture daily changes in streamflow, routing of reservoir releases, or non-typical operations. As a result, the effect of local water uses on streamflows may not always be fully captured by the regional models.

Click this link for more information on Colorado's Decision Support Systems: [Colorado's Decision Support Systems]

- **Consideration of climate change:** The effects of climate change significantly influence hydrology, water demand and availability, and estimated gaps. Three of the five planning scenarios include assumptions and projections related to a hotter and drier future climate.[1] The analyses considered temperature increases up to 4.2 degrees Fahrenheit and were consistent with projections in the Colorado Climate Plan. Projections of future climate change conditions were not a part of past SWSI analyses.
- **Quantification of an agricultural gap:** Water demands and shortages for irrigated crops at the field level were estimated in SWSI 2010 but were not quantified using surface water modeling. Using the full suite of modeling tools available from CDSS made it possible to estimate agricultural gaps in the Technical Update under current and planning scenario conditions. Agricultural gaps are described in two ways:
  1. **Total Gap:** The overall shortage of water supplies (current plus potential incremental increases) to meet agricultural diversion demands required to provide full crop consumptive uses.
  2. **Incremental Gap:** The degree to which the gap could increase beyond what agriculture currently experiences under water shortage conditions.



[1] The planning scenarios developed for the Colorado Water Plan and the Technical Update were built on the foundational work of the multi-phase Colorado River Water Availability Study, Phase II (CRWAS-II). Detailed methodology and analysis results can be found in CRWAS-II Task 7: Climate Change Approach and Results.

- **Improved environment and recreation tools:** The Technical Update improved the data associated with environment and recreation attributes statewide. In addition, the Colorado Environmental Flow Tool (Flow Tool) was developed by CWCB to help assess potential flow conditions and associated ecological health in river segments in each basin. The Flow Tool was built on the framework of the Watershed Flow Evaluation Tool, a Colorado-specific application of a framework for assessing environmental flow needs at a regional scale. The tool uses flow data from the surface water allocation modeling developed for the Technical Update.

Link for the **Colorado Environmental Flow Tool**

Risk of Future Water Shortages

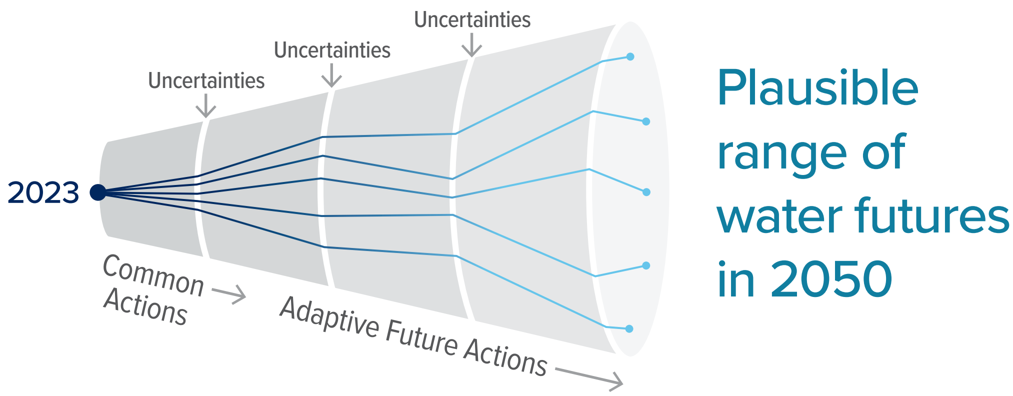
In the Technical Update, the calculated difference between water supplies and water demands for current and future conditions in the municipal and industrial and agriculture sectors was labeled the "gap." Gaps were presented for each of the five planning scenarios to reflect future uncertainty. Because gaps are estimated for future scenarios, they represent a future risk that water supplies will not be adequate to fully meet municipal, industrial, and agricultural demands. The bigger the gap, the higher the risk that Colorado will not be able to meet its future water needs. In a similar vein, potential future risks for environmental and recreational attributes based on projected future flow conditions were evaluated in the Technical Update using the Flow Tool.

Identifying potential future risks to all sectors of water use was a key objective of the Technical Update. Risk identification is a starting point and is foundational for discussions about projects and strategies that will help lessen future risk. Chapter 3 of the Water Plan summarizes the results of analyses conducted during the Technical Update and enhanced during the BIP update process.

The Water Plan uses scenario planning to identify and assess several potential water futures that together capture the most relevant uncertainties and driving forces

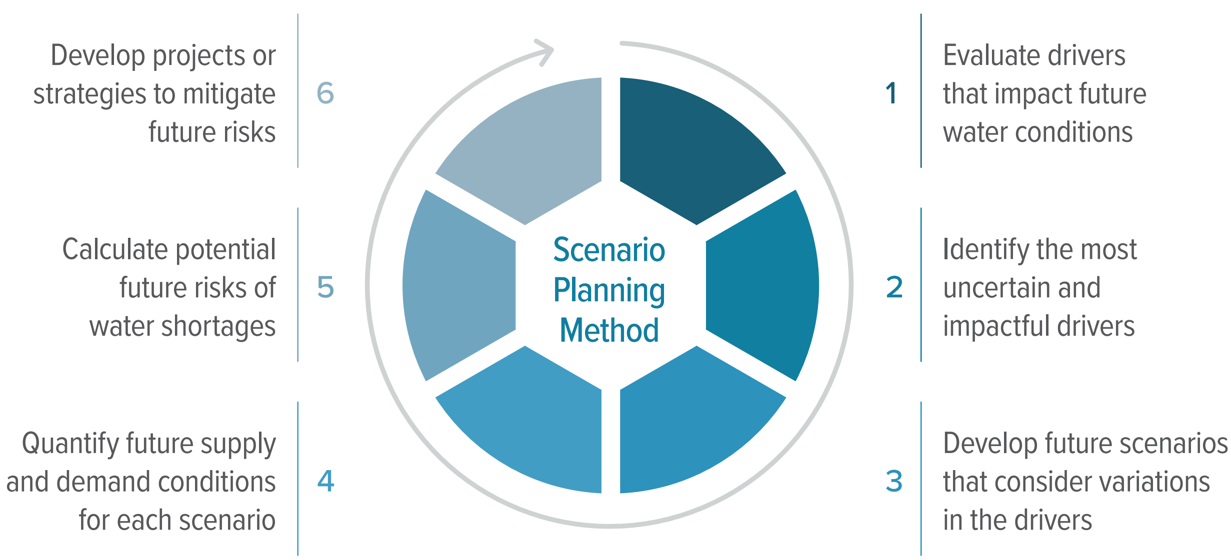
SCENARIO PLANNING APPROACH

The scenario planning process acknowledges that uncertainties exist in the future environmental state and social values of Colorado. As the time horizon increases, the uncertainty of these conditions increases as well. Particular scenarios can be based on assumptions about the states of future conditions. The scenario planning method is more sophisticated than a simplistic application of high-, medium-, and low-stress conditions (as were used in SWSI 2010).



The Water Plan uses scenario planning to consider a wide range of possible futures according to the best available science and stakeholder input. The approach considers uncertainties in future climate conditions, social conditions (such as values and economics), and supply-demand conditions (e.g., energy, agricultural, and municipal needs).

The scenario planning method included the six general steps described below and is intended to be cyclical and adaptive.



IDENTIFICATION OF HIGH-IMPACT DRIVERS THAT INFLUENCE COLORADO'S WATER FUTURE

Before developing the 2015 Water Plan, CWCB initiated a multi-year stakeholder dialogue in conjunction with the nine basin roundtables and the IBCC to develop a methodology for projecting future water needs. The IBCC then developed a list of the following nine high-impact drivers that could greatly influence the direction of Colorado's water future. Several of these drivers are interrelated and can have integrated effects. The identification and monitoring of these nine drivers are important to understanding the direction of future water supply and demand.

1. SOCIAL / ENVIRONMENTAL VALUES

DRIVER DESCRIPTION

Social/environmental values reflect the public's perception of water use, support of water and energy conservation, and allocation of water supply toward environmental uses. Social values influence drivers such as regulations and adoption of water efficiency technologies, but they also affect the types of solutions that Coloradans pursue to meet future water needs or respond to climate change. For example, social values can impact the degree to which residents voluntarily adopt water-efficient technologies that may cost them money. They can also influence the demand for local agricultural products and the desire to maintain open space. Personal experiences, education, and outreach impact the degree of public awareness of water issues, which in turn can affect the public's perception of the water supply solutions as well as recreation and environmental protections that are pursued.

IMPACT ON WATER RESOURCES

If values trend toward greater water and energy conservation, new technologies may emerge that help conserve water. Also, development of new supplies may occur in ways that meet municipal and agricultural needs while preserving or enhancing the environment and providing recreational benefits.

2. POPULATION / ECONOMIC GROWTH

DRIVER DESCRIPTION

Population growth is driven by both state and national economic trends and land use planning and development statewide (see Driver #3). Colorado's moderate climate and quality of life draw both permanent residents and tourists. Population and economic growth/decline is forecasted by the State Demography Office (SDO) using census data and understanding of economic drivers.

IMPACT ON WATER RESOURCES

Population growth is a primary driver for municipal water demand and urbanization. Population change directly influences water use, while economic growth influences the types of water use (municipal, industrial, recreation, etc.). While Colorado's recent efforts to save water though efficiency and conservation have kept water demands steady in spite of growth, water demands are nevertheless projected to increase.

3. URBAN LAND USE / URBAN GROWTH PATTERNS

DRIVER DESCRIPTION

Urban land use and growth considers both density of development, as well as urbanization of undeveloped and agricultural lands. Zoning and other decisions affecting population density in cities and towns impacts how water is used inside and outside of single- and multi-family housing. It also impacts the degree to which urban sprawl may occur in the future.

IMPACT ON WATER RESOURCES

Population growth patterns can impact availability of water resources and how local governments use water (in-house use versus watering of green spaces). As urban areas grow into undeveloped areas of the watershed, both runoff into streams and water quality are affected. Finally, the urbanization of agricultural lands results in a shift of water use from the agricultural sector to the municipal sector, which can impact timing of use and return flows, wildlife habitat, and overall watershed health.

4. AVAILABILITY OF WATER EFFICIENCY TECHNOLOGIES

DRIVER DESCRIPTION

Availability and adoption of water efficiency technology drives water demands from municipal, industrial, and agricultural perspectives. Increased efficiency can be implemented in all sectors (municipal, industrial, energy, agricultural) and can offset growth through decreased demand by individual users.

IMPACT ON WATER RESOURCES

Indoor municipal demands can be reduced by installing low-flow fixtures, and outdoor demands are influenced by types of landscaping and efficiency of irrigation systems. On the agricultural side, irrigation efficiency technologies can reduce water losses on-farm and in ditches that deliver water from rivers and streams to farms. In addition, crop hybrids that are drought tolerant and crops that require less water can reduce irrigation demand.

5. CLIMATE CHANGE / WATER SUPPLY AVAILABILITY

DRIVER DESCRIPTION

Climate change is the long-term shift in temperature and regional weather patterns that results in a range of projected future conditions that include a warmer and potentially drier future for Colorado.

IMPACT ON WATER RESOURCES

Climate conditions impact both water supplies and water demands. Climate change may decrease streamflows and/or shift yearly streamflow patterns, which would impact agricultural, municipal, and industrial water supplies and create or increase risks for environment and recreation attributes. Higher temperatures associated with climate change will increase irrigation water demands for agricultural crops and outdoor urban landscapes and result in reduced return flows to streams.

6. LEVEL OF REGULATORY OVERSIGHT / CONSTRAINT

DRIVER DESCRIPTION

Regulatory oversight includes the legal framework in Colorado and nationwide through which water is administered, developed, and managed. This includes oversight from DWR, Colorado Department of Public Health & Environment (CDPHE), U.S. Environmental Protection Agency (EPA), and others.

IMPACT ON WATER RESOURCES

Regulatory constraints are influenced by social values, and they may drive changes in demands. For example, industrial water needs for energy extraction or thermoelectric energy production may be higher or lower in the future depending on state and local regulations and policies. Regulation can also drive the types of water supply solutions that stakeholders pursue. For example, the efficiency of permitting for certain types of water projects and the associated environmental mitigation requirements could influence their feasibility and cost.

7. AGRICULTURAL ECONOMICS / WATER DEMAND

DRIVER DESCRIPTION

Agricultural conditions, such as the amount of irrigated land in production, crops grown, and climate influence irrigation water demands. Urbanization, municipal transfers of agricultural water supply, and availability of surface and groundwater supplies all influence the amount of agricultural land that will be in production in the future. In addition, demands and prices for local agricultural products affect the economic sustainability of continued agriculture and resulting demands for water.

IMPACT ON WATER RESOURCES

Changes in the economics of the agricultural sector may impact the amount and types of crops grown, as well as the amount of land under irrigation. These changes will impact water demands for agricultural purposes.

8. ENERGY ECONOMICS / WATER DEMAND

DRIVER DESCRIPTION

The energy sector uses water in a variety of ways, including direct use for hydropower, or indirect uses such as steam generation or cooling. Water needs for energy expand relative to population growth and current regulations, policies, and planning for the energy industry. These needs are also affected by the type of energy production that is used in the future and can be influenced by state and national energy policies.

IMPACT ON WATER RESOURCES

As the sources of energy shift from non-renewable (coal and gas) to renewable (water, wind, and solar), the demand for water will shift as well. It is anticipated that renewable sources of energy will be less water consumptive.

9. MUNICIPAL AND INDUSTRIAL WATER DEMANDS

DRIVER DESCRIPTION

The municipal and industrial sector serves the residents and businesses of Colorado with water. Municipal water demands are influenced by changes in other drivers such as population, urban land use, adoption of conservation measures, and climate.

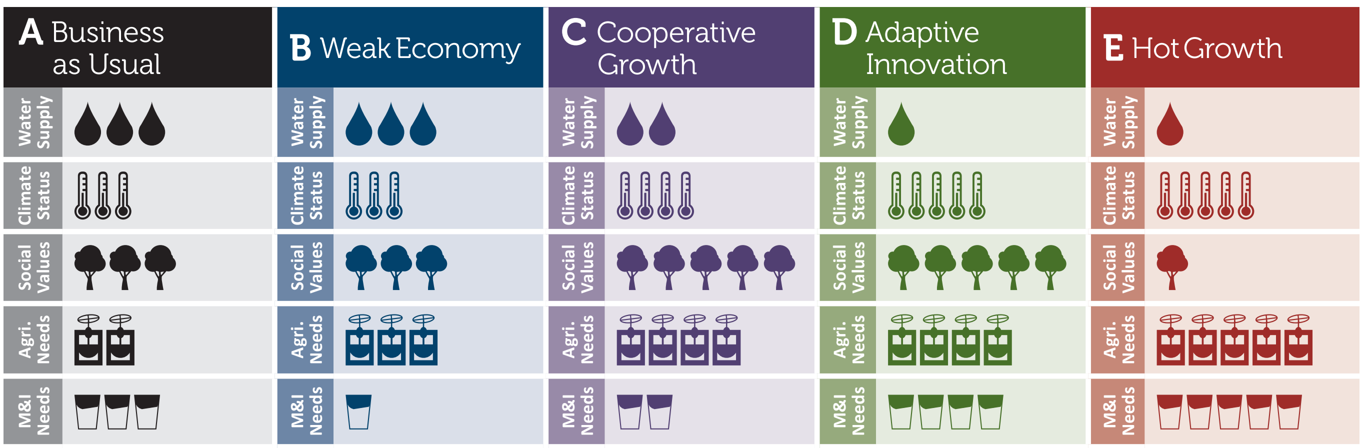
IMPACT ON WATER RESOURCES

Water in Colorado is scarce, and as the population grows, increased municipal and industrial demand for water is met through development of new supplies (if available), at the expense of water from a different sector, or through water conservation.

Using these drivers, the IBCC developed five scenarios that represent how Colorado's water future might look in 2050, knowing that the future is unpredictable and will contain a mix of multiple scenarios. A simplified graphic and descriptions of the five scenarios are shown below. The icons for each scenario illustrate the increase and decrease in levels for the generalized drivers compared to current levels (the five icons represent the combined effects of the nine drivers). The scenario names portray the overall story that each scenario tells in its respective views of the future.

Click this link for more information on the scenarios (including full text descriptions of each scenario). Refer to the Technical Update to the Water Plan, Sections 2.1.3 and 2.1.4: **Analysis and Technical Update**

SIMPLIFIED DESCRIPTION OF PLANNING SCENARIOS



A Business as Usual

- Population growth increases at trends predicted by the SDO.
- Future hydrology, per capita water demands, and adoption of conservation measures are similar to what's recently occurred.

B Weak Economy

- The world's economy slows, and the state's population growth is less than predicted.
- Hydrology is similar to recent patterns.
- This scenario puts the least amount of stress on future water supplies and is a bookend for scenarios.

C Cooperative Growth

- Climate is moderately warmer, and irrigation demands increase.
- Statewide population is similar to predictions by SDO, but it is distributed differently across the state.
- People seek to offset increased demands by more aggressively adopting water conservation.

D Adaptive Innovation / E Hot Growth

- Both scenarios assume that the climate is much warmer and drier and that population growth is higher than projected.
- The scenarios' primary differences revolve around conservation. In the Adaptive Innovation scenario, the state aggressively adopts conservation measures in both municipal and agricultural sectors. In the Hot Growth scenario, conservation is not a focus.

Monitoring the Drivers

The Water Plan will be updated periodically as part of a robust planning cycle to evaluate the state's changing water conditions. Part of the periodic update process will include monitoring the status of water resources drivers and adjusting the planning scenarios based on observed trends. Some of the drivers (e.g., population, per capita municipal and industrial water demands) can be monitored with readily available data being collected by state and local entities. Other drivers (e.g., regulatory constraints and social/environmental values) may require specific data gathering, such as surveys or collaboration with other entities who collect these types of information.

The interactions of drivers and their impact on risk is complex, which underscores the need for consistent monitoring of the drivers during Water Plan implementation. If certain drivers increase future demand (e.g., urban or energy sector growth) or decrease water supply (e.g., drier climate, increased regulation), then the risk of a future water shortage may increase; however, the risk may not increase if new water-efficient technologies emerge.

Monitoring and Uncertainty

Our future is uncertain, which is why monitoring is critical for identifying trends and adaptively planning for the future. For example, using SDO population projections developed in 2017 as a foundation, the Technical Update estimated a 2050 statewide population range of 7.7 million to 9.3 million. The SDO estimate, prepared in October 2022, projects a 2050 population of 7.5 million, which corresponds closely to the projection in the Weak Economy scenario. Trends in population and other water supply and demand drivers need to be monitored so that the Water Plan can adapt to uncertain and changing future conditions. The CWCB monitors drivers, identifies changes in drivers during Technical Updates, evaluates whether recent changes signal long-term trends, and assesses how trends may affect the future.

Actions can be taken that are useful in any future scenario

Near-term strategies and actions can be taken that provide benefits regardless of how the future unfolds (also known as "low regret strategies"). As future Technical Updates are conducted and the Water Plan is updated, new near-term strategies will be developed to adapt to conditions and lower our water-related risks.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-25-14

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-53:
Colorado Sun Article

In Colorado town built on coal, some families are moving on, even as Trump tries to boost industry

coloradosun.com/2025/12/08/colorado-coal-transition-jobs/

The Associated PressNews Agency, More by The Associated Press December 8, 2025

Matthew, Anna, Nathan and Matt Cooper prepare to drill a hole for a geothermal heat pump installation Thursday, Oct. 9, 2025, in Hamilton, Colo. (AP Photo/Brittany Peterson)

By Brittany Peterson and Jennifer McDermott, *The Associated Press*

CRAIG — The Cooper family knows how to work heavy machinery. The kids could run a hay baler by their early teens, and two of the three ran monster-sized drills at the coal mines along with their dad.

But learning to maneuver the shiny red drill they use to tap into underground heat feels different. It's a critical part of the new family business, High Altitude Geothermal, which installs geothermal heat pumps that use the Earth's constant temperature to heat and cool buildings. At stake is not just their livelihood but a century-long family legacy of producing energy in Moffat County.

Like many families here, the Coopers have worked in coal for generations — and in oil before that. That's ending for Matt Cooper and his son Matthew as one of three coal mines in the area closes in a statewide shift to cleaner energy.

"People have to start looking beyond coal," said Matt Cooper. "And that can be a multitude of things. Our economy has been so focused on coal and coal-fired power plants. And we need the diversity."

Many countries and about half of U.S. states are moving away from coal, citing environmental impacts and high costs. Burning coal emits carbon dioxide that traps heat in the atmosphere, warming the planet.

President Donald Trump has boosted coal as part of his agenda to promote fossil fuels. He's trying to save a declining industry with executive orders, large sales of coal from public lands, regulatory relief and offers of hundreds of millions of dollars to restore coal plants.

A drill sits outside the Cooper family ranch as they work to install a geothermal heat pump Thursday, Oct. 9, 2025, in Hamilton, Colo. (AP Photo/Brittany Peterson)

That's created uncertainty in places like Craig. As some families like the Coopers plan for the next stage of their careers, others hold out hope Trump will save their plants, mines and high-paying jobs.

Matt and Matthew Cooper work at the Colowyo Mine near Meeker, though active mining has ended and site cleanup begins in January.

The mine employs about 130 workers and supplies Craig Generating Station, a 1,400-megawatt coal-fired plant. Tri-State Generation and Transmission Association is planning to close Craig's Unit 1 by year's end for economic reasons and to meet legal requirements for reducing emissions. The other two units will close in 2028.

Xcel Energy owns coal-fired Hayden Station, about 30 minutes away. It said it doesn't plan to change retirement dates for Hayden, though it's extending another coal unit in Pueblo in part due to increased demand for electricity.

The Craig and Hayden plants together employ about 200 people.

Craig residents have always been entrepreneurial and that spirit will get them through this transition, said Kirstie McPherson, board president for the Craig Chamber of Commerce. Still, she said, just about everybody here is connected to coal.

"You have a whole community who has always been told you are an energy town, you're a coal town," she said. "When that starts going away, beyond just the individuals that are having the identity crisis, you have an entire culture, an entire community that is also having that same crisis."

Phasing out coal

Coal has been central to Colorado's economy since before statehood, but it's generally the most expensive energy on today's grid, said Democratic Gov. Jared Polis.

"We are not going to let this administration drag us backwards into an overreliance on expensive fossil fuels," Polis said in a statement.

Nationwide, coal power was 28% more expensive in 2024 than it was in 2021, costing consumers $6.2 billion more, according to a June analysis from Energy Innovation. The nonpartisan think tank cited significant increases to run aging plants as well as inflation.

Colorado's six remaining coal-fired power plants are scheduled to close or convert to natural gas, which emits about half the carbon dioxide as coal, by 2031. The state is rapidly adding solar and wind that's cheaper and cleaner than legacy coal plants. Renewable energy provides more than 40% of Colorado's power now and will pass 70% by the end of the decade, according to statewide utility plans.

Matt Cooper and his kids Anna, Nathan and Matthew prepare to drill a hole for a geothermal heat pump installation Thursday, Oct. 9, 2025, in Hamilton, Colo. (AP PhotoBrittany Peterson)

Nationwide, wind and solar growth has remained strong, producing more electricity than coal in 2025, as of the latest data in October, according to energy think tank Ember.

But some states want to increase or at least maintain coal production. That includes top coal state Wyoming, where the Wyoming Energy Authority said Trump is breathing welcome new life into its coal and mining industry.

Planning for the future

The Coopers have gone all-in on geothermal.

“Maybe we’ll never go back to coal,” Matt Cooper said. “We haven’t (gone) back to oil and gas, so we might just be geothermal people for quite some time, maybe generations, and then eventually something else will come along.”

While the Coopers were learning to use their drill in October, Wade Gerber was in downtown Craig distilling grain neutral spirits — used to make gin and vodka — on a day off from the Craig Station power plant. Gerber stepped over his corgis, Ali and Boss, and onto a stepladder to peer into a massive stainless steel pot where he was heating wheat and barley.

Gerber’s spent three decades in coal. When closure plans were announced four years ago, he, his wife Tenniel and their friend McPherson brainstormed business ideas.

The Craig Station coal-burning power plant in Moffat County, here on Feb. 14, 2024, is expected to close in a few years. (Hugh Carey, The Colorado Sun)

“With my background in plumbing and electrical from the plant it’s like, oh yeah, I can handle that part of it,” Gerber said about distilling. “This is the easy part.”

He used Tri-State’s education subsidies for classes in distilling, while other co-workers learned to fix vehicles or repair guns to find new careers. While some plan to leave town, Gerber is opening Bad Alibi Distillery. McPherson and Tenniel Gerber are opening a cocktail bar next door.

Everyone in town hopes Trump will step in to extend the plant’s life, Gerber said. Meanwhile, they’re trying to define a new future for Craig in a nerve-wracking time.

“For me, my products can go elsewhere. I don’t necessarily have to sell it in Craig, there’s that avenue. For someone relying on Craig, it’s even scarier,” he said.

Questioning the coal rollback

Tammy Villard owns a gift shop, Moffat Mercantile, with her husband. After the coal closures were announced, they opened a commercial print shop too, seeing it as a practical choice for when so many high-paying jobs go away.

Villard, who spent a decade at Colowyo as administrative staff, said she doesn't understand how the state can throw the switch to turn off coal and still have reliable electricity. She wants the state to slow down.

Villard describes herself as a moderate Republican. She said political swings at the federal level — from the green energy push in the last administration to doubling down on fossil fuels in this one — aren't helpful.

"The pendulum has to come back to the middle," she said, "and we are so far out to either side that I don't know how we get back to that middle."

Type of Story: News Service

Produced externally by an organization we trust to adhere to high journalistic standards.

The Associated PressNews Agency

The Associated Press is an independent, not-for-profit news cooperative, serving member newspapers and broadcasters in the U.S., and other customers around the world. The Colorado Sun is proud to be one of them. AP journalists in more... More by The Associated Press

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Tri-State	)	Order No. 202-25-14
Generation and Transmission	)	
Association, Platte River Power	)	
Authority, Salt River Project,	)	
PacifiCorp, and Xcel Energy	)	

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-54:
PacifiCorp FERC Form 1

THIS FILING IS
Item 1: ☑ An Initial (Original) Submission OR ☐ Resubmission No.

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company) PacifiCorp	Year/Period of Report End of: 2024/ Q4

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q) is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities, Licensees, and Others Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

one million megawatt hours of total annual sales,

100 megawatt hours of annual sales for resale,

500 megawatt hours of annual power exchanges delivered, or

500 megawatt hours of annual wheeling for others (deliveries plus losses).

What and Where to Submit

Submit FERC Form Nos. 1 and 3-Q electronically through the eCollection portal at https://eCollection.ferc.gov, and according to the specifications in the Form 1 and 3-Q taxonomies.

The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:
Secretary
Federal Energy Regulatory Commission 888 First Street, NE
Washington, DC 20426

For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Schedules	Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of [COMPANY NAME] for the year ended on which we have reported separately under date of [DATE], we have also reviewed schedules [NAME OF SCHEDULES] of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases." The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. Further instructions are found on the Commission's website at https://www.ferc.gov/ferc-online/ferc-online/frequently-asked-questions-faqs-efilingferc-online.

Federal, State, and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from https://www.ferc.gov/general-information-0/electric-industry-forms.

When to Submit

FERC Forms 1 and 3-Q must be filed by the following schedule:

FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,168 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is

For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

Enter the month, day, and year for all dates. Use customary abbreviations. The "Date of Report" included in the header of each page is to be completed only for resubmissions (see VII. below).

Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

For any resubmissions, please explain the reason for the resubmission in a footnote to the data field.

Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

Schedule specific instructions are found in the applicable taxonomy and on the applicable blank rendered form.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and" firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

'Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

'Person' means an individual or a corporation;

'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; ......

"project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

'To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304.

Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may by rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports shall be made, and require from estimated to average 168 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309.

The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

GENERAL PENALTIES

The Commission may assess up to $1 million per day per violation of its rules and regulations. See FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

FERC FORM NO. 1
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent PacifiCorp	02 Year/ Period of Report End of: 2024/ Q4

03 Previous Name and Date of Change (If name changed during year)

/

04 Address of Principal Office at End of Period (Street, City, State, Zip Code)

825 N.E. Multnomah Street, Suite 1900, Portland, OR 97232

05 Name of Contact Person Jennifer Kahl	06 Title of Contact Person External Reporting Director

07 Address of Contact Person (Street, City, State, Zip Code)

825 N.E. Multnomah Street, Suite 1900, Portland, OR 97232

08 Telephone of Contact Person, Including Area Code (503) 813-5784	09 This Report is An Original / A Resubmission (1) ☑ An Original (2) ☐ A Resubmission	10 Date of Report (Mo, Da, Yr) 04/15/2025

Annual Corporate Officer Certification

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name Nikki L. Kobliha	03 Signature /s/ Nikki L. Kobliha	04 Date Signed (Mo, Da, Yr) 04/15/2025
02 Title Senior Vice President and Chief Financial Officer		

Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Name of Respondent: PacifiCorp	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2025	Year/Period of Report End of: 2024/ Q4

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

40	**Accumulated Deferred Income Taxes-Other**	276	
41	**Other Regulatory Liabilities**	278	
42	**Electric Operating Revenues**	300	
43	**Regional Transmission Service Revenues (Account 457.1)**	302	N/A
44	**Sales of Electricity by Rate Schedules**	304	
45	**Sales for Resale**	310	
46	**Electric Operation and Maintenance Expenses**	320	
47	**Purchased Power**	326	
48	**Transmission of Electricity for Others**	328	
49	**Transmission of Electricity by ISO/RTOs**	331	N/A
50	**Transmission of Electricity by Others**	332	
51	**Miscellaneous General Expenses-Electric**	335	
52	**Depreciation and Amortization of Electric Plant (Account 403, 404, 405)**	336	
53	**Regulatory Commission Expenses**	350	
54	**Research, Development and Demonstration Activities**	352	N/A
55	**Distribution of Salaries and Wages**	354	
56	**Common Utility Plant and Expenses**	356	N/A
57	**Amounts included in ISO/RTO Settlement Statements**	397	
58	**Purchase and Sale of Ancillary Services**	398	
59	**Monthly Transmission System Peak Load**	400	
60	**Monthly ISO/RTO Transmission System Peak Load**	400a	N/A
61	**Electric Energy Account**	401a	
62	**Monthly Peaks and Output**	401b	
63	**Steam Electric Generating Plant Statistics**	402	
64	**Hydroelectric Generating Plant Statistics**	406	
65	**Pumped Storage Generating Plant Statistics**	408	N/A
66	**Generating Plant Statistics Pages**	410	
66.1	**Energy Storage Operations (Large Plants)**	414	N/A
66.2	**Energy Storage Operations (Small Plants)**	419	N/A
67	**Transmission Line Statistics Pages**	422	
68	**Transmission Lines Added During Year**	424	
69	**Substations**	426	
70	**Transactions with Associated (Affiliated) Companies**	429	
71	**Footnote Data**	450	
	Stockholders' Reports (check appropriate box)		
	Stockholders' Reports Check appropriate box: ☑ Two copies will be submitted ☐ No annual report to stockholders is prepared		

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

Nikki L. Kobliha

Senior Vice President and Chief Financial Officer

825 N.E. Multnomah Street, Suite 1900, Portland, OR 97232

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

PacifiCorp was initially incorporated in 1910 under the laws of the state of Maine under the name Pacific Power & Light Company. In 1984, Pacific Power & Light Company changed its name to PacifiCorp. In 1989, it merged with Utah Power and Light Company, a Utah corporation, in a transaction wherein both corporations merged into a newly formed Oregon corporation. The resulting Oregon corporation was re-named PacifiCorp, which is the operating entity today.

State of Incorporation:

Date of Incorporation:

Incorporated Under Special Law:

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

Not applicable.

(a) Name of Receiver or Trustee Holding Property of the Respondent:

(b) Date Receiver took Possession of Respondent Property:

(c) Authority by which the Receivership or Trusteeship was created:

(d) Date when possession by receiver or trustee ceased:

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

PacifiCorp is a United States regulated electric utility company headquartered in Oregon that serves approximately 2.1 million retail electric customers, including residential, commercial, industrial, irrigation and other customers in portions of Utah, Oregon, Wyoming, Washington, Idaho and California. PacifiCorp is principally engaged in the business of generating, transmitting, distributing and selling electricity. In addition to retail sales, PacifiCorp buys and sells electricity on the wholesale market with other utilities, energy marketing companies, financial institutions and other market participants. PacifiCorp delivers electricity to customers in Utah, Wyoming and Idaho under the trade name Rocky Mountain Power and to customers in Oregon, Washington and California under the trade name Pacific Power.

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

(1) ☐ Yes

(2) ☑ No

Name of Respondent: PacifiCorp	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/15/2025	Year/Period of Report End of: 2024/ Q4

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the respondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiaries for whom trust was maintained, and purpose of the trust.

Berkshire Hathaway Inc.
Berkshire Hathaway Energy Company ("BHE") (wholly owned by Berkshire Hathaway, Inc.)
PPW Holdings LLC (wholly owned by BHE)
PacifiCorp (wholly owned by PPW Holdings LLC)

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Commission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

PACIFICORP
NOTES TO FINANCIAL STATEMENTS

(1) Organization and Operations

PacifiCorp is a United States ("U.S.") regulated electric utility company serving retail customers, including residential, commercial, industrial, irrigation and other customers in portions of Utah, Oregon, Wyoming, Washington, Idaho and California. PacifiCorp owns, or has interests in, a number of thermal, hydroelectric, wind-powered and geothermal generating facilities, as well as electric transmission and distribution assets. PacifiCorp also buys and sells electricity on the wholesale market with other utilities, energy marketing companies, financial institutions and other market participants. PacifiCorp is subject to comprehensive state and federal regulation. PacifiCorp is an indirect subsidiary of Berkshire Hathaway Energy Company ("BHE"), a holding company based in Des Moines, Iowa that has investments in subsidiaries principally engaged in energy businesses. BHE is a wholly owned subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway").

(2) Summary of Significant Accounting Policies

Basis of Presentation

These financial statements are prepared in accordance with the requirements of the Federal Energy Regulatory Commission ("FERC") as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America ("GAAP"). These notes include certain applicable disclosures required by GAAP adjusted to the FERC basis of presentation and include specific information requested by the FERC.

The following are the significant differences between the FERC accounting and reporting standards and GAAP.

Investments in Subsidiaries

In accordance with FERC Order No. AC11-132, PacifiCorp accounts for its investment in subsidiaries using the equity method for FERC reporting purposes rather than consolidating the assets, liabilities, revenues and expenses of subsidiaries as required by GAAP. GAAP requires that entities in which a company holds a controlling financial interest be consolidated. Also in accordance with FERC Order No. AC11-132, PacifiCorp does not eliminate intercompany profit on transactions with equity investees as would be required under GAAP. The accounting treatment described above has no effect on net income or the combined retained earnings of PacifiCorp and undistributed earnings of subsidiaries.

Costs of Removal

Estimated removal costs that are recovered through approved depreciation rates, but that do not meet the requirements of a legal asset retirement obligation ("ARO") are reflected in the cost of removal regulatory liability under GAAP and as accumulated provision for depreciation under the FERC accounting and reporting standards.

Income Taxes

Accumulated deferred income taxes are classified as net non-current assets or liabilities on the balance sheet for GAAP. Under the FERC accounting and reporting standards, accumulated deferred income taxes are classified as gross non-current assets and gross non-current liabilities. Additionally, there are certain presentational differences between FERC and GAAP for amounts related to unrecognized tax benefits associated with temporary differences in accordance with FERC guidance. For GAAP, unrecognized tax benefits associated with temporary differences are reflected as other liabilities while for FERC the income tax impact of uncertain tax positions associated with temporary differences are reflected in accumulated deferred income taxes.

Interest and penalties on income taxes for GAAP are classified as income tax expense. All such amounts are classified as interest income, interest expense and penalties under the FERC accounting and reporting standards.

Pensions and Postretirement Benefits Other Than Pensions

Pension and postretirement benefits other than pensions ("PBOP") are comprised of several different components of net periodic benefit costs. As required by GAAP, the service cost component is reported with other compensation costs arising from services rendered by employees, while the other components of net periodic benefit costs are presented outside of operating income. Additionally, only the service cost component of net periodic benefit costs is eligible for capitalization under GAAP. In accordance with FERC guidance, PacifiCorp continues to report the components of net periodic benefit costs for pension and PBOP on the statement of income and follows GAAP guidance to capitalize only the service cost component of net periodic benefit costs.

Reclassifications

Certain other reclassifications of balance sheet, income statement and cash flow amounts have been made in order to conform to the FERC basis of presentation. These reclassifications had no effect on net income.

Use of Estimates in Preparation of Financial Statements

The preparation of the financial statements in conformity with the FERC and GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the period. These estimates include, but are not limited to, the effects of regulation; certain assumptions made in accounting for pension and other postretirement benefits; AROs; income taxes; unbilled revenue; valuation of certain financial assets and liabilities, including derivative contracts; and accounting for loss contingencies and applicable insurance recoveries, including those related to the Oregon and Northern California 2020 wildfires (the "2020 Wildfires") and a wildfire that began in the Oak Knoll Ranger District of the Klamath National Forest in Siskiyou County, California in July 2022 (the "2022 McKinney Fire"), referred to together as "the Wildfires" as discussed in Note 14. Actual results may differ from the estimates used in preparing the financial statements.

Accounting for the Effects of Certain Types of Regulation

PacifiCorp prepares its financial statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, PacifiCorp defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in rates occur.

If it becomes no longer probable that the deferred costs or income will be included in future rates, the related regulatory assets and liabilities will be recognized in net income, returned to customers or re-established as accumulated other comprehensive income (loss) ("AOCI").

Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability between market participants in the principal market or in the most advantageous market when no principal market exists. Adjustments to transaction prices or quoted market prices may be required in illiquid or disorderly markets in order to estimate fair value. Different valuation techniques may be appropriate under the circumstances to determine the value that would be received to sell an asset or paid to transfer a liability in an orderly transaction. Market participants are assumed to be independent, knowledgeable, able and willing to transact an exchange and not under duress. Nonperformance or credit risk is considered when determining fair value. Considerable judgment may be required in interpreting market data used to develop the estimates of fair value. Accordingly, estimates of fair value presented herein are not necessarily indicative of the amounts that could be realized in a current or future market exchange.

Cash Equivalents and Restricted Cash and Cash Equivalents

Cash equivalents consist of funds invested in money market mutual funds, U.S. Treasury Bills and other investments with a maturity of three months or less when purchased. Cash and cash equivalents exclude amounts where availability is restricted by legal requirements, loan agreements or other contractual provisions. Restricted cash and cash equivalents included in other special funds consist substantially of funds representing vendor retention, nuclear decommissioning and custodial funds. A reconciliation of cash and cash equivalents and restricted cash equivalents as of December 31, 2024 and 2023 as presented on the Statements of Cash Flows is outlined below and disaggregated by the line items in which they appear on the Comparative Balance Sheets (in millions):

	2024	2023
Cash (131)	$ 20	$ 14
Other special funds (128)	16	53
Temporary cash investments (136)	21	114
Total cash and cash equivalents and restricted cash and cash equivalents	57	181

Investments

Available-for-sale securities are carried at fair value with realized gains and losses, as determined on a specific identification basis, recognized in earnings and unrealized gains and losses recognized in AOCI, net of tax. As of December 31, 2024 and 2023, PacifiCorp had no unrealized gains and losses on available-for-sale securities. Trading securities are carried at fair value with realized and unrealized gains and losses recognized in earnings.

Allowance for Credit Losses

Trade receivables are primarily short-term in nature with stated collection terms of less than one year from the date of origination, and are stated at the outstanding principal amount, net of an estimated allowance for credit losses. The allowance for credit losses is based on PacifiCorp's assessment of the collectability of amounts owed to PacifiCorp by its customers. This assessment requires judgment regarding the ability of customers to pay or the outcome of any pending disputes. In measuring the allowance for credit losses for trade receivables, PacifiCorp primarily utilizes credit loss history. However, PacifiCorp may adjust the allowance for credit losses to reflect current conditions and reasonable and supportable forecasts that deviate from historical experience. The changes in the balance of the allowance for credit losses, which is included in accumulated provision for uncollectible accounts on the Comparative Balance Sheet, is summarized as follows for the years ended December 31 (in millions):

	2024	2023
Beginning balance	$ 30	$ 19
Charged to operating costs and expenses, net	26	34
Write-offs, net	(34)	(23)
Ending balance	$ 22	$ 30

Derivatives

PacifiCorp employs a number of different derivative contracts, which may include forwards, options, swaps and other agreements, to manage price risk for electricity, natural gas and other commodities and interest rate risk. Derivative contracts are recorded on the Comparative Balance Sheet as either assets or liabilities and are stated at estimated fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by GAAP. Derivative balances reflect offsetting permitted under master netting agreements with counterparties and cash collateral paid or received under such agreements.

Commodity derivatives used in normal business operations that are settled by physical delivery, among other criteria, are eligible for and may be designated as normal purchases or normal sales. Normal purchases or normal sales contracts are not marked-to-market and settled amounts are recognized as operating revenue or operations expenses on the Statement of Income.

For PacifiCorp's derivative contracts, the settled amount is generally included in rates. Accordingly, the net unrealized gains and losses associated with interim price movements on contracts that are accounted for as derivatives and probable of inclusion in rates are recorded as regulatory liabilities or assets. For a derivative contract not probable of inclusion in rates, changes in the fair value are recognized in earnings.

Inventories

Inventories consist mainly of materials, supplies and fuel stocks and are stated at the lower of average cost or net realizable value.

Net Utility Plant

General

Additions to utility plant are recorded at cost. PacifiCorp capitalizes all construction-related material, direct labor and contract services, as well as indirect construction costs, which include debt and equity allowance for funds used during construction ("AFUDC"). The cost of additions and betterments are capitalized, while costs incurred that do not improve or extend the useful lives of the related assets are generally expensed.

Depreciation and amortization are generally computed on the straight-line method based on composite asset class lives prescribed by PacifiCorp's various regulatory authorities or over the assets' estimated useful lives. Depreciation studies are completed periodically to determine the appropriate composite asset class lives, net salvage and depreciation rates. These studies are reviewed and rates are ultimately approved by the various regulatory authorities. Net salvage includes the estimated future residual values of the assets and any estimated removal costs recovered through approved depreciation rates. Estimated removal costs are recorded as either accumulated provision for depreciation or an ARO liability on the Comparative Balance Sheet, depending on whether the obligation meets the requirements of an ARO. As actual removal costs are incurred, the associated accumulated provision for depreciation or ARO liability is reduced.

Generally when PacifiCorp retires or sells a component of regulated utility plant, it charges the original cost, net of any proceeds from the disposition, to accumulated provision for depreciation. Any gain or loss on disposals of all other assets is recorded through earnings.

Debt and equity AFUDC, which represents the estimated costs of debt and equity funds necessary to finance the construction of utility plant is capitalized as a component of utility plant, with offsetting credits to the Statement of Income. AFUDC is computed based on guidelines set forth by the FERC. After construction is completed, PacifiCorp is permitted to earn a return on these costs as a component of the related assets, as well as recover these costs through depreciation expense over the useful lives of the related assets.

Asset Retirement Obligations

PacifiCorp recognizes AROs when it has a legal obligation to perform decommissioning, reclamation or removal activities upon retirement of an asset. PacifiCorp's AROs are primarily associated with its generating facilities. The fair value of an ARO liability is recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made, and is added to the carrying amount of the associated asset, which is then depreciated over the remaining useful life of the asset. Subsequent to the initial recognition, the ARO liability is adjusted for any revisions to the original estimate of undiscounted cash flows (with corresponding adjustments to utility plant, net) and for accretion of the ARO liability due to the passage of time. The difference between the ARO liability, the corresponding ARO asset included in utility plant and amounts recovered in rates to satisfy such liabilities is recorded as a regulatory asset or liability.

Impairment

PacifiCorp evaluates long-lived assets for impairment, including utility plant, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or when the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the appropriate FERC accounts are adjusted to write down the asset to the estimated fair value and any resulting impairment loss is reflected on the Statement of Income. The impacts of regulation are considered when evaluating the carrying value of regulated assets.

Leases

PacifiCorp has non-cancelable operating leases primarily for land, office space, office equipment, and generating facilities and finance leases consisting primarily of office buildings, natural gas pipeline facilities, and vehicles. These leases generally require PacifiCorp to pay for insurance, taxes and maintenance applicable to the leased property. Given the capital intensive nature of the utility industry, it is common for a portion of lease costs to be capitalized when used during construction or maintenance of assets, in which the associated costs will be capitalized with the corresponding asset and depreciated over the remaining life of that asset. Certain leases contain renewal options for varying periods and escalation clauses for adjusting rent to reflect changes in price indices. PacifiCorp does not include options in its lease calculations unless there is a triggering event indicating PacifiCorp is reasonably certain to exercise the option. PacifiCorp's accounting policy is to not recognize right-of-use assets and lease obligations for leases with contract terms of one year or less and not separate lease components from non-lease components and instead account for each separate lease component and the non-lease components associated with a lease as a single lease component. Right-of-use assets will be evaluated for impairment in line with GAAP when a triggering event has occurred that might affect the value and use of the assets being leased.

PacifiCorp's leases of generating facilities generally are in the form of long-term purchases of electricity, also known as power purchase agreements ("PPA"). PPAs are generally signed before or during the early stages of project construction and can yield a lease that has not yet commenced. These agreements are primarily for renewable energy and the payments are considered variable lease payments as they are based on the amount of output.

PacifiCorp follows FERC accounting and reporting requirements and records operating and finance right-of-use assets in Account 101.1, Property under capital leases, and the current and noncurrent operating and finance lease liabilities in Account 243, Obligations under capital leases – Current and Account 227, Obligations under capital leases – Noncurrent, respectively.

Revenue Recognition

PacifiCorp uses a single five-step model to identify and recognize revenue from contracts with customers ("Customer Revenue") upon transfer of control of promised goods or services in an amount that reflects the consideration to which PacifiCorp expects to be entitled in exchange for those goods or services. PacifiCorp records sales, franchise and excise taxes collected directly from customers and remitted directly to the taxing authorities on a net basis on the Statement of Income.

Substantially all of PacifiCorp's Customer Revenue is derived from tariff-based sales arrangements approved by various regulatory commissions. These tariff-based revenues are mainly comprised of energy, transmission and distribution and have performance obligations to deliver energy products and services to customers which are satisfied over time as energy is delivered or services are provided.

Revenue recognized is equal to what PacifiCorp has the right to invoice as it corresponds directly with the value to the customer of PacifiCorp's performance to date and includes billed and unbilled amounts. Payments for amounts billed are generally due from the customer within 30 days of billing. Rates charged for energy products and services are established by regulators or contractual arrangements that establish the transaction price as well as the allocation of price amongst the separate performance obligations. When preliminary regulated rates are permitted to be billed prior to final approval by the applicable regulator, certain revenue collected may be subject to refund and classified in accordance with FERC accounting standards.

The determination of customer billings is based on a systematic reading of meters. At the end of each month, energy provided to customers since the date of the last meter reading is estimated, and the corresponding unbilled revenue is recorded. Factors that can impact the estimate of unbilled energy include, but are not limited to, seasonal weather patterns, total volumes supplied to the system, line losses, economic impacts and composition of sales among customer classes. Unbilled revenue is reversed in the following month and billed revenue is recorded based on the subsequent meter readings.

Unamortized Debt, Premiums, Discounts and Debt Issuance Costs

Premiums, discounts and debt issuance costs incurred for the issuance of long-term debt are amortized over the term of the related financing using the effective interest method.

Income Taxes

Berkshire Hathaway includes PacifiCorp in its U.S. federal income tax return. Consistent with established regulatory practice, PacifiCorp's provision for income taxes has been computed on a stand-alone basis.

Deferred income tax assets and liabilities are based on differences between the financial statement and income tax basis of assets and liabilities using enacted income tax rates expected to be in effect for the year in which the differences are expected to reverse. Changes in deferred income tax assets and liabilities associated with components of other comprehensive income ("OCI") are charged or credited directly to OCI. Changes in deferred income tax assets and liabilities associated with certain property-related basis differences and other various differences that PacifiCorp deems probable to be passed on to its customers in most state jurisdictions are charged or credited directly to a regulatory asset or liability and will be included in regulated rates when the temporary differences reverse or as otherwise approved by PacifiCorp's various regulatory commissions. Other changes in deferred income tax assets and liabilities are included as a component of income tax expense. Changes in deferred income tax assets and liabilities attributable to changes in enacted income tax rates are charged or credited to income tax expense or a regulatory asset or liability in the period of enactment. Valuation allowances are established when necessary to reduce deferred income tax assets to the amount that is more-likely-than-not to be realized.

Investment tax credits are deferred and amortized over the estimated useful lives of the related properties or as prescribed by various regulatory commissions.

PacifiCorp recognizes the tax benefit from an uncertain tax position only if it is more-likely-than-not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that is more-likely-than-not to be realized upon ultimate settlement.

Government Grants

From time to time, PacifiCorp enters into grant agreements with federal agencies, as well as agreements with third parties as a subrecipient of a federal grant, subjecting PacifiCorp to various federal compliance requirements. Most commonly these are cost share grants where PacifiCorp expenditures match the amount of grant proceeds. Grant proceeds most frequently support capital projects but are also used to cover operating costs. Grant proceeds received to reimburse capital project costs are applied as a direct offset to construction work-in-progress, ultimately serving to reduce PacifiCorp's investment in net utility plant. Grant proceeds received to reimburse operating costs are applied as an offset to operation expense.

Segment Information

PacifiCorp currently has one reportable segment, its regulated electric utility operations, which derives its revenue from regulated retail sales of electricity to residential, commercial, industrial and irrigation customers and from wholesale sales. PacifiCorp's chief operating decision maker ("CODM") is its Chief Executive Officer. The CODM uses net income, as reported on the Consolidated Statements of Operations in PacifiCorp's GAAP financial statements that are filed with the U.S. Securities and Exchange Commission ("Consolidated Statements of Operations"), and generally considers actual results versus historical results, budgets or forecasts, as well as unique risks and opportunities, when making decisions about the allocation of resources and capital. The segment expenses regularly provided to the CODM align with the captions presented on the Consolidated Statements of Operations. PacifiCorp's segment capital expenditures are reported on the Statement of Cash Flows as cash outflows for plant. PacifiCorp's segment assets are reported on the Comparative Balance Sheet as total assets.

New Accounting Pronouncements

In November 2023, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2023-07, Segment Reporting Topic 280, "Segment Reporting—Improvements to Reportable Segment Disclosures" which allows disclosure of one or more measures of segment profit or loss used by the chief operating decision maker to allocate resources and assess performance. Additionally, the standard requires enhanced disclosures of significant segment expenses and other segment items as well as incremental qualitative disclosures on both an annual and interim basis. This guidance is effective for annual reporting periods beginning after December 15, 2023, and interim reporting periods after December 15, 2024. Early adoption is permitted and retrospective application is required for all periods presented. PacifiCorp adopted this guidance for the fiscal year beginning January 1, 2024 under the retrospective method. The adoption did not have a material impact on PacifiCorp's financial statements and disclosures included within Notes to Financial Statements.

In December 2023, the FASB issued ASU No. 2023-09, Income Taxes Topic 740, "Income Tax—Improvements to Income Tax Disclosures" which requires enhanced disclosures, including specific categories and disaggregation of information in the effective tax rate reconciliation, disaggregated information related to income taxes paid, income or loss from continuing operations before income tax expense or benefit, and income tax expense or benefit from continuing operations. This guidance is effective for annual reporting periods beginning after December 15, 2024. Early adoption is permitted and should be applied on a prospective basis, however retrospective application is permitted. PacifiCorp is currently evaluating the impact of adopting this guidance on its financial statements and disclosures included within Notes to Financial Statements.

In November 2024, the FASB issued ASU No. 2024-03, Income Statement—Reporting Comprehensive Income—Expense Disaggregation Disclosures Subtopic 220-40, "Disaggregation of Income Statement Expenses" which addresses requests from investors for more detailed information about certain expenses and requires disclosure of the amounts of purchases of inventory, employee compensation, depreciation and intangible asset amortization included in each relevant expense caption presented on the income statement. This guidance is effective for annual reporting periods beginning after December 15, 2026 and interim reporting periods beginning after December 15, 2027. Early adoption is permitted and should be applied on a prospective basis, however retrospective application is permitted. PacifiCorp is currently evaluating the impact of adopting this guidance on its financial statements and disclosures included within Notes to Financial Statements.

Subsequent Events

PacifiCorp has evaluated the impact on its financial statements of events occurring after December 31, 2024 up to February 21, 2025, the date that PacifiCorp's GAAP financial statements were filed with the U.S. Securities and Exchange Commission and has updated such evaluation for disclosure purposes through April 15, 2025. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.

(3) Net Utility Plant

The average depreciation and amortization rate applied to depreciable utility plant was 3.2% and 3.4% for the years ended December 31, 2024 and 2023, respectively, including the impacts of $29 million and $29 million in 2024 and 2023, respectively, primarily related to Idaho's, Utah's, Wyoming's and Washington's shares of incremental decommissioning costs for certain coal-fueled units.

Government Grants

In November 2024, PacifiCorp accepted two cost share grants from the U.S. Department of Energy ("DOE") under the DOE's Grid Resilience and Innovation Partnerships ("GRIP") Program supported by the Infrastructure Investment and Jobs Act. The two GRIP grants will provide cash proceeds totaling approximately $150 million as cost reimbursements supporting PacifiCorp's investment in certain wildfire mitigation projects, such as system hardening for fire resistance and prevention and new substation infrastructure, and other investments in technologies that significantly enhance situational awareness to reduce or mitigate wildfires and improve electric grid flexibility, reliability and resiliency. The period of performance for both GRIP grants begins September 2024 and runs through September 2028 and 2029. No costs incurred after the period of performance will be eligible for reimbursement.

In conjunction with the two GRIP awards, the DOE and U.S. Department of Labor accepted PacifiCorp's request for a temporary exception regarding the Davis-Bacon Act weekly pay and certified payroll reporting requirements with which PacifiCorp is required to comply under the terms of the grants. The parties agreed to a curative plan that provides for a temporary means to achieve the goals of these requirements and allows PacifiCorp to have until April 1, 2026, to fully comply with these requirements.

Other current DOE cost share grants primarily support electric vehicle infrastructure programs and energy efficiency programs. The period of performance for the electric vehicle infrastructure grant ended December 2024, and was for total cash proceeds of $6 million. The period of performance for the energy efficiency grant ends May 2028, and is for total cash proceeds of $5 million.

On January 20, 2025, U.S. federal executive order entitled *Unleashing American Energy* was issued requiring federal agencies to immediately pause disbursement of federal funds appropriated under the Inflation Reduction Act of 2022 and the Infrastructure Investment and Jobs Act, subject to respective agency review within 90 days of the date of the order of the agency's processes, policies and programs for issuing grants consistent with the policies stated in the executive order. PacifiCorp is monitoring federal activities associated with the executive order to determine whether the funding associated with its grants will be impacted.

Various compliance requirements are associated with the DOE grants, including demonstration that the costs are allowable under the grants. In the event PacifiCorp fails to meet these requirements, it could be required to return funds to the DOE.

During the year ended December 31, 2024, approximately $11 million of federal grant funds reduced additions to net utility plant on the Comparative Balance Sheet and approximately $4 million of federal grant funds reduced operation and maintenance expenses on the Statement of Income. Federal grant funds received prior to 2024 were insignificant.

(4) Jointly Owned Utility Facilities

Under joint facility ownership agreements with other utilities, PacifiCorp, as a tenant in common, has undivided interests in jointly owned generation, transmission and distribution facilities. PacifiCorp accounts for its proportionate share of each facility, and each joint owner has provided financing for its share of each facility. Operating costs of each facility are assigned to joint owners based on their percentage of ownership or energy production, depending on the nature of the cost. Operating costs and expenses on the Statement of Income include PacifiCorp's share of the expenses of these facilities.

The amounts shown in the table below represent PacifiCorp's share in each jointly owned facility included in net utility plant as of December 31, 2024 (dollars in millions):

	PacifiCorp Share	Facility in Service	Accumulated Depreciation and Amortization	Construction Work-in-Progress
Jim Bridger Nos. 1 - 4	67%	$ 1,570	$ 1,030	$ 4
Hunter No. 1	94	509	256	3
Hunter No. 2	60	315	162	1
Wyodak	80	492	303	—
Colstrip Nos. 3 and 4	10	263	228	2
Hermiston	50	191	118	6
Craig Nos. 1 and 2	19	373	217	—
Hayden No. 1	25	77	58	—
Hayden No. 2	13	45	35	—
Transmission and distribution facilities	Various	932	351	308
Total		$ 4,767	$ 2,758	$ 324

(5) Leases

The following table summarizes PacifiCorp's leases recorded on the Comparative Balance Sheet as of December 31 (in millions):

	2024	2023
Right-of-use assets:		
Operating leases	$ 11	$ 12
Finance leases	24	12
Total right-of-use assets	$ 35	$ 24
Lease liabilities:		
Operating leases	$ 11	$ 12
Finance leases	24	12
Total lease liabilities	$ 35	$ 24

The following table summarizes PacifiCorp's lease costs for the years ended December 31 (in millions):

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Tri-State	)	Order No. 202-25-14
Generation and Transmission	)	
Association, Platte River Power	)	
Authority, Salt River Project,	)	
PacifiCorp, and Xcel Energy	)	

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-55:
Platte River Power Authority Coal Energy

Rawhide Energy Station

Commercial operation: 1984
Net capacity: 280 MW
Fuel type: coal
Operations: baseload

Operations

- Platte River's largest single source of system capacity at 280 net megawatts
- Used for baseload energy needs
- Provides approximately half of Platte River's annual delivered energy
- One of the highest-performing coal units in the U.S., averaging 97.28% equivalent availability and 85.08% capacity factor (as of May 31, 2020)
- Reliable fuel supply from Powder River Basin coal reserves in close proximity to plant
- Will be removed from Platte River's energy mix by Dec. 31, 2029

Financials

- Platte River's lowest operating cost generating resource
- Original debt retired in 2018
- Long-term rail and fuel contracts
- Fuel cost volatility mitigated through flexibility of existing contracts

Environmental

- Uses state-of-the-art air quality control technology to reduce emissions
- Maintains full compliance with strict environmental laws and regulations

- Healthy bison and waterfowl habitats at Rawhide demonstrate the ability for nature and industry to share space
- Water-efficient design utilizes reclaimed water from a domestic wastewater treatment plant
- No discharge of industrial wastewater from the facility due to beneficial reuse of all process water

Craig units 1 & 2 (Yampa Project)

Commercial operation: Unit 1—1980; Unit 2—1979
Net capacity: 151 MW
Fuel type: coal
Operations: baseload

Operations

- Platte River's ownership of Craig units 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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View all generation resources

For any accessibility requests, please call 970-226-4000.

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EN

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-25-14

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-56:
Xcel FERC Form 1

THIS FILING IS
Item 1: ☑ An Initial (Original) Submission OR ☐ Resubmission No.

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company) Public Service Company of Colorado	Year/Period of Report End of: 2024/ Q4

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q) is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities, Licensees, and Others Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

one million megawatt hours of total annual sales,

100 megawatt hours of annual sales for resale,

500 megawatt hours of annual power exchanges delivered, or

500 megawatt hours of annual wheeling for others (deliveries plus losses).

What and Where to Submit

Submit FERC Form Nos. 1 and 3-Q electronically through the eCollection portal at https://eCollection.ferc.gov, and according to the specifications in the Form 1 and 3-Q taxonomies.

The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:
Secretary
Federal Energy Regulatory Commission 888 First Street, NE
Washington, DC 20426

For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Schedules	Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of [COMPANY NAME] for the year ended on which we have reported separately under date of [DATE], we have also reviewed schedules [NAME OF SCHEDULES] of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases." The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. Further instructions are found on the Commission's website at https://www.ferc.gov/ferc-online/ferc-online/frequently-asked-questions-faqs-efilingferc-online.

Federal, State, and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from https://www.ferc.gov/general-information-0/electric-industry-forms.

When to Submit

FERC Forms 1 and 3-Q must be filed by the following schedule:

FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

Enter the month, day, and year for all dates. Use customary abbreviations. The "Date of Report" included in the header of each page is to be completed only for resubmissions (see VII. below).

Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

For any resubmissions, please explain the reason for the resubmission in a footnote to the data field.

Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

Schedule specific instructions are found in the applicable taxonomy and on the applicable blank rendered form.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and" firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

'Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

'Person' means an individual or a corporation;

'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; ......

"project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

'To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,168 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 168 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

"Sec. 304.

Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may by rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports shall be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309.

The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

GENERAL PENALTIES

The Commission may assess up to $1 million per day per violation of its rules and regulations. See FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

FERC FORM NO. 1
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION		
01 Exact Legal Name of Respondent Public Service Company of Colorado		02 Year/ Period of Report End of: 2024/ Q4
03 Previous Name and Date of Change (If name changed during year) /		
04 Address of Principal Office at End of Period (Street, City, State, Zip Code) 1800 Larimer Street, Suite 1100, Denver, CO 80202		
05 Name of Contact Person Melissa L. Ostrom		06 Title of Contact Person Senior Vice President, Controller
07 Address of Contact Person (Street, City, State, Zip Code) 414 Nicollet Mall, Minneapolis, MN 55401		
08 Telephone of Contact Person, Including Area Code (612) 330-5500	09 This Report is An Original / A Resubmission (1) ☑ An Original (2) ☐ A Resubmission	10 Date of Report (Mo, Da, Yr) 04/04/2025

Annual Corporate Officer Certification		
The undersigned officer certifies that: I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.		
01 Name Melissa L. Ostrom	03 Signature Melissa L. Ostrom	04 Date Signed (Mo, Da, Yr) 04/04/2025
02 Title Senior Vice President, Controller		
Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.		

Name of Respondent: Public Service Company of Colorado	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Name of Respondent: Public Service Company of Colorado	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Commission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

1. Summary of Significant Accounting Policies

Business and System of Accounts - PSCo is principally engaged in the regulated generation, purchase, transmission, distribution and sale of electricity and in the regulated purchase, transportation, distribution and sale of natural gas. PSCo is subject to regulation by the FERC and the Colorado Public Utility Commission (CPUC).

Basis of Accounting - The accompanying financial statements were prepared in accordance with the accounting requirements of the FERC as set forth in the Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than Generally Accepted Accounting Principles (GAAP). The following areas represent the significant differences between the Uniform System of Accounts and GAAP:

- Current maturities of long-term debt are included as long-term debt, while GAAP requires such maturities to be classified as current liabilities.
- Accumulated deferred income taxes are shown as long-term assets and liabilities at their gross amounts in the FERC presentation, in contrast to the GAAP presentation as net long-term assets and liabilities.
- Regulatory assets and liabilities are classified as current and noncurrent for GAAP presentation, while the FERC requires all regulatory assets and liabilities to be classified as noncurrent deferred debits and credits, respectively.
- Unrecognized tax benefits are recorded for temporary differences in accounts established for accumulated deferred income taxes in the FERC presentation, in contrast to the GAAP presentation as taxes accrued and noncurrent other liabilities.
- Removal costs for future removal obligations are classified as accumulated depreciation on the utility plant in the FERC presentation and as regulatory liabilities in the GAAP presentation.
- Certain commodity trading purchases and sales transactions are presented gross as expenses and revenues for the FERC presentation; however the net margin is reported as net sales for the GAAP presentation.
- Various expenses such as donations, lobbying, and other non-regulatory expenses are presented as other income deductions for the FERC presentation and reported as operating expenses for the GAAP presentation.
- Income tax expense is shown as a component of operating expense in the FERC presentation, in contrast to the GAAP presentation as a below-the-line deduction from operating income.
- Wholly-owned subsidiaries are reported using the equity method of accounting in the FERC presentation and are required to be consolidated for GAAP.
- Borrowings and repayments with subsidiary companies are investing activities in the FERC statement of cash flows; however, they are operating activities in the GAAP statement of cash flows.
- For certain capital projects where there is recovery of a return on construction work in progress (CWIP), certain amounts of allowance for funds used during construction (AFUDC) are not recognized in CWIP for GAAP, while for the FERC presentation, they are recorded in CWIP but the benefit is deferred as a liability and amortized over the life of the property as a reduction of costs.
- Deferred debt issuance costs are included as a deferred debit, while GAAP presentation includes them with long-term liabilities.
- Regulatory baselines have been specified for qualified and non-qualified pension cost, which are compared to costs recorded for GAAP; amounts above or below these baselines are deferred on a FERC basis.
- A 15-year fixed FERC regulatory amortization is being recorded to reduce the GAAP qualified pension prepaid asset included in rate base, while GAAP remeasures the prepaid amount each period based on actuarial measurement of net periodic pension cost and employer cash contributions to the trust.

If GAAP were followed, these financial statement line items would have values greater/(lesser) than those shown by the FERC presentation of:

(Millions of Dollars)		
Balance Sheet:		
Net utility plant	$	385
Current assets		142
Current liabilities		426
Other long-term assets		(1,050)
Long-term debt and other long-term liabilities		(949)
Statement of Income:		
Operating revenue	$	(77)
Operating expenses		(69)
Other income and deductions		37
Net interest charges		4

Subsequent Events - Management has evaluated the impact of events occurring after Dec. 31, 2024 up to Feb. 27, 2025, the date PSCo's GAAP financial statements were issued and has updated such evaluation for disclosure purposes through the date of the draft. These statements contain all necessary adjustments and disclosures resulting from that evaluation.

Use of Estimates — PSCo uses estimates based on the best information available to record transactions and balances resulting from business operations. Estimates are used for items such as plant depreciable lives or potential disallowances, asset retirement obligations (AROs), certain regulatory assets and liabilities, tax provisions, uncollectible amounts, environmental costs, unbilled revenues, jurisdictional fuel and energy cost allocations, actuarially determined benefit costs and wildfire contingencies. Recorded estimates are revised when better information becomes available or actual amounts can be determined. Revisions can affect operating results.

Regulatory Accounting — PSCo accounts for income and expense items in accordance with accounting guidance for regulated operations. Under this guidance:

- Certain costs, which would otherwise be charged to expense or other comprehensive income (OCI), are deferred as regulatory assets based on the expected ability to recover the costs in future rates.
- Certain credits, which would otherwise be reflected as income or OCI, are deferred as regulatory liabilities based on the expectation the amounts will be returned to customers in future rates, or because the amounts were collected in rates prior to the costs being incurred.

Estimates and assumptions for recovery of deferred costs and refund of deferred credits are based on specific ratemaking decisions, precedent or other available information. Regulatory assets and liabilities are amortized consistent with the treatment in the rate setting process.

If changes in the regulatory environment occur, PSCo may no longer be eligible to apply this accounting treatment and may be required to eliminate regulatory assets and liabilities. Such changes could have a material effect on PSCo's results of operations, financial condition and cash flows.

See Note 3 for further information.

Income Taxes — PSCo accounts for income taxes using the asset and liability method, which requires recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. Income taxes are deferred for all temporary differences between pretax financial and taxable income and between the book and tax bases of assets and liabilities utilizing rates that are scheduled to be in effect when the temporary differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in the period that includes the enactment date.

Utility rate regulation has resulted in the recognition of regulatory assets and liabilities related to income taxes. The effects of PSCo's tax rate changes are generally subject to a normalization method of accounting. Therefore, the revaluation of most of its net deferred taxes upon a tax rate reduction results in the establishment of a net regulatory liability, refundable to utility customers over the remaining life of the related assets. PSCo anticipates that a tax rate increase would predominantly result in the establishment of a regulatory asset, subject to an evaluation of whether future recovery is expected.

Tax credits are recorded when earned unless there is a requirement to defer the benefit and amortize over the book depreciable lives of related property. The requirement to defer and amortize these credits specifically applies to certain federal investment tax credits (ITCs), as determined by tax regulations and PSCo tax elections. For tax credits otherwise eligible to be recognized when earned, PSCo considers the impact of rate regulation to determine if these credits and related adjustments should be deferred as regulatory assets or liabilities.

Deferred tax assets are reduced by a valuation allowance if it is more likely than not that some portion or all of the deferred tax asset will not be realized. This evaluation includes consideration of whether tax credits are expected to be sold at a discount and impact the realization of amounts presented as deferred tax assets. Transferable tax credits are accounted for under ASC 740, *Income Taxes*, and valuation allowances and any adjustments for discounts incurred on sales transactions are recorded to deferred tax expense, typically recovered in regulatory mechanisms.

PSCo measures and discloses uncertain tax positions that it has taken or expects to take in its income tax returns. A tax position is recognized in the financial statements when it is more likely than not that the position will be sustained upon examination based on the technical merits of the position. Recognition of changes in uncertain tax positions are reflected as a component of income tax expense.

Interest and penalties are recorded separately to their respective line items in the income statement.

Xcel Energy Inc. and its subsidiaries, including PSCo file consolidated federal income tax returns as well as consolidated or separate state income tax returns. Federal income taxes paid by Xcel Energy Inc. are allocated to its subsidiaries based on separate company computations. A similar allocation is made for state income taxes paid by Xcel Energy Inc. in connection with consolidated state filings. Xcel Energy Inc. also allocates its own income tax benefits to its direct subsidiaries.

See Note 5 for further information.

Utility Plant and Depreciation in Regulated Operations — Utility plant is stated at original cost. The cost of plant includes direct labor and materials, contracted work, overhead costs and AFUDC. The cost of plant retired is charged to accumulated depreciation and amortization. Amounts recovered in rates for future removal costs are recorded as regulatory liabilities. Significant additions or improvements extending asset lives are capitalized, while repairs and maintenance costs and replacement of items determined to be less than a unit of property are charged to expense as incurred.

Utility plant is tested for impairment when it is determined that the carrying value of the assets may not be recoverable. A loss is recognized in the current period if it becomes probable that part of a cost of a plant under construction or recently completed plant will be disallowed for recovery from customers and a reasonable estimate of the disallowance can be made. For investments in utility plant that are abandoned and not expected to go into service, incurred costs and related deferred tax amounts are compared to the discounted estimated future rate recovery, and a loss is recognized, if necessary.

Depreciation expense is recorded using the straight-line method over the plant's commission approved useful life. Actuarial life studies are performed and submitted to the state and federal commissions for review. Upon acceptance by the various commissions, the resulting lives and net salvage rates are used to calculate depreciation. Plant removal costs are typically recognized at the amounts recovered in rates as authorized by the applicable regulator. Depreciation expense, expressed as a percentage of average depreciable property, was approximately 3.8% in 2024 and 3.6% in 2023.

AROs — PSCo records AROs as a liability in the period incurred (if fair value can be reasonably estimated), with the offsetting/associated costs capitalized as a long-lived asset. The liability is generally increased over time by applying the effective interest method of accretion and the capitalized costs are typically depreciated over the useful life of the long-lived asset. Changes resulting from revisions to timing or amounts of expected asset retirement cash flows are recognized as an increase or a decrease in the ARO.

See Note 8 for further information.

Benefit Plans and Other Postretirement Benefits — PSCo maintains pension and postretirement benefit plans for eligible employees. Recognizing the cost of providing benefits and measuring the projected benefit obligation of these plans requires management to make various assumptions and estimates.

Certain unrecognized actuarial gains and losses and unrecognized prior service costs or credits are deferred as regulatory assets and liabilities, rather than recorded as other comprehensive income, based on regulatory recovery mechanisms.

See Note 7 for further information.

Environmental Costs — Environmental costs are recorded when it is probable PSCo is liable for remediation costs and the amount can be reasonably estimated. Costs are deferred as a regulatory asset if it is probable that the costs will be recovered from customers in future rates. Otherwise, the costs are expensed. For certain environmental costs related to facilities currently in use, such as for emission-control equipment, the cost is capitalized and depreciated over the life of the plant.

Estimated remediation costs are regularly adjusted as estimates are revised and remediation is performed. If other participating potentially responsible parties exist and acknowledge their potential involvement with a site, costs are estimated and recorded only for PSCo's expected share of the cost.

Future costs of restoring sites are treated as a capitalized cost of plant retirement.

See Note 8 for further information.

Revenue from Contracts with Customers — Performance obligations related to the sale of energy are satisfied as energy is delivered to customers. PSCo recognizes revenue that corresponds to the price of the energy delivered to the customer. The measurement of energy sales to customers is generally based on the reading of their meters, which occurs systematically throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated, and the corresponding unbilled revenue is recognized.

A separate financing component of collections from customers is not recognized as contract terms are short-term in nature. Revenues are net of any excise or sales taxes or fees.

PSCo recognizes physical sales to customers (native load and wholesale) on a gross basis in electric revenues and cost of sales. PSCo participates in SPP WEIS. Revenues for short-term physical wholesale sales of excess energy transacted through the imbalance market are recorded on a gross basis. Other revenues and charges settled/facilitated through SPP WEIS are recorded on a net basis in cost of sales.

Cash and Cash Equivalents — PSCo considers investments in instruments with a remaining maturity of three months or less at the time of purchase to be cash equivalents.

Accounts Receivable and Allowance for Bad Debts — Accounts receivable are stated at the actual billed amount net of an allowance for bad debts. PSCo establishes an allowance for uncollectible receivables based on a policy that reflects its expected exposure to the credit risk of customers. As of Dec. 31, 2024 and 2023, the allowance for bad debts was $50 million and $56 million, respectively.

Inventory — Inventory is recorded at the lower of average cost or net realizable value.

Fair Value Measurements — PSCo presents cash equivalents, interest rate derivatives, commodity derivatives and pension and postretirement plan assets at estimated fair values in its financial statements.

For interest rate derivatives, quoted prices based primarily on observable market interest rate curves are used to estimate fair value. For commodity derivatives, the most observable inputs available are generally used to determine the fair value of each contract. In the absence of a quoted price, quoted prices for similar contracts or internally prepared valuation models may be used to determine fair value.

For the pension and postretirement plan assets, published trading data and pricing models, generally using the most observable inputs available, are utilized to determine fair value for each security.

See Notes 6 and 7 for further information.

Derivative Instruments — PSCo uses derivative instruments in connection with its commodity trading activities, and to manage risk associated with changes in interest rates and utility commodity prices, including forward contracts, futures, swaps and options. Derivatives not qualifying for the normal purchases and normal sales exception are recorded on the balance sheets at fair value as derivative instruments. Classification of changes in fair value for those derivative instruments is dependent on the designation of a qualifying hedging relationship.

Changes in fair value of derivative instruments not designated in a qualifying hedging relationship are reflected in current earnings or as a regulatory asset or liability. Classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms.

Gains or losses on commodity trading transactions are recorded as a component of electric operating revenues.

Normal Purchases and Normal Sales — PSCo enters into contracts for purchases and sales of commodities for use and sale in its operations. At inception, contracts are evaluated to determine whether they contain a derivative, and if so, whether they may be exempted from derivative accounting if designated as normal purchases or normal sales.

Commodity Trading Operations — Commodity trading activities are not associated with energy produced from PSCo's generation assets or energy and capacity purchased to serve native load. Commodity trading contracts are recorded at fair market value and commodity trading results include the impact of all margin-sharing mechanisms.

See Note 6 for further information.

AFUDC — AFUDC represents the cost of capital used to finance utility construction activity and is computed by applying a composite financing rate to qualified CWIP. The amount of AFUDC capitalized as a utility construction cost is credited to other nonoperating income (for equity capital) and interest charges (for debt capital). AFUDC amounts capitalized are included in PSCo's rate base.

Alternative Revenue — Certain rate rider mechanisms (including decoupling and demand side management (DSM) programs) qualify as alternative revenue programs. These mechanisms arise from instances in which the regulator authorizes a future surcharge in response to past activities or completed events. When certain criteria are met, including expected collection within 24 months, revenue is recognized, which may include incentives and return on rate base items.

Billing amounts are revised periodically for differences between total amount collected and revenue earned, which may increase or decrease the level of revenue collected from customers. Alternative revenues arising from these programs are presented on a gross basis and disclosed separately from revenue from contracts with customers.

Conservation Programs — The costs incurred for DSM programs are deferred if it is probable future revenue will be provided to permit recovery of the incurred cost. Revenues recognized for incentive programs designed for recovery of DSM program costs and/or conservation performance incentives are limited to amounts expected to be collected within 24 months from the year in which they are earned.

PSCo's DSM program costs are recovered through rider mechanisms. Regulatory assets are recognized to reflect the amount of costs or earned incentives that have not yet been collected from customers.

Emission Allowances — Emissions allowances are recorded at cost, including broker commission fees. The inventory accounting model is utilized for all emissions allowances and any sales of these allowances are included in electric revenues.

Renewable Energy Credits (RECs) — Cost of RECs that are utilized for compliance is recorded as electric fuel and purchased power expense. An inventory accounting model is used to account for RECs.

Sales of RECs are recorded in electric revenues on a gross basis. Cost of these RECs and amounts credited to customers under margin-sharing mechanisms are recorded in electric fuel and purchased power expense.

2. Joint Ownership of Generation, Transmission and Gas Facilities

Jointly owned assets as of Dec. 31, 2024:

(Millions of Dollars, Except Percent Owned)	Plant in Service	Accumulated Depreciation	Percent Owned
Electric generation:			
Hayden Unit 1	$ 158	$ 117	76 %
Hayden Unit 2	152	93	37
Hayden common facilities	45	33	53
Craig Units 1 and 2	82	58	10
Craig common facilities	40	27	7
Comanche Unit 3	933	212	67
Comanche common facilities	29	5	77
Electric transmission:			
Transmission and other facilities	190	75	Various
Gas transmission:			
Rifle, CO to Avon, CO	28	10	60
Gas transmission compressor	8	3	50
Total [(a)]	$ 1,665	$ 633	

(a) Projects additionally include $28 million in CWIP

PSCo's share of operating expenses and construction expenditures is included in the applicable utility accounts. Respective owners are responsible for providing their own financing.

3. Regulatory Assets and Liabilities

Regulatory assets and liabilities are created for amounts that regulators may allow to be collected or may require to be paid back to customers in future electric and natural gas rates. PSCo would be required to recognize the write-off of regulatory assets and liabilities in net income or OCI if changes in the utility industry no longer allow for the application of regulatory accounting guidance under GAAP.

Components of regulatory assets:

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Tri-State	)	Order No. 202-25-14
Generation and Transmission	)	
Association, Platte River Power	)	
Authority, Salt River Project,	)	
PacifiCorp, and Xcel Energy	)	

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-57:
2018 SIP Element Adopted

Table 6 - 2 BART Determinations for Colorado Sources					
Emission Unit	**Assumed ** NOx Control Type**	**NOx Emission Limit**	**Assumed ** SO_2 Control Type**	**SO_2 Emission Limit**	**Assumed ** Particulate Control and Emission Limit**
Cemex - Lyons Kiln	Selective Non-Catalytic Reduction System	255.3 lbs/hr (30-day rolling average) 901.0 tons/yr (12-month rolling average)	None	25.3 lbs/hr (12-month rolling average) 95.0 tons/yr (12-month rolling average)	Fabric Filter Baghouse * 0.275 lb/ton of dry feed 20% opacity
Cemex - Lyons Dryer	None	13.9 tons/yr	None	36.7 tons/yr	Fabric Filter Baghouse* 22.8 tons/yr 10% opacity
CENC Unit 4	Low NOx Burners with Separated Over-Fire Air	0.37 lb/MMBtu (30-day rolling average) Or 0.26 lb/MMBtu Combined Average for Units 4 & 5 (30-day rolling average)	None	1.0 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.07 lb/MMBtu
CENC Unit 5	Low NOx Burners with Separated Over-Fire Air, and Selective Non-Catalytic Reduction System	0.19 lb/MMBtu (30-day rolling average) Or 0.26 lb/MMBtu Combined Average for Units 4 & 5 (30-day rolling average)	None	1.0 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.07 lb/MMBtu
Comanche Unit 1	Low NOx Burners*	0.20 lb/MMBtu (30-day rolling average) 0.15 lb/MMBtu (combined annual average for units 1 & 2)	Lime Spray Dryer*	0.12 lb/MMBtu (30-day rolling average) 0.10 lb/MMBtu (combined annual average for units 1 & 2)	Fabric Filter Baghouse* 0.03 lb/MMBtu

Comanche Unit 2	Low NOx Burners*	0.20 lb/MMBtu (30-day rolling average) 0.15 lb/MMBtu (combined annual average for units 1 & 2)	Lime Spray Dryer*	0.12 lb/MMBtu (30-day rolling average) 0.10 lb/MMBtu (combined annual average for units 1 & 2)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Craig Unit 1	Selective Catalytic Reduction System	***	Wet Limestone scrubber*	0.11 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Craig Unit 2	Selective Catalytic Reduction System	0.08 lb/MMBtu (30-day rolling average)	Wet Limestone scrubber*	0.11 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Hayden Unit 1	Selective Catalytic Reduction System	0.08 lb/MMBtu (30-day rolling average)	Lime Spray Dryer*	0.13 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Hayden Unit 2	Selective Catalytic Reduction System	0.07 lb/MMBtu (30-day rolling average)	Lime Spray Dryer*	0.13 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Martin Drake Unit 5	Ultra Low-NOx Burners (including Over-Fire Air)	0.31 lb/MMBtu (30-day rolling average)	Dry Sorbent Injection	0.26 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Martin Drake Unit 6	Ultra Low-NOx Burners (including Over-Fire Air)	0.31 lb/MMBtu (30-day rolling average)	Lime Spray Dryer or Equivalent Control Technology	0.13 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Martin Drake Unit 7	Ultra Low-NOx Burners (including Over-Fire Air)	0.29 lb/MMBtu (30-day rolling average)	Lime Spray Dryer or Equivalent Control Technology	0.13 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu

* Controls are already operating

** Based on the state's BART analysis, the "assumed" technology reflects the control option found to render the BART emission limit achievable. The "assumed" technology listed in the above table is not a requirement.

*** Craig Unit 1 will either close on or before December 31, 2025 ***or*** cease burning coal no later than August 31, 2021 with the option to convert the unit to natural-gas firing by August 31, 2023. In the case of a conversion to natural-gas firing, a 30-day rolling average NOx emission limit of no more than 0.07 lb/MMBtu will be effective after August 31, 2021. Effective January 1, 2017 (first compliance date January 31, 2017), Craig Unit 1 will be subject to a NOx emission limit of 0.28 lb/MMBtu 30-day rolling average until closing or converting to natural gas. Additionally, an annual NOx limit of 4,065 tons per year will be effective December 31, 2019 on a calendar year basis beginning in 2020 for Craig Unit 1. The Division shall be notified in writing by the owner-operator no later than February 28, 2021 whether Craig Unit 1 will close or convert to gas.

6.4.3.4 BART Determination for Tri-State Generation and Transmission Association's Craig Facility

Craig Units 1 and 2 are BART-eligible, being fossil-fuel steam electric plants of more than 250 MMBtu/hr heat input with the potential to emit 250 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}), and having commenced operation in the 15-year period prior to August 7, 1977. These boilers also cause or contribute to visibility impairment at a federal Class I area at or above a 0.5 deciview change. Tri-State submitted a BART Analysis to the Division on July 31, 2006 with revisions, updates, and/or comments submitted on October 25, 2007, December 31, 2009, May 14, 2010, June 4, 2010 and July 30, 2010.

SO2 BART Determination for Craig - Units 1 and 2

Wet FGD Upgrades – As discussed in EPA's BART Guidelines, electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent do not need to be evaluated for potential removal of controls and replacement with new controls. Therefore, the following wet scrubber upgrades were considered for Craig Units 1 and 2, if technically feasible.

- *Elimination of bypass reheat*: The FGD system bypass was redesigned to eliminate bypass of the FGD system except for boiler safety situations in 2003-2004.
- *Installation of liquid distribution rings:* Tri-State determined that installation of perforated trays, described below, accomplished the same objective.
- *Installation of perforated trays:* Upgrades during 2003-2004 included installation of a perforated plate tray in each scrubber module.
- *Use of organic acid additives:* Organic acid additives were considered but not selected for the following reasons:
    1. Dibasic Acid (DBA) has not been tested at the very low inlet SO_2 concentrations seen at Craig Units 1 and 2.
    2. DBA could cause changes in sulfite oxidation with impacts on SO_2 removal and solids settling and dewatering characteristics.
    3. Installation of the perforated plate tray accomplished the same objective of increased SO_2 removal.
- *Improve or upgrade scrubber auxiliary equipment:* 2003-2004 upgrades included installation of the following upgrades on limestone processing and scrubber modules on Craig 1 and 2:
    1. Two vertical ball mills were installed for additional limestone processing capability for increased SO_2 removal. The two grinding circuit trains were redesigned to position the existing horizontal ball mills and the vertical ball mills in series to accommodate the increased quantity of limestone required for increased removal rates. The two mills in series also were designed to maintain the fine particle size (95% <325 mesh or 44 microns) required for high SO_2 removal rates.

2. Forced oxidation within the SO_2 removal system was thought necessary to accommodate increased removal rates and maintain the dewatering characteristics of the limestone slurry. Operation, performance, and maintenance of the gypsum dewatering equipment are more reliable with consistent slurry oxidation.
3. A ventilation system was installed for each reaction tank.
4. A new mist eliminator wash system was installed due to the increased gas flow through the absorbers since flue gas bypass was eliminated, which increased demand on the mist eliminator system. A complete redesign and replacement of the mist eliminator system including new pads and wash system improved the reliability of the individual modules by minimizing down time for washing deposits out of the pads.
5. Tri-State installed new module outlet isolation damper blades. The new blades, made of a corrosion-resistant nickel alloy, allow for safer entry into the non-operating module for maintenance activities.
6. Various dewatering upgrades were completed. Dewatering the gypsum slurry waste is done to minimize the water content in waste solids prior to placements of the solids in reclamation areas at the Trapper Mine. The gypsum solids are mixed or layered with ash and used for fill during mine reclamation at Trapper Mine. The installed system was designed for the increased capacity required for increased SO_2 removal. New hydrocyclones and vacuum drums were installed as well as a new conveyor and stack out system for solid waste disposal.
7. Instrumentation and controls were modified to support all of the new equipment.

- *Redesign spray header or nozzle configuration:* The slurry spray distribution was modified during 2003-2004. The modified slurry spray distribution system improved slurry spray characteristics and was designed to minimize pluggage in the piping.

Therefore, there are no technically feasible upgrade options for Craig Station Units 1 and 2. However, the state evaluated the option of tightening the emission limit for Craig Units 1 and 2 through the five-factor analysis and determined that a more stringent 30-day rolling SO_2 limit of 0.11 lbs/MMBtu represents an appropriate level of emissions control for this wet FGD control technology based on current emissions and operations. The tighter emission limits are achievable without additional capital investment. An SO2 limit lower than 0.11 lbs/MMBtu would likely require additional capital expenditure and is not reasonable for the small incremental visibility improvement of 0.02 deciview.

The projected visibility improvements attributed to the alternatives are as follows:

SO2 Control Method	Craig – Unit 1		Craig – Unit 2	
	SO2 Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	SO2 Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.17		0.16	
Wet FGD	0.11	0.03	0.11	0.03
Wet FGD	0.07	0.05	0.07	0.05

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that SO2 BART is the following SO2 emission rates:

Craig Unit 1: 0.11 lb/MMBtu (30-day rolling average)

Craig Unit 2: 0.11 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the operation of existing lime spray dryers (LSD). The 30-day rolling SO2 limit of 0.11 lbs/MMBtu represents an appropriate level of emissions control associated with semi-dry FGD control technology.

Particulate Matter BART Determination for Craig - Units 1 and 2

The Division has determined that the existing Unit 1 and 2 emission limit of 0.03 lb/MMBtu (PM/PM_{10}) represents the most stringent control option. The units are exceeding a PM control efficiency of 95%, and the control technology and emission limits are BART for $PM/PM_{10.}$ The state assumes that the BART emission limit can be achieved through the operation of the existing pulse jet fabric filter baghouses.

NOx BART Determination for Craig - Units 1 and 2

Potential modifications to the ULNBs, neural network systems, selective non-catalytic reduction (SNCR), and selective catalytic reduction (SCR) were determined to be technically feasible for reducing NOx emissions at Craig Units 1 and 2.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Craig Unit 1 - NO_x Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
SNCR	779	$3,797,000	$4,877
SCR	4,048	$25,036,709	$6,184

Craig Unit 2 - NOx Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
SNCR	806	$3,797,000	$4,712
SCR	3,975	$25,036,709	$6,298

The energy and non-air quality impacts of SNCR are increased power needs, potential for ammonia slip, potential for visible emissions, and hazardous materials storage and handling.

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

NOx Control Method	Craig – Unit 1		Craig – Unit 2	
	NOx Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	NOx Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (3-yr)	0.35		0.35	
SNCR	0.24	0.31	0.23	0.31
SCR	0.07	1.01	0.08	0.94

While potential modifications to the ULNB burners and a neural network system were also found to be technically feasible, these options did not provide the same level of reductions as SNCR or SCR, which are included within the ultimate BART determination for Units 1 and 2. Therefore, these options were not further considered in the technical analysis.

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that NOx BART is the following NOx emission rates:

Craig Unit 1: 0.070 lb/MMBtu (30-day rolling average)

Craig Unit 2: 0.080 lb/MMBtu (30-day rolling average)

The 0.08 lb/MMbtu limit for Unit 2 was based upon evidence before the AQCC in 2010, and took into consideration both cost and feasibility. Significant progress towards installation of SCR at Unit 2 has been made, and the vendor has guaranteed performance at the 0.08 lb/MMBtu 30-day rolling average NOx limit. Both vendor performance and equipment performance can improve over time, and the Division has determined, and Tri-State has agreed, that Tri-State can achieve a 0.07 lb/MMBtu NOx limit at Unit 1. The state assumes that the BART emission limits can be achieved through the operation of SCR. For SCR at Units 1 and 2, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls above the guidance criteria presented earlier in Chapter 6. The criteria guide the state's general approach to these policy considerations, but are not binding. Therefore, the state deviates from the guidance criteria in this case due to the fact that Tri-State has agreed to achieve the proposed emission rates at Craig Units 1 and 2 and the notable visibility improvements..

- Unit 1: $6,184 per ton NOx removed; 1.01 deciview of improvement
- Unit 2: $6,298 per ton NOx removed; 0.94 deciview of improvement

To the extent practicable, any technological application Tri-State utilizes to achieve these BART emission limits shall be installed, maintained, and operated in a manner consistent with good air pollution control practices for minimizing emissions. Once EPA approves this revision to the Regional Haze SIP, Tri-State will be required to meet the 0.07 lb/MMBtu NOx emission limit by August 31, 2021. Once the revised emission limit is approved, Tri-State will begin the design and development of bid documents, engage in a process to review bids and select a contractor for the multi-year construction project. Based on Tri-State's experience at Unit 2 (where construction and installation of SCR is already underway), and taking into consideration such factors as the weather in Craig, Colorado, the coordination necessary between the various owners of Unit 1, electric utilities and regional entities responsible for the bulk electric system, and compliance deadlines for other similar types of facilities in Colorado, Arizona and Wyoming, the Division has determined that the compliance deadline of August 31, 2021 is as expeditiously as practicable as SCR can be installed at Unit 1. This BART determination is the result of an agreement between Tri-State, WildEarth Guardians, the National Parks Conservation Association, EPA, and the state to resolve an appeal of EPA's approval of Craig Station –related elements of Colorado's Regional Haze Plan. This BART determination is consistent with the information provided by the FLMs and is supported by the associated visibility improvement information as well as the SCR cost information provided in the SIP materials and otherwise reflected in the 2014 hearing record.

In 2016, based on new information provided from an agreement amongst Tri-State, WildEarth Guardians, the National Parks Conservation Association, EPA, and the state, the state conducted a BART reassessment for Craig Unit 1. This reassessment evaluates the additional scenarios:

Scenario 1 (Close by December 31, 2025): The first table below assumes an amortization period of four years and four months of operation from the projected compliance date to the date of retirement (December 31, 2025) and that control technology could be installed by August 31, 2021, consistent with the 2014 BART determination. In the second table below, an assumed amortization period of eight years of operation[1] is used since a projected compliance date could occur earlier depending on the alternative selected. Both of these assumed amortization periods change the remaining useful life for the alternatives as Craig Unit 1 will no longer remain in service for the 20-year amortization period used in the 2014 BART determination, depending on the alternative selected[2]. Both of these reduced timeframes change the cost effectiveness for the alternatives as follows:

[1] Operation period begins calendar year 2018 (December 31, 2017).
[2] EPA finalized revisions of the Air Pollution Cost Control Manual (Chapters 1 and 2) in May 2016; these revisions change the amortization period for SCR from 20 years to 30 years. The amortization period for SNCR remains 20 years.

Craig Unit 1 - NO_x Cost Comparisons (assuming four years, four months of operation)			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
SNCR	779	$6,172,522	$7,928
SCR	4,048	$64,106,699	$15,835

Craig Unit 1 - NO_x Cost Comparisons (assuming eight years of operation)			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
SNCR	779	$4,755,842	$6,109
SCR	4,048	$41,476,535	$10,245

Based on this assessment, regardless of the amortization period used, both SNCR and SCR are not cost effective when the remaining useful life is shortened, and when considering the remaining BART factors as discussed in Appendix C. For Craig Unit 1, a NOx emission limit of 0.07 lb/MMBtu (2014 BART determination) is BART under a 20 or 30 year remaining useful life.

or;

Scenario 2: A cease coal burning date of August 31, 2021 with the option to convert the unit to natural-gas firing by August 31, 2023. In the case of a conversion to natural-gas firing, a 30-day rolling average NOx emission limit of no more than 0.07 lb/MMBtu applies after August 31, 2021. This scenario (without the inclusions below) is equivalent to the 2014 BART determination.

Both of these scenarios include a 30-day rolling average NOx emission limit of 0.28 lb/MMBtu that will commence on January 1, 2017 (first compliance date January 31, 2017) and be effective until either closure or conversion to natural gas. Additionally, an annual NOx limit of 4,065 tons per year will be effective December 31, 2019 on a calendar year basis beginning in 2020 for Craig Unit 1.

The scenario options under this BART reassessment are the result of an agreement. This reassessment relies on the 2014 BART determination for Craig Unit 1 and supplements that determination to reflect the terms of the agreement. This agreement achieves greater air quality benefits than the 2011 Regional Haze SIP. Both of these scenarios achieve greater NOx reductions and other environmental co-benefits compared to the 2014 BART determination. Consistent with the agreement, Craig Unit 1 will either close on or before December 31, 2025 ***or*** cease burning coal by August 31, 2021 with the option to convert the unit to natural-gas firing by August 31, 2023. In the case of a conversion to natural-gas firing, a 30-day rolling average NOx emission limit of no more than 0.07 lb/MMBtu will apply after August 31, 2021. Effective January 1, 2017 (first compliance date January 31, 2017), Craig Unit 1 will be subject to a NOx emission limit of 0.28 lb/MMBtu 30-day rolling average until closure or conversion to natural gas. Additionally, an annual NOx limit of 4,065 tons per year will be effective on December 31, 2019 on a calendar year basis beginning in 2020 for Craig Unit 1.

A complete analysis that supports the BART determination for Craig Station Units 1 and 2 and the BART reassessment for Unit 1, including substantial cost information for NOx controls, can be found in Appendix C.

Chapter 8 Reasonable Progress

8.5.2 Point Source RP Determinations

The following summarizes the RP control determinations that will apply to each source.

Table 8-2 RP Control Determinations for Colorado Sources

Emission Unit	Assumed** NOx Control Type	NOx Emission Limit	Assumed** SO_2 Control Type	SO_2 Emission Limit	Assumed** Particulate Control and Emission Limit
Rawhide Unit 101	Enhanced Combustion Control*	0.145 lb/MMBtu (30-day rolling average)	Lime Spray Dryer*	0.11 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
CENC Unit 3	No Control	246 tons per year (12-month rolling total)	No Control	1.2 lbs/MMBtu	Fabric Filter Baghouse* 0.07 lb/MMBtu
Nixon Unit 1	Ultra-low NOx burners with Over-Fire Air	0.21 lb/MMBtu (30-day rolling average)	Lime Spray Dryer	0.11 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Clark Units 1 &2	Shutdown 12/31/2013	0	Shutdown 12/31/2013	0	Shutdown 12/31/2013
Holcim - Florence Kiln	SNCR	2.73 lbs/ton clinker (30-day rolling average) 2,086.8 tons/year	Wet Lime Scrubber*	1.30 lbs/ton clinker (30-day rolling average) 721.4 tons/year	Fabric Filter Baghouse* 246.3 tons/year
Nucla	No Control	0.5 lb/MMBtu (30-day rolling average)***	Limestone Injection*	0.4 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Craig Unit 3	SNCR	0.28 lb/MMBtu (30-day rolling average)	Lime Spray Dryer*	0.15 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 0.013 lb/MMBtu filterable PM 0.012 lb/MMBtu PM10
Cameo	Shutdown 12/31/2011	0	Shutdown 12/31/2011	0	Shutdown 12/31/2011

* Controls are already operating

** Based on the state's RP analysis, the "assumed" technology reflects the control option found to render the RP emission limit achievable. The "assumed" technology listed in the above table is not a requirement.

*** Nucla Station will close on or before December 31, 2022. Additionally, an annual NOx limit of 952 tons per year will be effective on January 1, 2020 beginning in 2020 on a calendar year basis for Nucla Station.

8.5.2.6 RP Determination for Tri-State Generation and Transmission Association's Nucla Facility

The Tri-State Nucla Station is located in Montrose County about 3 miles southeast of the town of Nucla, Colorado. The Nucla Station consists of one coal fired steam driven electric generating unit (Unit 4), with a rated electric generating capacity of 110 MW (gross), which was placed into service in 1987. Nucla Unit 4 is considered by the Division to be eligible for the purposes of Reasonable Progress, being an industrial boiler with the potential to emit 40 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}) at a facility with a Q/d impact greater than 20. Tri-State Generation and Transmission Association (Tri-State) provided information relevant to RP to the Division on December 31, 2009, May 14, 2010, June 4, 2010 and July 30, 2010.

SO2 RP Determination for Nucla – Unit 4

Limestone injection improvements, a spray dry absorber (SDA) system (or dry FGD), limestone injection improvements with a SDA, hydrated ash reinjection (HAR), and HAR with limestone injection improvements were determined to be technically feasible for reducing SO2 emissions from Nucla Unit 4. Study-level information for HAR systems at Nucla or any other EGU in the western United States were not available for use in evaluating costs. Since the option to install a dry FGD alone (even without improving limestone injection) provides a better estimated control efficiency than a HAR system plus limestone injection improvements, the HAR system was not considered further in this analysis.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Nucla Unit 4 - SO2 Cost Comparison			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
Limestone Injection Improvements	526	$914,290	$4,161
Spray Dry Absorber (dry FGD)	1,162	$7,604,627	$6,547
Limestone Injection Improvements + dry FGD	1,254	$9,793,222	$7,808

A dry FGD system, or limestone injection improvements plus dry FGD system, were eliminated from consideration by the state as unreasonable during this planning period due to: 1) the excessive costs, 2) that they would require replacement of an existing system and installation of a completely new system (with attendant new capital costs and facility space considerations), and 3) the lack of modeled visibility affects associated with these particular SO2 reductions.

There is no energy and non-air quality impacts associated with limestone injection improvements. For dry FGD, the energy and non-air quality impacts include less mercury removal compared to unscrubbed units and significant water usage.

There are no remaining useful life issues for alternatives as the source will remain in service for the 20-year amortization period.

Due to time and domain constraints, projected visibility improvements were not modeled by the state for this analysis.

Nucla already has a system in place to inject limestone into the boiler as required by current state and federal air permits. This system achieves an approximate 70% SO2 emissions reduction capture efficiency at a permitted emission rate of 0.4 lbs/MMBtu limit. Increased SO2 capture efficiency (85%) with the existing limestone injection as an effective system upgrade, by use of more limestone (termed "limestone injection improvements") was evaluated and determined to not be feasible under certain operating conditions. The system cannot be 'run harder' with more limestone to achieve a more stringent SO2 emission limit; the system would have to be reconstructed or redesigned with attendant issues, or possibly require a new or different SO2 system, to meet an 85% capture efficiency.

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that the existing permitted SO2 emission rate for Unit 4 satisfies RP:

Nucla Unit 4: 0.4 lb/MMBtu (30-day rolling average)

The state assumes that the emission limit can be achieved through the operation of the existing limestone injection system.

PM10 RP Determination for Nucla – Unit 4

The state has determined that the existing regulatory emissions limit of 0.03 lb/MMBtu represents the most stringent control option. The unit is exceeding a PM control efficiency of 95%, and the emission limit is RP for PM/PM_{10}. The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouse.

NOx RP Determination for Nucla – Unit 4

Selective non-catalytic reduction (SNCR) was determined to be technically feasible for reducing NOx emissions at Nucla Unit 4. SCR is not technically feasible on a circulating fluidized bed coal-fired boiler, and is otherwise not cost-effective, as discussed in Appendix D. With respect to SNCR, however, there is substantial uncertainty surrounding the potential control efficiency achievable by a full-scale SNCR system at a CFB boiler burning western United States coal. The state and Tri-State's estimates vary between 10 – 40% NOx reduction potential, which correlates to between $3,000 - $17,000 per ton NOx reduced and may result in between 100 to 400 tons NOx reduced per year.

The energy and non-air quality impacts of SNCR are increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling.

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

Due to time and domain constraints, projected visibility improvements were not modeled by the state for this analysis. There are several qualitative reasons that NOx controls may be warranted at Nucla. First, NOx control alternatives may result in between 100 – 400 tons of NOx reduced annually. Second, Nucla is within 100 kilometers in proximity to three Class I areas, depicted in the figure above, and within approximately 115 kilometers to five Class I areas, including Utah's Canyonlands and Arches National Parks. Third, Nucla has a limited, small-scale SNCR system for emissions trimming purposes installed.

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the State has determined that NOx RP for Nucla Unit 4 is no control at the following NOx emission rate:

Nucla Unit 4: 0.5 lb/MMBtu (30-day rolling average)

Additional Analyses of SO2 and NOx Controls for Nucla

As state-only requirements of this Reasonable Progress determination, the Commission requires, and Tri-State agrees, that Tri-State conduct a comprehensive four factor analysis of all SO2 and NOx control options for Nucla using site-specific studies and cost information and provide to the state a draft analysis by July 1, 2012. A protocol for the four-factor analysis and studies will be approved by the Division in advance. The analysis will include enhancements or upgrades to the existing limestone injection system for increased SO2 reduction performance, other relevant SO2 control technologies such as lime spray dryers and flue gas desulfurization, and all NOx control options. A final analysis that addresses the state's comments shall be submitted to the state by January 1, 2013. By January 1, 2013, Tri-State shall also conduct appropriate cost analyses, study and, if deemed necessary by the state and the source, testing, as approved by the Division, to inform what performance would be achieved by a full-scale SNCR system at Nucla to determine potential circulating fluidized bed (CFB) boiler-specific NOx control efficiencies. By January 1, 2013, Tri-State shall conduct CALPUFF modeling in compliance with the Division's approved BART-modeling protocol to determine potential visibility impacts the different SO2 and NOx control scenarios for Nucla. Finally, Tri-State shall propose to the state any preferred SO2 and NOx emission control strategies for Nucla by January 1, 2013. On December 26, 2012, Tri-State submitted an updated four-factor analysis and visibility modeling to the Division, with the conclusion that limestone for SO2 control and existing SNCR for NOx reduction remained the preferred strategy.

Requirements for Nucla Station

On December 31, 2012, EPA approved Colorado's Regional Haze SIP, including Colorado's Reasonable Progress determination for Nucla Unit 4 (0.5 lb/MMBtu (30-day rolling average)). In 2016, based on new information provided from an agreement amongst Tri-State, WildEarth Guardians, the National Parks Conservation Association, EPA, and the state, the state conducted a Reasonable Progress review of Nucla. This review adds a requirement of a closure date on or before December 31, 2022 for Nucla Station. Additionally, an annual NO_x limit of 952 tons per year will be effective January 1, 2020 on a calendar year basis beginning in 2020.

These requirements are the result of an agreement. The 2022 closure achieves further NOx reductions and other environmental co-benefits than the 2011 RP determination. Consistent with the agreement and in lieu of being subject to stringent requirements as part of the long term strategy for the second implementation period of Regional Haze, Nucla Station will close by December 31, 2022.

Additionally, an annual NOx limit of 952 tons per year will be effective on January 1, 2020 on a calendar year basis beginning in 2020. Nucla Unit 4 will still comply with the 2011 RP determination of 0.5 lb/MMBtu (30-day rolling average) until closure. A complete analysis that supports the RP determination and review for the Nucla facility can be found in Appendix D.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-25-14

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-58:
Lisa Tiffin 2020 ERP Direct Testimony

**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 LISA K. TIFFIN
ON BEHALF OF
TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.**

December 1, 2020

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ATTACHMENTS

Attachment LKT-1	Curriculum Vitae of Lisa K Tiffin

GLOSSARY

Term	**Meaning**
ARIMA	Auto-Regressive Integrated Moving Average
AQCC	Colorado Air Quality Control Commission
BA	Balancing Authority
BE	Beneficial Electrification
BEA	U.S. Department of Commerce Bureau of Economic Analysis
CAISO	California Independent System Operator
CDPHE	Colorado Department of Public Health and Environment
CEP	Clean Energy Plan
EIA	Energy Information Administration
ERP	Electric Resource Plan
GHG	Greenhouse Gas
PNM	Public Service Company of New Mexico
RAP	Resource Acquisition Period
RES	Renewable Energy Standard
RPS	Renewable Portfolio Standard
RTO	Regional Transmission Organization
RUS	Rural Utilities Service
SAE	Statistically Adjusted End-Use
SIP	State Implementation Plan
SPP	Southwest Power Pool
WEIM	Western Energy Imbalance Market
WEIS	Western Energy Imbalance Service
W&P	Woods & Poole Economics, Inc.
WAPA	Western Area Power Administration

A: While the Commission need not consider New Mexico's RPS when evaluating Tri-State's Colorado ERP, Tri-State operates an integrated, interconnected, interstate generation and transmission system that must meet the legislative and regulatory requirements of all of the states in which it is located. Tri-State must ensure that its system and associated resources comply with Colorado's and New Mexico's relevant laws and regulations.

Q: IS TRI-STATE'S 2020 ERP CONSISTENT WITH ALL STATE AND FEDERAL LAWS RELATED TO RENEWABLE STANDARDS?

A: Yes. As described in Volume I, "Base Case and Alternative Scenario Comparison" and in Volume II Attachment 6-2 of the ERP, Tri-State is exceeding the requirements of both the Colorado RES and the New Mexico RPS.

XIII. COSTS AND BENEFITS OF EARLY RETIREMENTS

Q: HOW WERE THE ANNOUNCED EARLY RETIREMENT DATES OF CRAIG UNIT 1, CRAIG UNIT 2 AND CRAIG UNIT 3 DEVELOPED?

A: The owners (Yampa Participants) of Craig Unit 1 will retire Craig Station Unit 1 by December 31, 2025, as is required by the current Colorado Regional Haze State Implementation Plan. The Yampa Participants also agreed to a September 30, 2028, retirement date for Craig Unit 2. December 31, 2029, was selected as the retirement date for Craig Unit 3 in order to meet carbon reduction goals in 2030.

Q: DID TRI-STATE CONSIDER THE COSTS AND BENEFITS OF EARLY RETIREMENTS OF GENERATION RESOURCES?

A: Yes. In all scenarios, including the base case, Tri-State modeled the previously announced early retirements of Escalante, Craig Unit 1, Craig Unit 2 and Craig Unit 3. In each scenario except the base case, Tri-State enabled modeling consideration of retirement of coal resources prior to their planned early retirement dates or, as applicable, prior to the end of their useful life. In the social cost of carbon scenario, Tri-State enabled modeling consideration of both coal and gas retirements prior to end of useful life or scheduled retirement date. Assumptions related to retirements, which varied by scenario, are outlined in Volume I "Base Case & Alternative Scenario Results" section of the ERP.

Q: HOW DOES THIS ANALYSIS RELATE TO THE BENCHMARKING ANALYSIS YOU DESCRIBED EARLIER IN YOUR TESTIMONY?

A: Whereas the benchmarking analysis is intended to provide information regarding the relative performance of Tri-State's resources compared to generic resources, it does not specifically consider early retirements. Instead, the benchmarking analysis informs the consideration of early retirements by providing information on generation units that may be underperforming.

XIV. <u>ASSESSMENT OF NEED FOR ADDITIONAL RESOURCES</u>

Q: PLEASE DESCRIBE TRI-STATE'S APPROACH TO ASSESSING ITS NEED FOR ADDITIONAL RESOURCES.

A: Tri-State's assessment of the need for additional resources is driven by a number of factors, including early retirement of existing fossil units; Utility Members' load forecasts; RES/RPS requirements; potential for growth in demand-side management and energy efficiency; regulations addressing carbon emissions; implementation of beneficial electrification; and Tri-State's entry into an organized market.

Q: PLEASE DESCRIBE TRI-STATE'S PLANNED RETIREMENTS OF EXISTING RESOURCES.

A: Tri-State retired the Escalante Generating Station in November 2020. Tri-State has announced planned retirements of Craig Unit 1 by December 31, 2025, Craig Unit 2 by September 30, 2028, and Craig Unit 3 by December 31, 2029. Craig Unit 1 and Unit 2 are owned by the Yampa Participants, and the retirement decisions were made jointly by the participants.

Q: PLEASE DESCRIBE THE IMPACT OF TRI-STATE'S LOAD FORECAST ON THE ASSESSMENT OF RESOURCE NEEDS.

A: Tri-State's load forecast of peak demand and firm peak obligations, together with losses and reserve requirements, are compared to existing resources, while accounting for planned retirements and contract expirations, to determine system balance capacity needs.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-25-14

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-59:
Intertek Reliability Study

Update of Reliability and Cost Impacts of Flexible Generation on Fossil-fueled Generators for Western Electricity Coordinating Council

WESTERN ELECTRICITY COORDINATING COUNCIL
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12 May 2020

List of Revisions

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1 | Introduction

The addition of variable generation (VG) places new constraints and costs on conventional generation of power in utility systems, particularly due to an increase in the variability and uncertainty associated with VG. There is a need to include the change in reliability and cost of operating fossil-fueled power plants with operating patterns that include increased generator flexibility.

Fossil-fueled power plants operated in flexible mode are likely to have increased wear and tear on the equipment and/or reliability impacts that do not necessarily occur if the plants were run in baseload operation mode. This is particularly true for power plants designed for baseload operation. A power plant designed for baseload operation typically operates at full load for long periods of time between cold shutdowns. Critical components operate at design temperatures, with temperature imbalances which occur only at that load. Startups and shutdowns are infrequent, and the load ramp rates consistent, so fatigue damage is less of a concern.

Flexible or cycling operation, on the other hand, requires several different modes of operation: two-shifting, load following, and low load operation, as well as frequent startups (hot, warm, and cold), faster ramp rates, and more thermal cycles than originally designed for. Temperature imbalances may be exacerbated by operation at non-optimum, non-design loads. Temperature differences between components may cause flexibility issues and subsequent fatigue damage.

The Western Electricity Coordinating Council (WECC) and the Production Cost Model Data Work Group are seeking to update the estimate of the cost of flexible generation and reliability impacts on the conventional fossil-fueled generators for operation in calendar year 2030.

Intertek AIM (previously Aptech Engineering Services) had provided an estimate of increased wear and tear costs and reliability impacts to WECC [Intertek Project AES 11077831-2] and National Renewable Energy Laboratory (NREL) [Contract No. DE-AC36-08GO28308].[1]

In our previous study, Intertek AIM had organized the results by the following eight generator plant types in the following eight groups:

1. Small coal-fired sub-critical steam (35-299 MW)
2. Large coal-fired sub-critical steam (300-900 MW)
3. Large coal-fired supercritical steam (500-1300 MW)
4. Gas-fired combined-cycle plants (combustion turbine (CT)-steam turbine (ST) and heat recovery steam generators (HRSG)
5. Gas-fired simple cycle large frame (GE 7/9, N11, V94.3A, and similar types)
6. Gas-fired simple cycle Aero-Derivative CT (LM 6000, 5000, 2500)
7. Gas-fired steam (50-700 MW)
8. Retrofitted coal-fired steam (plants retrofitted to provide load following or regulation) – these plants should be parsed by size/type same as Types 1 through 7.

[1] https://www.nrel.gov/docs/fy12osti/55433.pdf

The primary task of the study included the estimation of "lower bound" cycling cost data for the above identified groups of generator plant types, including the following:

- Hot, warm, and cold start costs
- Baseload variable operations and maintenance (VOM) costs

Figure 1 was a key output of the analysis showing the spread of cycling-related costs.

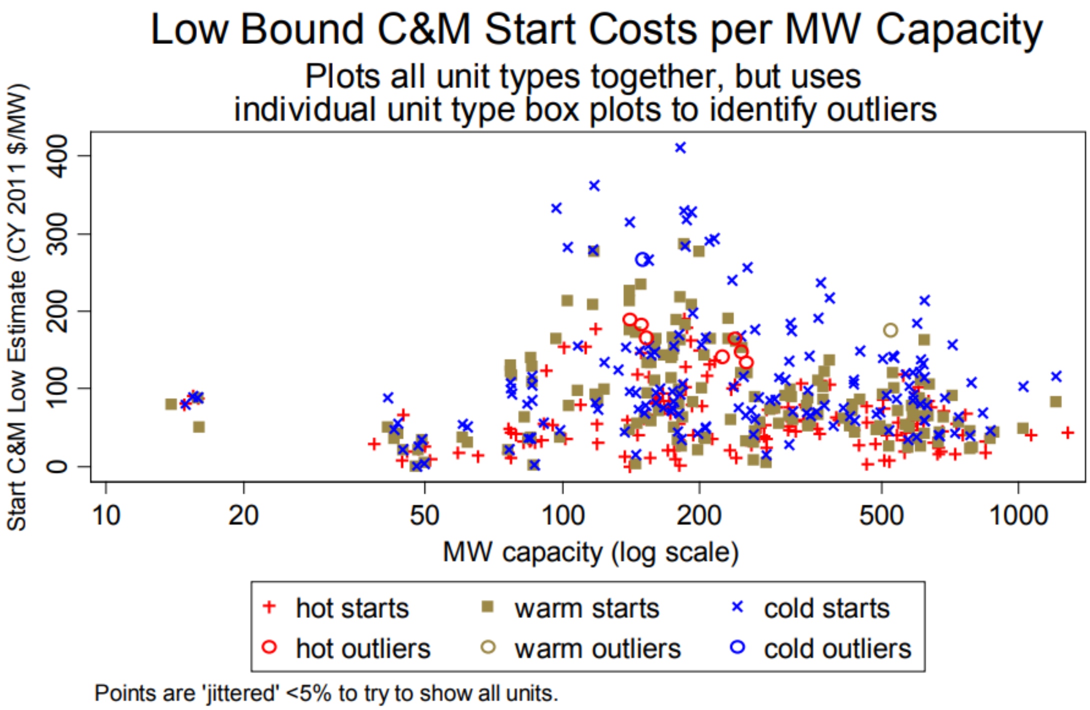


Figure 1 — Lower Bound – Capital and Maintenance Start Costs per MW Capacity.

Background

Since Intertek AIM and WECC collaborated on this work in 2011, several changes have occurred with respect to power plant operating profiles and technologies. Further, different regions in the U.S. have witnessed different outcomes from the integration of VG.

A combination of market deregulation, increasing VG, changes in fuel prices, and other factors have forced operators to cycle aging fossil units that were originally designed for mainly base load operation. As shown in previous studies, all fossil generators can perform cycling operation, but the impact of cycling on wear and tear cost or damage and the reliability of the plants from the cycling differs from one unit to another (see figure 1).

Intertek AIM has performed evaluation of the evolving operating regime of several hundred power plants in the U.S.[2] As an example, Figure 2 shows the change in operating mode of the fossil generation fleet in California from 2005 to 2015. The change in operating profile is largely driven by the rapid increase in solar generation in the state. Solar generation in the state forces the natural gas fleet in California (about 40% of capacity) to operate with increased cycling. Fossil units are staying offline for more hours in 2015 compared to 2005, and when they are online, they typically ramp up to full load (as solar generation falls at night). There is also a trend of increased operating hours at lower loads in 2015 versus 2005.

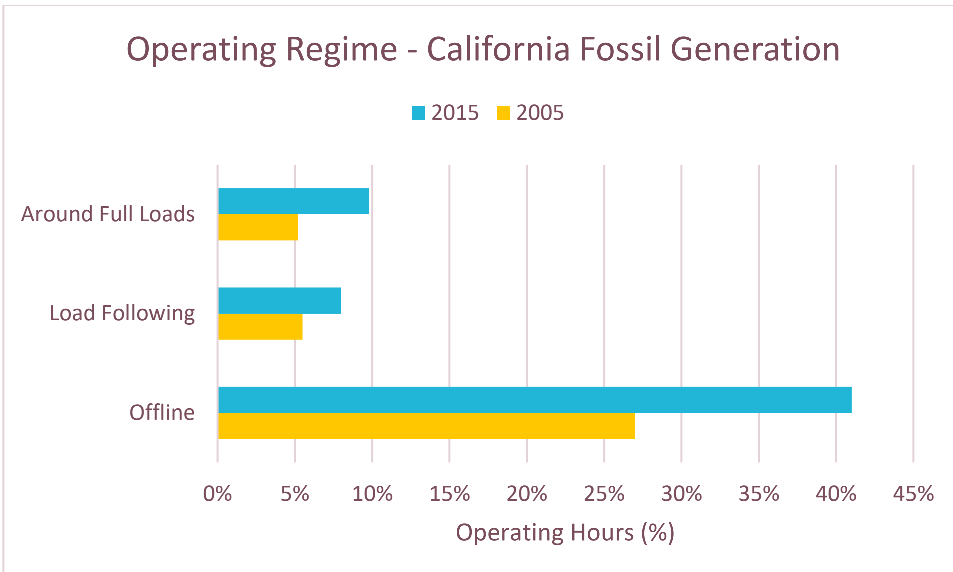


Figure 2 — Operating Regime of California Fossil Generators (2005 vs. 2015).

Characterizing fossil power generation impacts from large VG on the grid requires an understanding of the operating regime of the power plants. Further, the analysis should cover a long enough time horizon to account for the "time lagged" wear and tear damage on fossil generation equipment. When a power plant is relatively new, there is a much larger time lag between increased cycling and failures, compared to an older plant[3]

Flexible generation or cycling refers to the operation of electric generating units at varying load levels, including on/off and low load variations, in response to changes in system load requirements. Every time a power plant is turned off and on, the boiler, steam lines, turbine, and auxiliary components go through unavoidably large thermal and pressure stresses, which cause damage. This damage is made worse by the phenomenon we call creep-fatigue interaction. Creep and fatigue are terms commonly used in engineering mechanics. Creep is time-dependent change in the size or shape of a material due to constant stress (or force) on that material. In fossil power plants, creep is caused by continuous stress that results from constant high temperature and pressure in a pipe or tube occurring during

[2] Impact of Large-Scale Wind & Solar Integration on Existing Fossil Generation in United States, N. Kumar et al., 15th Wind Integration Workshop, Vienna (2016)

[3] "Power Plant Cycling Costs," N. Kumar et al. http://www.nrel.gov/docs/fy12osti/55433.pdf.

steady-state base load operation. Fatigue is a phenomenon leading to cracking and possible fracture (failure) when a material is under repeated, fluctuating stresses. In a fossil power plant, such fluctuating stresses result from large transients in both pressures and temperatures. The worst of these transients typically occur during cyclic operation. Because base load fossil units are designed to operate in the creep range, they experience increased outages when they are additionally subjected to cycling-related fatigue. The term creep-fatigue interaction suggests that the two phenomena (creep and fatigue) are not necessarily independent, but act in a synergistic manner to cause premature failure. In fact, materials behave in a complex manner when both types of stresses occur.

Relating this discussion to power plants, if an older, base loaded plant (that used to have three to six starts per year and is at 40 to 80% design life from creep damage) is now suddenly dispatched to operate at 50 starts per year, it may take only 2 to 6 years to cause component failures. Thus, while cycling-related increases in failure rates may not be noted in the first months, critical components will eventually start to fail. Shorter component life expectancies will result in higher plant equivalent forced outage rates (EFOR) and/or higher capital and maintenance costs to replace components at or near the end of their service lives. In addition, cycling increases may result in reduced overall plant life. How soon these detrimental effects will occur will depend on the amount of creep damage present and the specific types and frequency of the cycling.

As a power plant ages, the equipment degrades even though it is maintained and inspected and is unable to perform as well as brand new equipment. It becomes necessary to upgrade or replace degraded equipment to "new condition". For example, even though condensers are cleaned annually or more often, condenser retubing becomes necessary every 10 or 15 years. In other words, maintenance is necessary to minimize the effect of equipment degradation with age and operating regime. With cycling operation, some components face accelerated life degradation from the effects of aging and the off-design operations.

Capital expenses, as well as variable and fixed operations and maintenance (O&M) costs at a generating facility, can be analyzed to assess maintenance and equipment replacements at a power plant and determine the current condition. Costs associated with plant cycling and the impact of the cycling on reliability can also be gauged and quantified. Plants that have underspent on capital and/or O&M are likely to suffer with lower historical reliability or are at risk of future forced outages.

The unit's specific analysis results depend heavily on the regression analysis of the costs versus cycles and the unit signature data during cyclic operations including the range of all load changes. A comprehensive methodology to determine the cost associated with plant cycling has been discussed in recent renewable integration studies.

The increased incremental costs that are attributed to cycling are broken down into the following categories[4]:

1. Increases in maintenance and overhaul capital expenditures.
2. Forced outage effects including forced outage time, replacement energy, and capacity.

[4] Lew, D.; Brinkman, G.; Ibanez, E.; Florita, A.; Heaney, M.; Hodge, B.-M.; Hummon, M.; Stark, G.; King, J.; Lefton, S.A.; Kumar, N.; Agan, D.; Jordan, G.; Venkataraman, S. (2013). The Western Wind and Solar Integration Study: Phase 2. NREL/TP-5500-55588. Golden, CO: National Renewable Energy Laboratory. Accessed May 2, 2014: http://www.nrel.gov/docs/fy13osti/55588.pdf.

3. Efficiency, both long-term losses as well as operational losses associated with startups and low/variable loads.
4. Cost of startup fuel, auxiliary power, chemicals, and extra startup manpower.

Report Goals

WECC's Production Cost Model Data Work Group required Intertek AIM to update the cost and reliability impacts estimated in the 2012 study for modes of operation in calendar year 2030.

The following technical approach was used to quantify the wear and tear cost impacts:

- Characterize historical operations of thermal units within WECC.
- Evaluate and control for recent and projected power plant Capital Expenditures (CapEx) and Operating Expenditures (OpEx)
- Calculate changes to cycling duty and the potential impacts on wear and tear costs, as well as reliability impacts.

The results presented in this report include the following generation types:

1. Small coal-fired sub-critical steam (35-299 MW)
2. Large coal-fired sub-critical steam (300-900 MW)
3. Large coal-fired supercritical steam (500-1300 MW)
4. Gas-fired steam (50-700 MW), includes both supercritical and subcritical technologies
5. Gas-fired simple cycle large frame (GE 7/9, N11, V94.3A, and similar types)
6. Gas-fired simple cycle Aero-Derivative CT (LM 6000, 5000, 2500). New data set to include, New Fast Start Gas Turbines – Aero-Derivative (LMS 100 and similar)
7. Gas-fired combined-cycle plants (CT-ST and HRSG) – Conventional[5]
8. Gas-fired combined-cycle plants (CT-ST and HRSG) – High Efficiency Gas Turbines (H Class and Similar)
9. Gas-fired combined-cycle plants (CT-ST and HRSG) – Fast Start
10. Gas Reciprocating Engines

Intertek AIM has limited the sample size of units to the Western Interconnect where reasonable; however, we have included other U.S.-based power plants if sample size is small.

[5] F-Class based machines. F-class turbines are typically in the 170-230 MW range. Products include GE's 7F.03-.05 models, Siemen's SGT6-5000F, and Mitsubishi Hitachi's M501F

The results of the projected 2030 cost of cycling and reliability impacts will be provided in the following format:

- **Hot, Warm, and Cold Start Costs**

  Costs per start for hot, warm and cold starts (2020$).

  Physical Constraints: Intertek AIM will also provide typical ramping capabilities, minimum up and down time, startup time for the different generation technologies, and the corresponding cost impacts.

- **Load Following Costs**

  Costs for various load following modes – mild, significant, and operation at minimum load (2020$).

  Minimum load operation to be evaluated may be at approximately 80%, 50%, and 30% of maximum load. Generation technologies that are unable to operate below any minimum load operation described above will be noted. These costs will inherently include all cycling-related costs (except forced outage costs).

  Physical Constraints: Ramping capabilities at various low loads will be listed, including cost impacts.

- **Base-loaded Variable O&M Costs**

  Intertek AIM determines the cycling-related O&M cost (listed above) and subtracts that from the total O&M costs to generate a baseload VOM cost. These costs assume a power plant running at steady load without any on/off cycling. This will ensure no double counting of VOM costs in WECC's production cost modeling.

- **Reliability Impacts**

  While cycling, increases in failure rates may not be noted immediately, critical components will eventually start to fail. Shorter component life expectancies will result in higher plant EFOR and/or higher capital and maintenance costs to replace components at or near the end of their service lives. Intertek AIM will provide the expected "lower-bound" increase in EFOR (in added percentage for a single year) due to each cycle type.

2 | Flexible Generation Costs and Reliability Impacts

Calculated cycling costs for typical load cycles of any power plant unit are recorded by Intertek AIM as the total present-valued future cost of the next "incremental" cycle.

These numbers are best estimates based on the assumption that the overall amount of cycling (i.e., equivalent hot start (EHS) per year) continues at no more than 75% of the level of past operations. If the amount of cycling of a given unit increases dramatically, the cost per cycle would also increase due to nonlinear creep-fatigue interaction effects.

However, if CapEx and OpEx spend is reduced for any reason, such as an impending retirement of the asset, then the net cost of cycling is reduced. The reduced spend will manifest as reduced reliability. Such trends have been observed at other sites assessed by the author.[6]

Basic Premise

Maintenance requirements are based on an assessment of hours of operation or cycling of a unit (besides any reactionary events). Major costs for each inspection are for labor, consumables, and capital replacement parts. Labor is the extra manpower needed to perform the inspection. The consumables are material which will be used during the inspection or maintenance activity, such as gaskets, welding products, etc. Capital replacement parts are the parts that are examined for corrosion and wear during each inspection. Generally, the capital replacement costs dominate the overall ratio of costs, as this is primarily to counter for the life shortening effects of aging or additional cycling.

Cost is one of the key factors influencing the choice of fuels and technologies used to generate electricity. Capital, maintenance, operating, and financing costs often vary significantly across technologies and fuels. In addition, regional differences in construction, fuel, transmission, and resource costs mean that location also matters. Because electricity prices differ throughout the day, the timing of a plant's output affects its cost recovery.

The underlying premise of Intertek AIM's approach is that cycling directly causes a significant proportion of annual non-fuel unit costs. For economic modeling, the independent cycling-related variable was taken to be equivalent hours of operation.

Costs per Start

The desired result is an estimate of the cycling cost elements combined to determine the effect of an additional equivalent start. Intertek AIM's methodology brings all future forecasted costs to their present value using the client's discount rate, cost escalation factor (or simply inflation rate), and aging effects.

[6] Cochran, Jaquelin, Debra Lew, and Nikhil Kumar. Flexible Coal: Evolution from Baseload to Peaking Plant. NREL, 2013 https://www.nrel.gov/docs/fy14osti/60575.pdf

The present value of future wear and tear cycling costs for the plant equipment is the sum of two components: added costs and accelerated costs:

- Specifically, the first component, adding costs, is the cost of extra cycling-related maintenance necessary to avoid shortening of the component's life caused by an additional start.

- The second component, accelerated costs, is the cost of "moving up" future maintenance costs in time (i.e., maintenance costs occur sooner) caused by adding one "start". Adding a "start" to a unit's operation will cause the time required before maintenance is needed to decrease. Thus, this second component represents the present value of the acceleration of costs incurred for ordinary maintenance costs due to an additional start, especially overhaul costs and other large non-annual costs.

Further, it is important to highlight the impact of life shortening as a result of increased flexible operation. Increased cycling can have a significant life-shortening impact on certain units. This cost element can be significant for units that are near their end-of-life, but less important in cases of planned retirements. Note that as long as capital and maintenance expenditures are made to counter cycling effects, this cost element will be small compared to such costs as maintenance and extra fuel. In other words, the cost of maintenance is essentially countering the effects of life shortening over time.

It is important to note that since not all subsystems have the same life expectancy; targeted spending patterns for critical subsystems are required. Intertek AIM looks at both total spending and spending patterns to determine if current and projected critical subsystem spending is enough to maintain efficiency and reliability.

Table 1 provides definitions of costs included in the wear and tear estimates.

Table 1 — Definitions of the Cycling-related Costs

	Cost Includes	Cost Excludes
Cost of O&M	• Operator non-fixed labor • General engineering and management cost (including planning and dispatch) • Maintenance and overhaul maintenance expenditures (preventative and scheduled) for boiler, turbine, generator, air quality control systems, and balance of plant key components	• Fixed labor • Fixed maintenance and overhaul maintenance expenditures for boiler, turbine, generator, air quality control systems, and balance of plant key components • Preventative maintenance and routine maintenance on auxiliary equipment like buildings, HVAC, etc.
Cost of Capital Maintenance	• Overhaul capital maintenance expenditures for boiler, turbine, generator, air quality control systems, and balance of plant key components	• Replacement due to obsolescence • Preventative maintenance and routine maintenance on auxiliary equipment like buildings, HVAC, etc.

Damage Modeling & Cost Estimation

Intertek AIM's full comprehensive top-down and bottom-up methodologies for estimating cycling costs provide better and high confidence estimates, which require extensive cost and operational data. That approach models the relationship between total cycling costs (wear and tear, EFOR, startup costs, etc.) and historical cycling operations for the unit or plant. To set up and run a complete cost of cycling program, we require 8 to 10 years of cost and hourly megawatt and plant reliability data as a minimum. In the absence of these required considerable data, we have found that a reasonable (though less accurate) method is to "benchmark" or measure the cost estimates from those units against those from similar units previously analyzed for which we have completed the more rigorous cost estimate methodology with detailed information.

Figure 3 shows the overview of our process to estimate lower bound cycling costs.

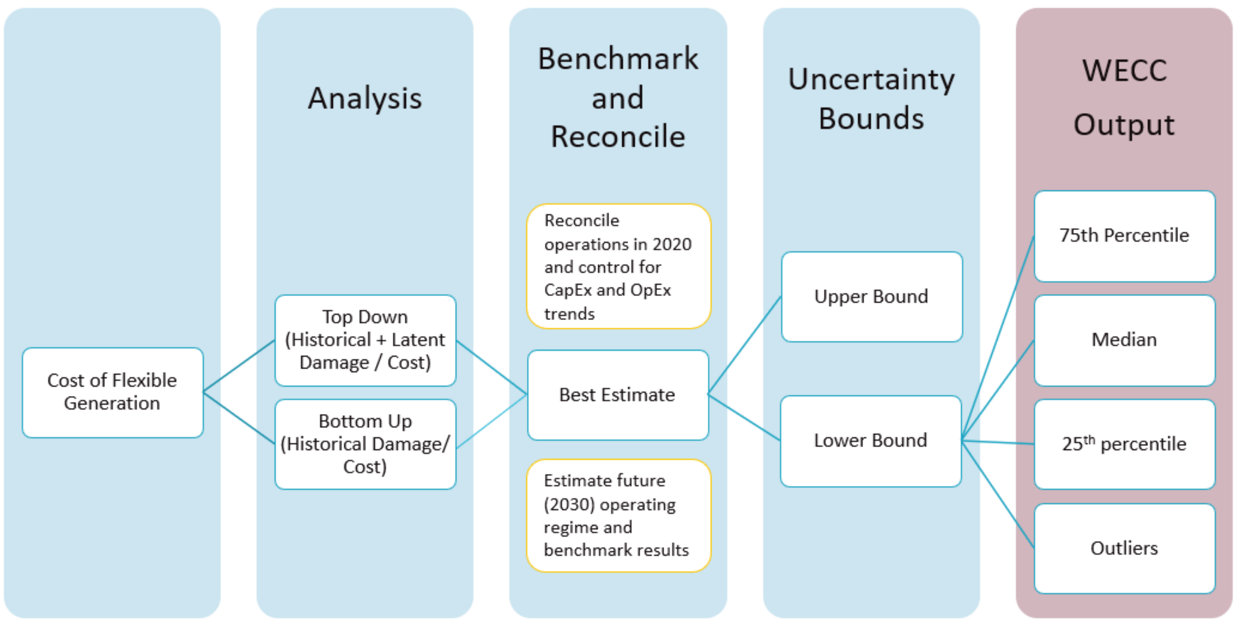


Figure 3 — Lower Bound Cost Estimation Methodology.

To establish the reference unit cycling costs, we used our top-down methodology. We used elaborate statistical models to develop "lower bound" estimates of the total unit equipment damage costs due to cycling, which include the incremental wear and tear costs and the capitalized maintenance and O&M costs in the full-blown, top-down cost of cycling analysis. The results of these statistical analyses are then used as benchmarks for calculating the cycling costs presented in this report.

The control variables in our benchmarking approach are listed below:

- Size — We defined size by the megawatt capacity of generators for the unit (for combined-cycle units, we sum the capacities of the ST and gas turbine(s)).

- Cycling rate and age — These factors account for unit age and for differing annual and cumulative rates of cycling damage expressed in EHS, as measured using Intertek AIM's damage algorithm – Loads Model[7].
- Vintage and design characteristics — Some technologies are better suited to operate flexibly (example, gas turbines or reciprocating engines).
- Typical cycle damage ratio (in units of EHS per cycle) — The ratio of the average damage for the subject unit's start or load follow to that of the benchmark unit; again, as estimated using the Loads Model, the cycle ratios for each start type (hot, warm, and cold) and load follow are considered, along with typical load follows.
- Annual plant maintenance costs — Plant maintenance and capitalized maintenance costs of benchmarked units were compared to the top-down reference unit costs.
- Reliability — Flexible operation, as well as aging of equipment, influence reliability.

Operating Profile of Different Generation Technologies

An important step in estimating cycling costs and reliability impacts is to characterize the operating regime of the 10 groups of generation technologies. The next series of charts shows the operating regime of the coal steam and combined-cycle generation technologies over a 20-year horizon. Highlights from the analysis are:

- On average, the coal steam units have not witnessed increases in on/off cycling; however, they are operating with increased load following. Figures 4 and 5 highlight the operation of the sample of subcritical coal units within WECC. Evidently both the large and small coal units are operating more hours at lower loads in the recent years, and while the number of starts has not trended higher, when the units do go offline, they stay off for longer periods (cold starts).
- Simple cycle CTs continue to perform as peaking units, with low capacity factors. The generation peaks in the summer months as expected and shown in Figure 6.
- The combined-cycle fleet, with lower natural gas prices and a growing share of the overall grid capacity have transitioned to more baseload operation. Figure 7 shows the annual starts for a sample of conventional combined-cycle, newer high efficiency and fast start combined-cycle units.

[7] An EHS is Intertek AIM's unit of cycling intensity. One normal hot start and shutdown cycle would produce about one EHS. One abrupt hot start with especially damaging ramp rates and other load range characteristics would produce well over one EHS, as would most warm starts and all cold starts. The usually more numerous load follow cycles each typically produce a small fraction of an EHS.

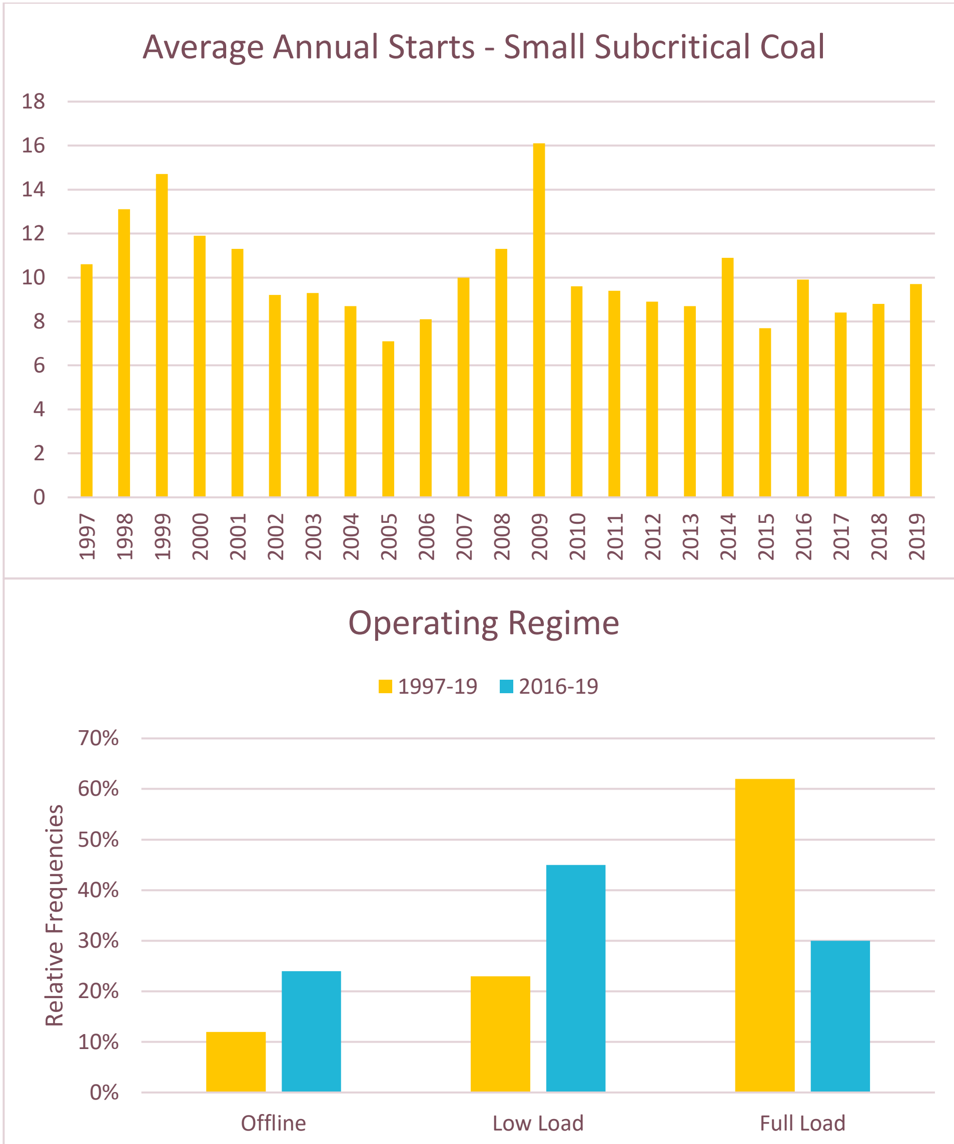


Figure 4 — Small Subcritical Coal (<300 MW) Operating Regime.

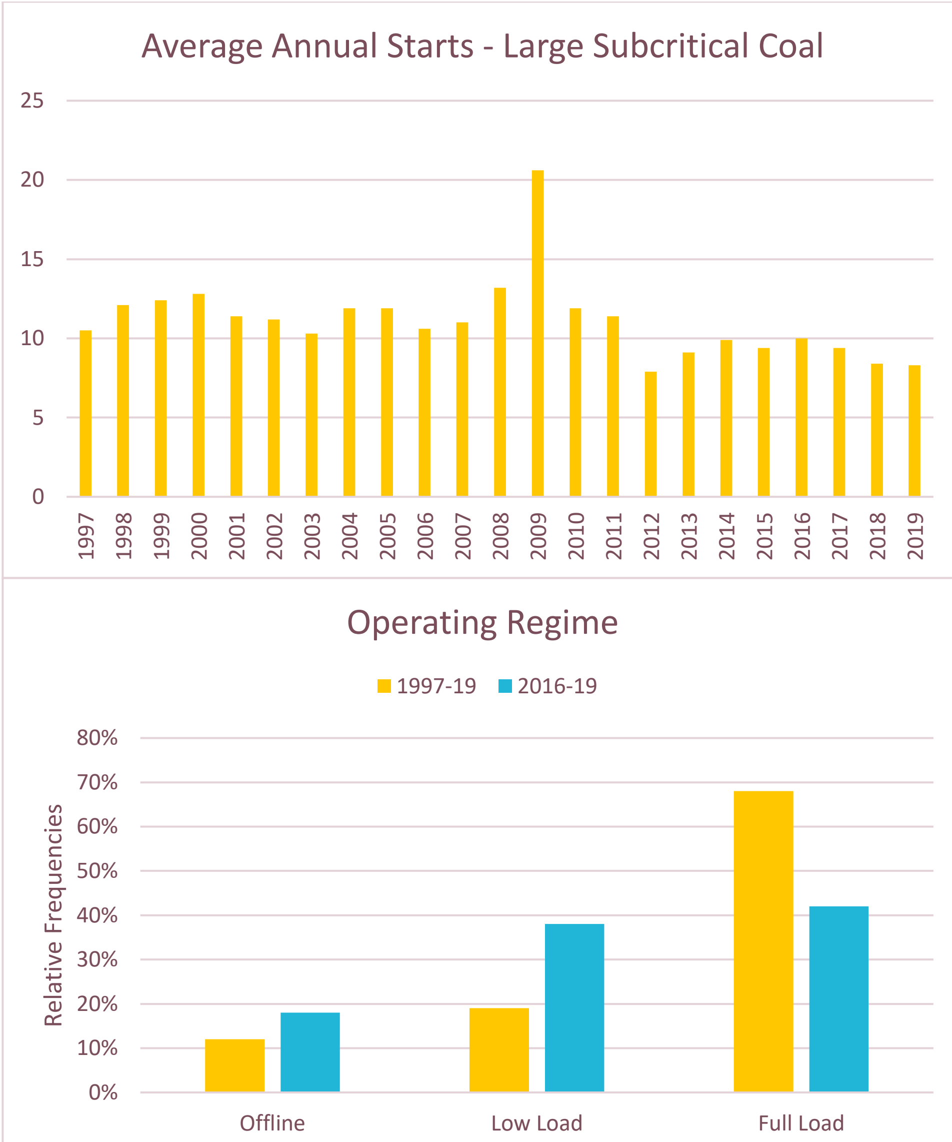


Figure 5 — Large Subcritical Coal (>300 MW) Operating Regime.

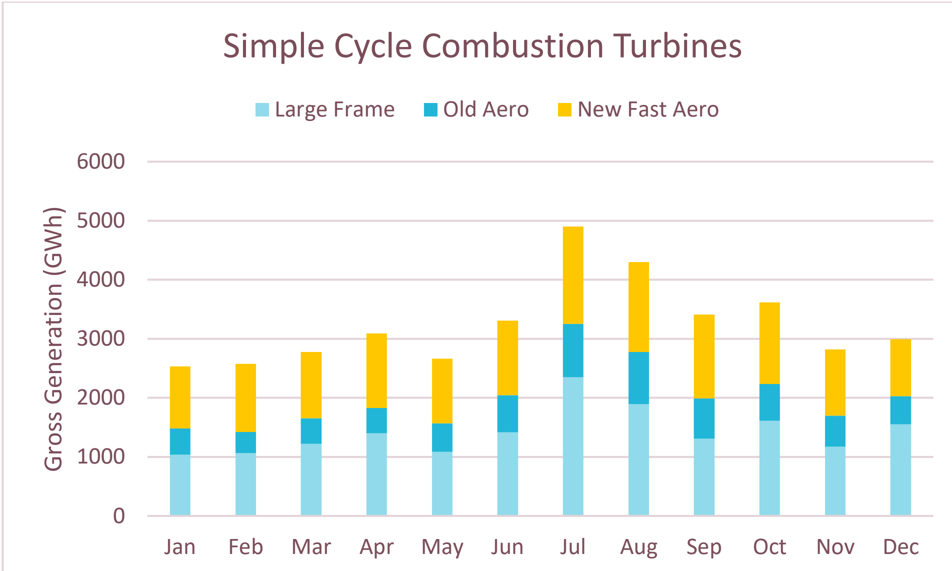


Figure 6 — Simple Cycle CT Monthly Operating Regime.

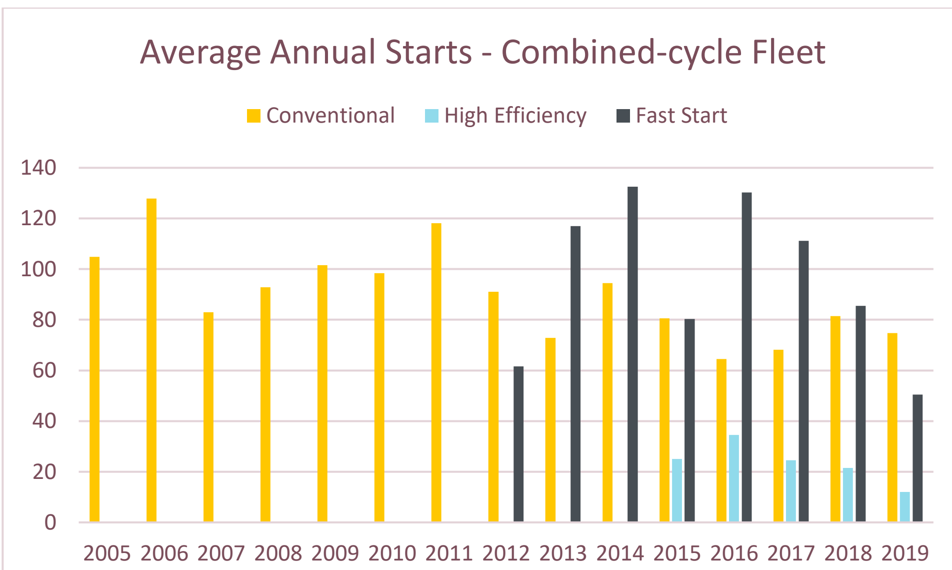


Figure 7 — Annual Starts – Combined-cycle Fleet.

Flexible Generation Impacts and Results

Power plant operations that start, stop, cycle, two shift, base load, and operate above a unit's rating have a quantifiable impact on component life and on total associated unit operating costs. The true costs of cycling and low load operations are often not known or not well understood because of the complex effects of these operations on additional capital and/or maintenance spending requirements, increased EFOR, increased heat rate, and reduced life effects.

Figure 8 shows a risk chart from a small sample of units that show a relation between cycling and forced outage rates. To help reduce the clutter in the chart, some key units have been highlighted to illustrate the impact of cycling on forced outage rates for different design units[8].

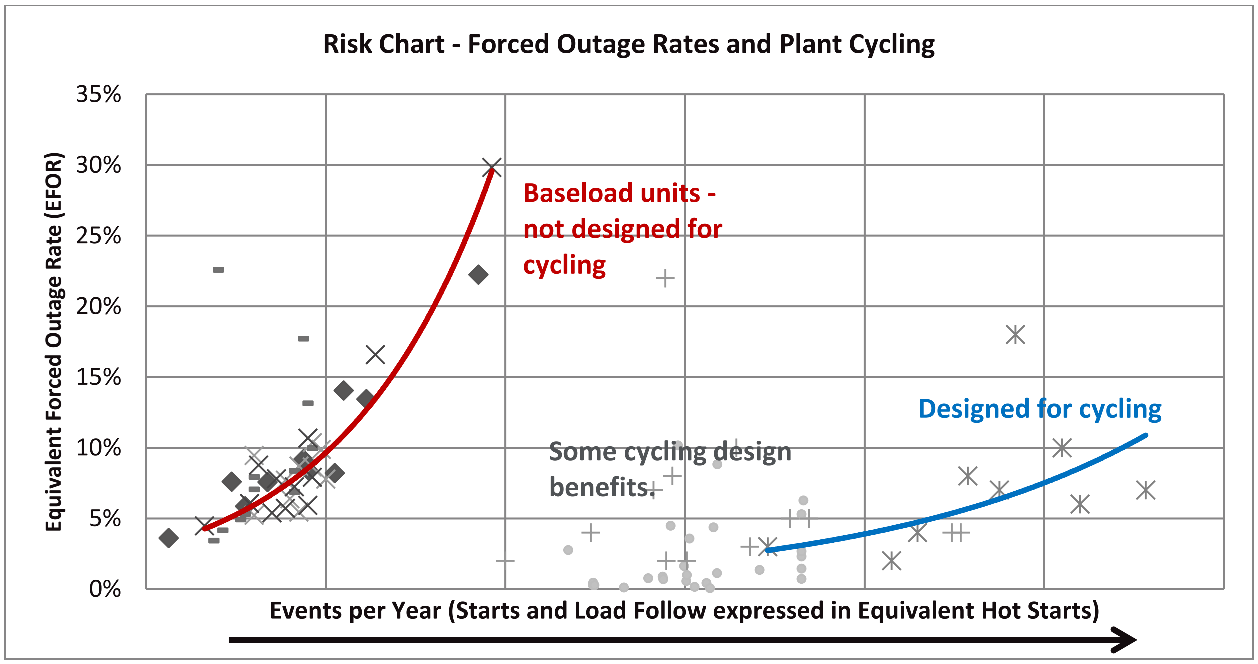


Figure 8 — Flexible Generation and Reliability Impacts.

Even when a unit is thought to be properly designed for cycling, there are external effects in the balance-of-plant design, water chemistry, etc., that make some units more susceptible to cyclic damage than others.

Another risk factor for an aging fleet of fossil generators is High Impact Low Probability (HILP) events. With increased cycling and an aging plant, operators of older assets, conventional steam as well as older combined-cycle units, are putting the units at increased risk of increased forced outages and HILP events. Older units have a much higher chance of experiencing HILP-related forced outages. Figure 9 shows hazard rates for aging power plants. Intertek AIM analyzed NERC GADS data and defined a HILP as a full forced (i.e., unplanned) outage greater than 350 hours.[9]

[8] Impact of plant cycling on availability, N. Kumar et al., ASME Power 2015, POWER2015-49359

[9] Impact of Aging on Power Plant Reliability, N. Kumar and P. Besuner, Intertek Engineering Technical Paper 214

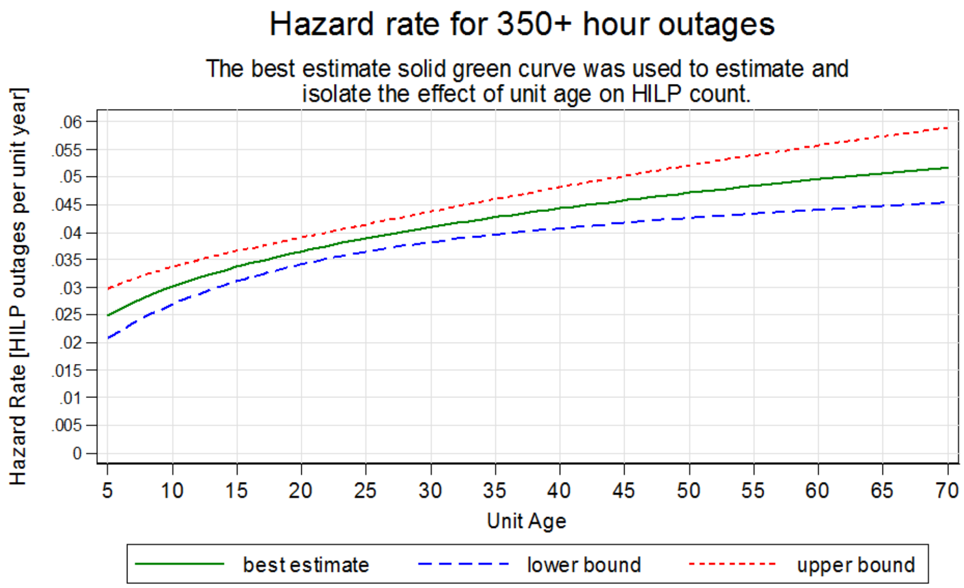


Figure 9 — Hazard Rate for HILP Outages.

Costs associated with plant cycling and the impact of the cycling on reliability can also be gauged and quantified. As a power plant operates with increased cycling and ages, the equipment degrades even though it is maintained and inspected and is unable to perform as well as brand new equipment. It then becomes necessary to upgrade or replace degraded equipment to "new condition."

Increased maintenance spend is necessary to minimize the effect of equipment degradation with age and changing operating regime. Plants that have underspent on capital and/or O&M are likely to suffer lower historical reliability or are at greater risk of future forced outages. As discussed earlier, Intertek AIM assessed the existing fleet operations within WECC to estimate accumulated cycling damage, and then benchmarked cost of flexible generation to reference units in our database. Over time, most North American operators have tended to minimize O&M spend.

Figure 10 shows the historical trend of real O&M for all plants and weighted by generation has decreased from 1990-2005 and has leveled out in recent years. Highlights of our analysis are discussed below: [10]

- While O&M spending is levelling off, capital costs are much higher than any other costs covered in our analysis. Essentially, even with extensive maintenance, the performance of the equipment will deteriorate over time to the point where it must be replaced.
- Coal power plant O&M has not been very high but there are some signs of increased coal O&M among the oldest plants. This tendency to keep O&M costs down for coal plants may also explain Intertek AIM's observation and analysis of increased forced outages with age.
- Combined-cycle units tend to have lower O&M spend, particularly in recent years.

[10] Power Plant O&M Spend in U.S. – Trends and Impact, N. Kumar & P. Besuner Intertek Technical Paper 305

- There are observed variations in O&M costs by state. California is an exception to low overall western state O&M costs, with moderately high O&M spending; but well below that of some of the highest O&M states in the U.S.

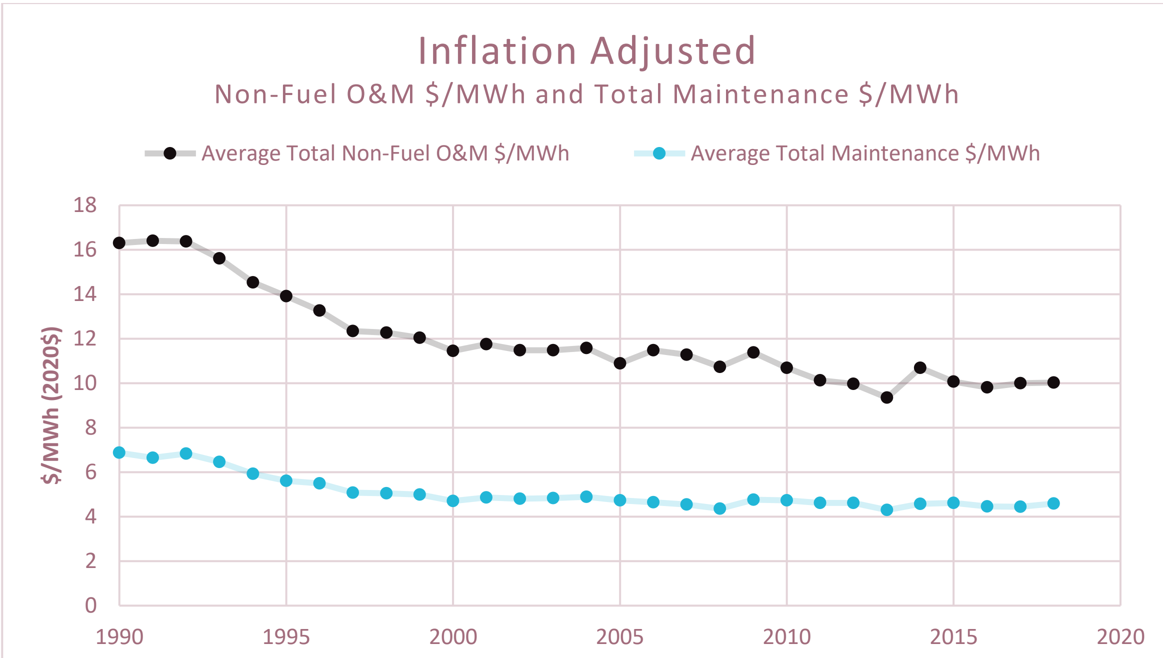


Figure 10 — Historical Non-fuel O&M Spend.

Finally, we referenced the U.S. Energy Information Administration (EIA) Annual Energy Outlook 2020 to forecast likely operating regime of the various fossil generation technologies in 2030[11].

The general trend discussed by the EIA, and our own assessment forecasts that:

- While there will be additional coal generation retirements by 2030, the remaining higher efficiency (thermal or economical) coal units will tend to operate similar to how they operate in 2016-2019 (Figures 4 and 5). However, these units are likely to suffer from lower O&M spend, increased offline hours, and deterioration of reliability as these units age.
- Simple cycle CTs and reciprocating engines are designed for cycling operation, and the operating profile will not differ significantly in 2030. Also, by definition, a majority of the VOM spend on these units is associated with cycling operation, which is reflected in our results.
- Conventional combined-cycle units would have accumulated several thousand hours of operation, as these units continue to operate more baseload. By 2030, several of these units would be over 25 years old, with competition from newer higher efficiency units, and therefore likely to operate with more on/off cycling. Per the EIA, "The currently most common combined-cycle units, with their

[11] https://www.eia.gov/outlooks/aeo/

lower efficiency, and the new single-shaft (1 x 1 x 1 configuration) combined-cycle units decline in utilization as a group, from 56% in 2020 to 36% by 2035".

- Fast start combined-cycles will see modest increase in on/off cycling, while the higher efficiency combined-cycle fleet will predominantly operate as they do now.

Results

Table 2 shows the physical constraints and capabilities of the ten (10) generation types analyzed:

- As expected, the simple cycle aeroderivative CTs and the reciprocating engines provide significant flexibility, with fast ramping capabilities and relatively short down times. Reciprocating engines have extremely fast ramp rates and can get up to full load at a ramp rate of 50% (as a percent of Gross Dependable Capacity (GDC)) per minute. Large frame CTs are not quite as flexible as aero derivative machines.
- Coal units have improved the low load capabilities, and more so on the larger subcritical coal units. Coal steam units are limited in terms of gas/oil support availability and/or number of mills in operation at low loads. Larger units have been able to improve low load operation from about 50% in the past to about 35-40% minimum load (as a percent of GDC). Coal units are also less flexible in terms of startup times and up times. Some units have been transitioning to sliding pressure operation, which may limit ramping response.[12]
- The median age of operating gas steam units is over 55. Most of the units in WECC are subcritical and have low capacity factors (<30%). Typically, these units perform no more than 40 starts a year and are utilized infrequently. The units can operate at low loads (around 20-30%) for extended periods of time but are not as efficient and used sparingly. These units are also operated with ramp rates that are significantly higher than coal steam units.
- Combined-cycle units typically have a minimum emissions compliance load, which limits the operating range. Multiple gas turbine configuration on these units lend increased flexibility in operation. Some of the new higher efficiency combined-cycle units are, however, in 1x1 configuration and operate mostly baseloaded. The ST is often a limiting factor for high ramp rates, and unless the plant is designed for cycling operation (e.g., bypass system), the units tend to have some limitations in terms of flexibility.
- Fast start combined-cycle units have HRSGs with a Benson® high pressure section or are single-pressure non-reheat units that minimize damage on the components. These units also might take advantage of the shutdown purge sequence (in compliance with NFPA® 85) to improve startup times.
- The high efficiency combined-cycle units can achieve efficiencies in excess of 60%. These units are typically constrained on ramp rates as well as low loads.

The values presented in Table 2 are for typical power plants and do not include units that may have been retrofitted or best in class.

[12] https://www.babcockpower.com/wp-content/uploads/2018/02/constant-and-sliding-pressure-options-for-new-supercritical-plants.pdf

Table 2 — Capabilities and Physical Constraints of Fossil Generators

Unit Types	Coal - Small Sub Critical	Coal - Large Sub Critical	Coal - Super Critical	Gas - Steam	Gas - Large Frame CT	Gas - Aero Derivative CT	Typical CC [GT+HRSG+ST]	High Eff. - CC [GT+HRSG+ST]	Fast Start - CC [GT+HRSG+ST]	Gas - Recip. [per Engine]
Time (min)										
Minimum Up Time	720	720	1440	120	60	60	120	120	60	30
Minimum Down Time	360	480	480	240	60	30	360	480	360	15
Startup Ramp Rate (%GDC/min)										
Typical - almost no diff. by start type	2.0%	3.5%	3.5%	10.0%	10.0%	90.0%	6.0%	5.5%	8.0%	95.0%
Turndown Ramp Rate (%GDC/min)										
Don't see significant changes in rates for level of turndown. However, some steam units use sliding pressure.	5%	8%	8%	20%	15%	90%	10%	10%	15%	95%
Minimum Load (% GDC)										
Typical	40%	35%	45%	20%	50%	50%				-
1x1							48%	48%	48%	
2x1							25%	25%	25%	

Tables 3 and 4 below present the lower bound cycling cost results for the ten (10) unit types for projected operations and annual spend in 2030. As with our analysis in 2012, it should be emphasized that there are large variations in costs between individual units of each type, and that the results provided by Intertek AIM are *low bounds*[13].

All cost numbers in this report have been adjusted for calendar year 2020$.

Use of the generic lower bound costs, without accounting for actual unit operations and spend can result in significant under/over estimation of power plant cycling costs.

Table 3 presents the typical load following costs for three different operating regimes: mild load change (20% of GDC); typical load change (for each unit type); and minimum load operation. Figure 11 presents the same information in a graphical form. The load following costs are not significantly impacted by modest changes to ramp rates. In our assessment for load follow operation, an increase of 25% will have no measurable increase in costs. However, doubling of current ramp rates on the steam units (limited by design) will result in increased costs as indicated in Table 3. For the gas turbine-based technologies, the original equipment manufacturer limits ramp rate capabilities, and typically there is little leeway for operators to increase these rates (without control upgrades, or retrofits).

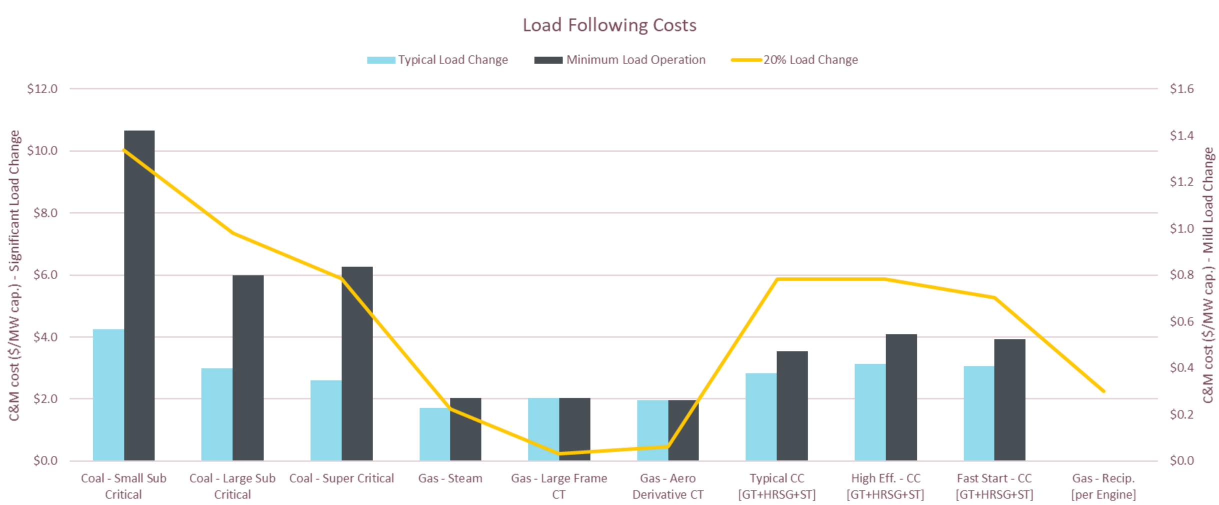


Figure 11 — Load Following Costs.

Note: Mild load change costs are shown on the secondary y-axis.

[13] Care should be taken to implement the lower bound cycling cost. For example, if a unit goes through 200 starts per year and the start cost is underestimated by $1,000/start, then the annual cost of this erroneous number can be significant. Moreover, if this unit is indeed cycled on/off more often due to the lower cost estimate, then it would accumulate damage at a significantly higher rate.

Table 3 — Projected 2030 Load following cost estimates (lower bound, 2020$)

Unit Types	Coal - Small Sub Critical	Coal - Large Sub Critical	Coal - Super Critical	Gas - Steam	Gas - Large Frame CT	Gas - Aero Derivative CT	Typical CC [GT+HRSG+ST]	High Eff. - CC [GT+HRSG+ST]	Fast Start - CC [GT+HRSG+ST]	Gas - Recip. [per Engine]
Typical Load Follows Data										
-C&M cost ($/MW cap.) - 20% Load Change										
Median	1.34	0.98	0.78	0.22	0.03	0.06	0.78	0.78	0.70	0.30
~25th_centile	0.76	0.56	0.61	0.14	0.02	0.04	0.37	0.37	0.33	0.25
~75th_centile	1.54	1.24	0.95	0.27	0.05	0.14	0.90	0.90	0.81	0.40
-C&M cost ($/MW cap.) - Typical Low Load										
Median	4.26	2.99	2.61	1.70	2.03	1.96	2.84	3.13	3.06	
~25th_centile	2.44	1.71	2.02	1.04	1.20	1.31	1.33	1.47	1.44	
~75th_centile	4.90	3.79	3.17	2.06	3.57	5.28	3.29	3.61	3.54	
-C&M cost ($/MW cap.) - Minimum Load										
Median	10.66	5.98	6.27	2.02	2.03	1.96	3.55	4.08	3.92	
~25th_centile	6.10	3.42	4.86	1.23	1.20	1.31	1.67	1.91	1.84	
~75th_centile	12.26	7.57	7.61	2.45	3.57	5.28	4.11	4.72	4.53	
								Doesn't include a GT start		
Ramp Rate Effect										
-Typical Range X 1.25	-	-	-	-	-	-	-	-	-	-
-C&M cost ($/MW cap.) - Typical Range X 2										
Median	6.40	5.38	4.70	2.13						
~25th_centile	3.66	1.97	2.33	1.19						
~75th_centile	7.35	11.36	9.51	2.68						

Table 4 below presents the updated cost of starts (and stops) and non-cycling baseload VOM costs for the different generation technologies. Figure 12 presents the start cost per megawatt capacity for each of the generation types graphically (median values). As a reminder, these are 2030 projected costs in 2020$.

Table 5 presents the expected increase in EFOR (in added percentage for a single year[14]) due to each cycle type. Baseload or cycling operation both cause forced outages at plants. Cycling operation can accelerate EFOR, especially on a baseload design power plant. Countering the impact on reliability can only be done by replacing or repairing equipment, that is, increased CapEx and OpEx. This is evident in the results of this study. With lower spending, there is a general trend of increased cycling-related reliability impact. Further, in our experience, we know that cycling-related increases in failure rates may not be noted immediately, but critical components will eventually start to fail as the plant accumulates cycling-related damage. Since a vast sample of the units in 2030 will have accumulated several thousand operating hours, the forecasted impact on reliability is valid, and perhaps conservative considering lower O&M spending.

	Coal - Small Sub Critical	Coal - Large Sub Critical	Coal - Super Critical	Gas - Steam	Gas - Large Frame CT	Gas - Aero Derivative CT	Typical CC [GT+HRSG+ST]	High Eff. - CC [GT+HRSG+ST]	Fast Start - CC [GT+HRSG+ST]	Gas - Recip. [per Engine]
Hot	$71	$49	$60	$30	$40	$28	$42	$46	$33	
Warm	$112	$64	$78	$46	$48	$28	$52	$58	$47	
Cold	$144	$114	$126	$67	$57	$28	$75	$84	$72	$10

Figure 12 — Typical Lower Bound Load Following Costs (Median Values).

[14] For example, Table shows a median (lower bound) EFOR impact of 0.0194% per hot start for small sub critical coal units. Assume that the EFOR = 2% for some future year and the Unit typically sees 10 hot starts annually. If 5 additional hot starts are imposed, the EFOR will be raised to 2.097% (2 + 0.00194*5) for a single near-future year.

Table 4 — Projected 2030 Start Cost and Baseload VOM Costs (Lower Bound, 2020$)

Unit Types	Coal - Small Sub Critical	Coal - Large Sub Critical	Coal - Super Critical	Gas - Steam	Gas - Large Frame CT	Gas - Aero Derivative CT	Typical CC [GT+HRSG+ST]	High Eff. - CC [GT+HRSG+ST]	Fast Start - CC [GT+HRSG+ST]	Gas - Recip. [per Engine]
Cost Item/										
Typical Hot Start Data										
-C&M cost ($/MW cap.)										
Median	71	49	60	30	40		42	46	33	
~25th_centile	71	36	43	25	18		32	35	26	
~75th_centile	130	70	77	47	122		82	99	80	
Typical Warm Start Data										
-C&M cost ($/MW cap.)										
Median	112	64	78	46	48		52	58	47	
~25th_centile	94	52	60	34	19		29	32	26	
~75th_centile	211	82	109	91	131		108	139	96	
Typical Cold Start Data										
-C&M cost ($/MW cap.)										
Median	144	114	126	67	57	28	75	84	72	10
~25th_centile	92	66	85	57	20	11	41	46	39	6
~75th_centile	333	159	154	104	138	66	117	157	112	15
Typical Non-cycling Related Costs										
- Baseload Variable Cost ($/MWH)										
Median	1.79	2.40	3.76	0.29	0.56	0.45	2.10	1.80	1.72	0.00
~25th_centile	1.14	1.62	3.15	0.24	0.47	0.18	1.65	1.27	1.30	0.00
~75th_centile	2.70	3.42	4.79	1.74	1.10	0.66	4.42	4.40	4.53	0.00

Table 5 — Projected Impact of Cycling on EFOR

Unit Types	Coal - Small Sub Critical	Coal - Large Sub Critical	Coal - Super Critical	Gas - Steam	Gas - Large Frame CT	Gas - Aero Derivative CT	Typical CC [GT+HRSG+ST]	High Eff. - CC [GT+HRSG+ST]	Fast Start - CC [GT+HRSG+ST]	Gas - Recip. [per Engine]
Cost Item/										
Typical Hot Start Data										
-EFOR Impact										
Median	0.0194%	0.0071%	0.0046%	0.0062%	0.0020%		0.0028%	0.0027%	0.0025%	
~25th_centile	0.0045%	0.0035%	0.0030%	0.0015%	0.0007%		0.0021%	0.0021%	0.0021%	
~75th_centile	0.0495%	0.0164%	0.0130%	0.0285%	0.0145%		0.0081%	0.0084%	0.0070%	
Typical Warm Start Data										
-EFOR Impact										
Median	0.0308%	0.0088%	0.0068%	0.0114%	0.0028%		0.0043%	0.0041%	0.0039%	
~25th_centile	0.0058%	0.0059%	0.0059%	0.0025%	0.0007%		0.0023%	0.0023%	0.0023%	
~75th_centile	0.0624%	0.0390%	0.0390%	0.0308%	0.0165%		0.0095%	0.0205%	0.0186%	
Typical Cold Start Data										
-EFOR Impact										
Median	0.0318%	0.0114%	0.0114%	0.0171%	0.0035%	0.0089%	0.0058%	0.0056%	0.0055%	0.0020%
~25th_centile	0.0085%	0.0047%	0.0060%	0.0041%	0.0007%	0.0036%	0.0033%	0.0033%	0.0033%	0.0011%
~75th_centile	0.0652%	0.0300%	0.0202%	0.0467%	0.0118%	0.0199%	0.0091%	0.0215%	0.0195%	0.0031%

3 | Conclusions

Some of the observations from the figures and tables are as follows:

- There is a large spread of cycling costs as well as reliability impacts.
- On a per megawatt basis, small coal units have the highest cost, while the gas reciprocating engines are the lowest cost. This trend is reflected in terms of the reliability impacts also. Small coal units have the most significant impact while reciprocating engines are designed for flexible operation and hence have the least effect.
- Examining the results published by Intertek AIM in 2012, we estimate the cost of hot and warm starts on conventional steam units (subcritical coal and gas steam units), will be slightly lower in 2030 (results are in 2020$). The drivers for the lower start cost are both the expected increase in the different start types, as well as lower overall spend.
- Small subcritical coal will be subject to increased cycling (lower capacity factors), along with reduced total O&M spend similar to recent trends. This increased cycling, as well as aging, results in significant impact on reliability.
- Larger coal units have similar lower future O&M spend but will likely operate in load following mode with extended shutdowns (cold starts). Therefore, cold start costs increase, while other start costs remain similar or lower to results published in 2012.
- Supercritical coal power plants are operated at baseload and do not cycle on/off much. As these units age and are forced to operate in more flexible mode, the cost of cycling is likely to increase. This will result in slightly lower "baseload VOM" costs compared to historical results. These units cannot easily be brought online under these circumstances and such factors are not fully captured in this dataset. Note that there is a relatively small sample of supercritical coal units in WECC.
- Median cold start cost for each of the generation types is about 1 to 3 times the hot start capital and maintenance cost. For the lower bound 75th percentile, this ratio of cold start cost versus hot start cost is only slightly higher.
- Aeroderivative gas turbines and reciprocating gas engines are designed for flexible operation, and therefore have lower costs. These units also do not get heavily impacted in terms of reliability. In the case of gas turbines, the typical maintenance cycle of the units essentially renews the wear and tear damage. Note that fast starts are deviations to standard start sequence, which may result in increased cycling costs.
- There are some important economies of scale for large steam units that lower their per cycle costs. So, the highest costs per capacity, as shown here, occur in some less efficient or older smaller units, especially for cold starts.
- There is an inherent "tradeoff" relation between higher capital and maintenance expenditure and corresponding lower EFOR.
- Aging effects on conventional combined-cycle units is significant (in 2030). Older units act more like the present coal fleet, while the newer combined-cycle units tend to operate baseload or load following.

- Conventional (older) combined-cycle units were designed for baseload operation and when operated in cycling mode can have higher cycling costs. Similarly, the more efficient, higher temperature gas turbine-based combined-cycle units are also not designed for frequent start/stops. Hence, the cost per cycle of the high efficiency gas combined-cycle units is modestly higher than older combined-cycle units. The fast start combined-cycle units, as expected, are much more economical to operate in on/off mode.
- Reciprocating engines almost always operate as flexible units. The baseload VOM cost for these units is negligible as all the costs are cycling related. These units also do not see much effects on reliability from increased on/off cycles. At low load operation, typically engines on a site may be turned off.
- The coal-fired small and large units were the expensive load following units. As an example, the mill cycle from full load to low load adds significant costs. Emissions control equipment is also affected when units are operated at minimum load for extended hours.
- The combined-cycle units tend to have slightly lower but significant load following costs. This is true because the steam cycle components (i.e., the HRSG, ST, and balance of plant equipment) are impacted by changing operating transients at lower loads. The HRSG is the significant contributor to the cost, though some STs in the industry have been adversely affected by extended low load operation.
- Modest increases in ramp rates during load following results in almost no increase in damage or costs. Doubling accepted ramp rates (subject to design limit or original equipment manufacturer recommendation) is possible on the steam units, though such operation will increase costs. Yet, there might be market mechanisms that allow units to take advantage of the faster ramp rates.
- Aggregating cycling costs at the system level results in ignoring the “flash flood” situation of heavy cycling on individual units on the grid. Transmission expansion studies should include power plant cycling as an input.

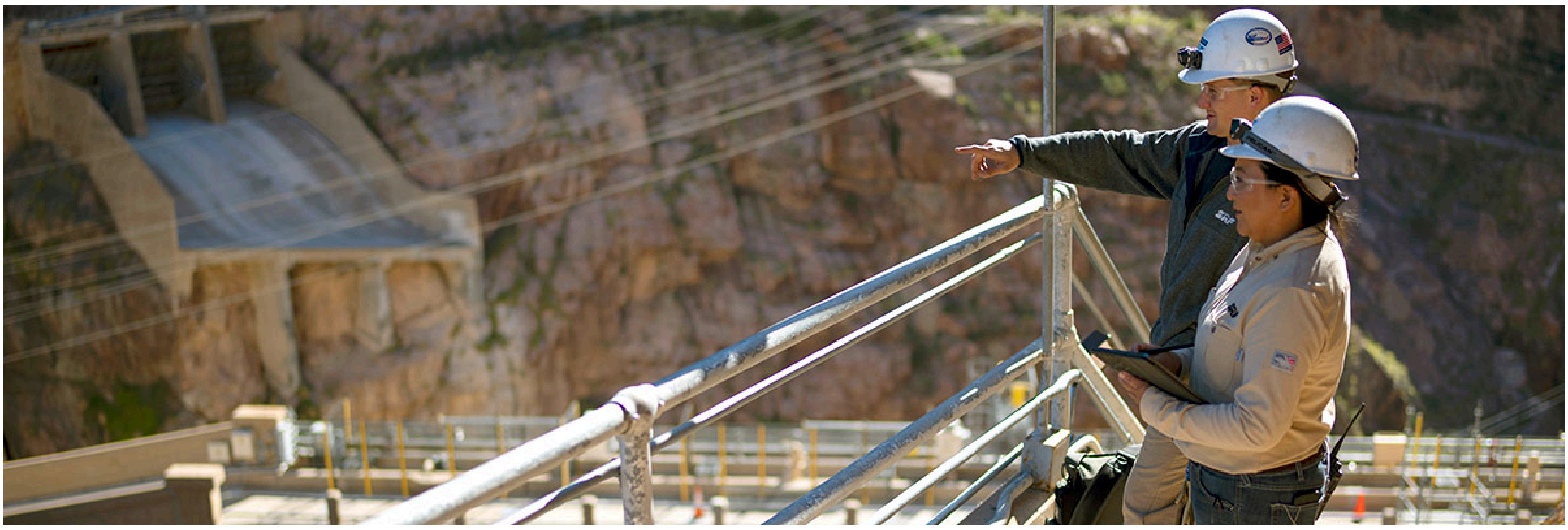
BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Tri-State	)	Order No. 202-25-14
Generation and Transmission	)	
Association, Platte River Power	)	
Authority, Salt River Project,	)	
PacifiCorp, and Xcel Energy	)	

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-60:
SRP Power Generation Sources



SRP power generation sources

SRP is strengthening and preparing the grid for a future that's powered by renewable energy while maintaining the reliability we need to keep your family safe.

On this page:

On related pages:

Santan Generating Station reports & action plans

Coolidge Generating Station reports & action plans

Explore SRP power sources

SRP operates and participates in a number of major power plants and generating facilities in Arizona and around the Southwest. As we add more renewable energy sources to our energy mix, we're strategically using traditional energy sources like natural gas and coal to reliably strengthen our power grid, especially during the hot summer months when energy needs are at their highest.

Explore our diverse energy mix by source or location on the map below.

Filter by Technology

Coronado

Apache County, AZ

Operating Year: 1979

Conventional Steam Coal

Craig (CO)

Moffat County, CO

Operating Year: 1980

Conventional Steam Coal

Davis

Mohave County, AZ

Operating Year: 1951

Conventional Hydropower

Desert Basin

Casa Grande, AZ

Operating Year: 2001

Natural Gas

Dorman Battery

Chandler, AZ

Operating Year: 2018

Battery

Dry Lake Wind

Navajo County, AZ

Operating Year: 2009

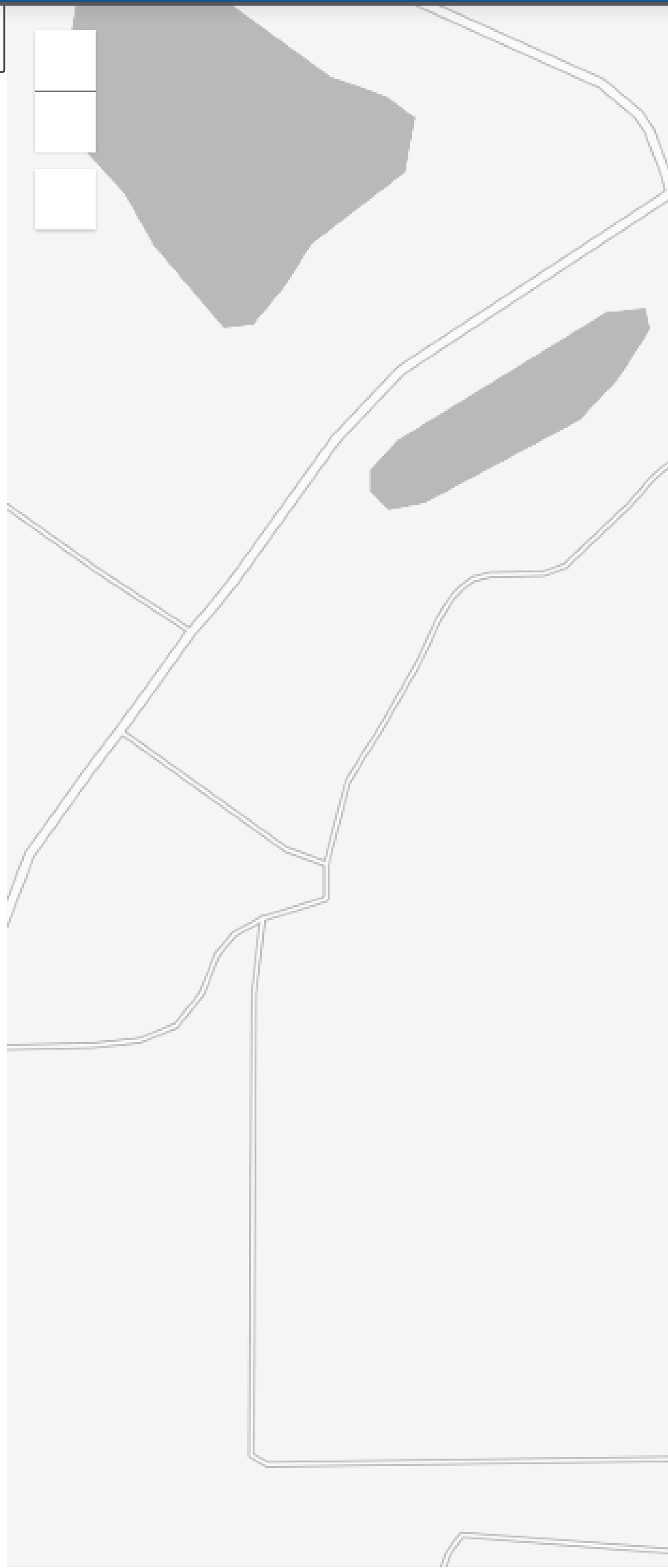
Onshore Wind Turbine

East Line Solar

Coolidge, AZ

Operating Year: 2020

Solar Photovoltaic



Craig (CO): Conventional Steam Coal

Operated by Tri-State Generation and Transmission, SRP owns a share of this three-unit station (29% of Unit 1 and 29% of Unit 2) located in northwestern Colorado. SRP is committed to reducing our carbon emissions, and we are starting to decommission certain coal-fired plants. The plan includes decommissioning Craig Unit 1 in 2025 and Unit 2 in 2028.

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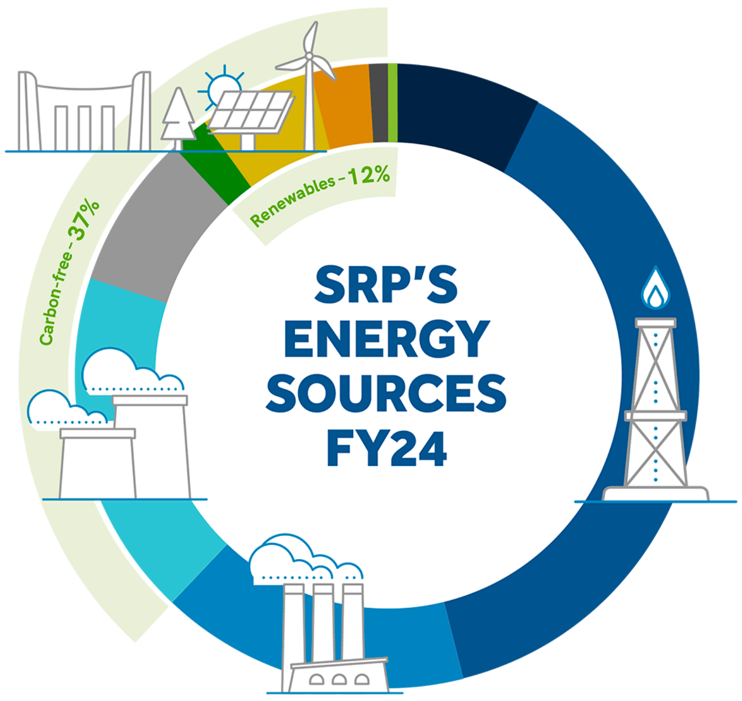
Sustainability at SRP

As part of our commitment to achieve net zero carbon by 2050, we are expanding our mix of clean, renewable energy sources.

Feedback



MARKET – 8%
NATURAL GAS – 38%
COAL – 16%
NUCLEAR – 18%
CUSTOMER PROGRAMS – 8%
HYDRO – 2%
SOLAR – 5%
GEOTHERMAL – 3%
WIND – 1%
BIOMASS – <1%

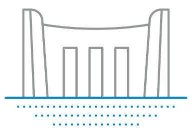
We are committed to net-zero carbon emissions by 2050.

The pie chart shows how the power needs of SRP's retail customers were met during fiscal year 2024 (May 1, 2023-April 30, 2024). This chart represents generation output from all generating facilities operational in FY24. Generation data is pending third-party verification by The Climate Registry.

SRP is committed to cutting carbon emissions intensity by 65% by 2035 and reaching net zero by 2050. Learn more about sustainability at SRP.

Renewables

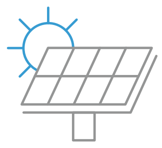
At SRP, we're steadily expanding our energy portfolio to include more power from carbon-free sources.



Hydropower

SRP manages eight dams on the Salt River and Verde River watersheds that provide more than 230 megawatts (MW) of hydropower.

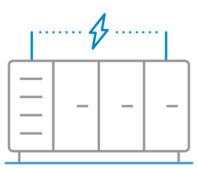
Learn more



Solar

SRP is harnessing the power of America's sunniest city to support a variety of solar solutions for homes and businesses.

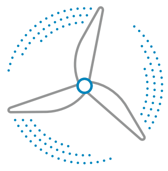
Learn more



Battery storage

SRP uses large-scale battery storage projects to store renewable energy for when it is most needed to support grid reliability.

Learn more



Other renewables

SRP is investing in additional carbon-free resources like wind, geothermal and biomass.

Learn more

SRP generation resources comply with local, state and federal air quality regulations which are protective of human health and the environment. Learn more about our environmental policies and programs.

Technology and innovation

We're continually working to provide reliable, affordable and sustainable power today and for Arizona's future. Check out the stories below to learn how we're innovating today to ensure Arizona continues thriving tomorrow.

Powering the grid with solar

Learn more

Powering carbon neutrality with new energy storage technology

Learn more

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