BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-9

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

Exhibit 41

NERC 2025 Summer Reliability Assessment

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2025 Summer Reliability Assessment

May 2025



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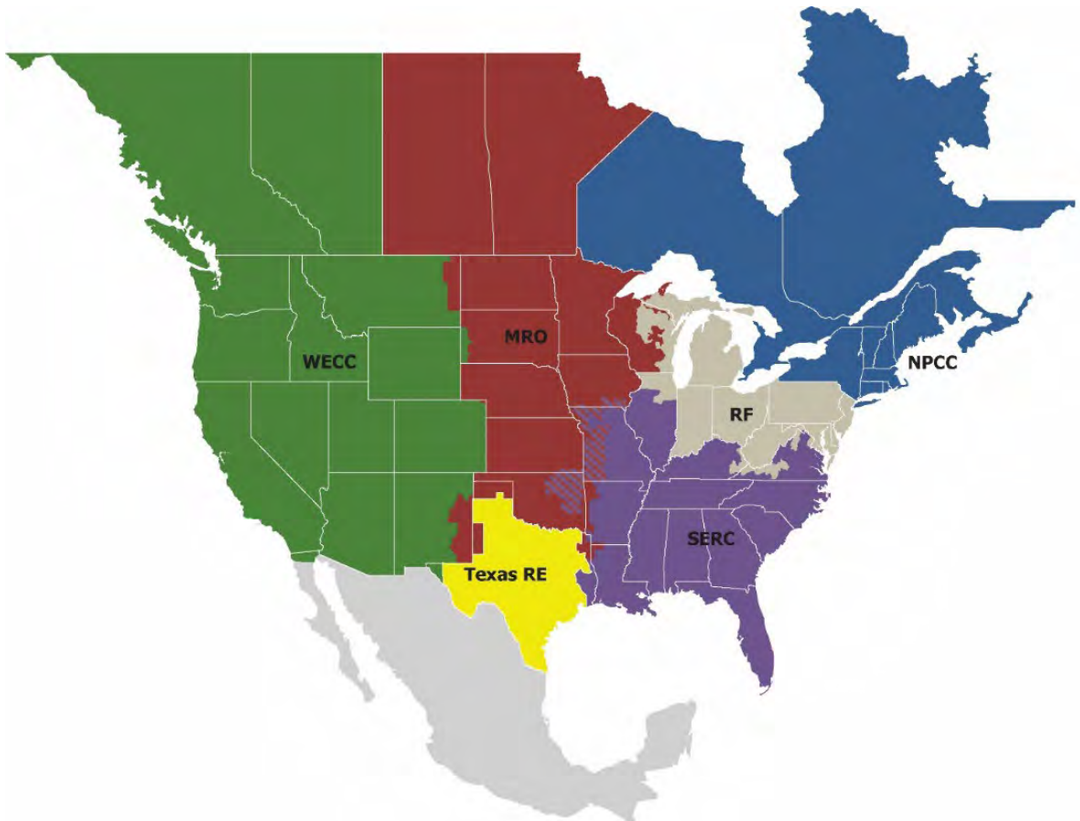
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of NERC and the six Regional Entities, is a highly reliable, resilient, and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is spans six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

About this Assessment

NERC's *2025 Summer Reliability Assessment* (*SRA*) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming summer season. In addition, the *SRA* presents peak electricity demand and supply changes and highlights any unique regional challenges or expected conditions that might affect the reliability of the BPS. The reliability assessment process is a coordinated evaluation between the NERC Reliability Assessment Subcommittee, the Regional Entities, and NERC staff with demand and resource projections obtained from the assessment areas. This report reflects an independent assessment by NERC and the ERO Enterprise and is intended to inform industry leaders, planners, operators, and regulatory bodies so that they are better prepared to take necessary actions to ensure BPS reliability. This report also provides an opportunity for industry to discuss plans and preparations to ensure reliability for the upcoming summer period.

Key Findings

NERC's annual *SRA* covers the upcoming four-month (June–September) summer period. This assessment evaluates generation resource and transmission system adequacy as well as energy sufficiency to meet projected summer peak demands and operating reserves. This includes a deterministic evaluation of data submitted for peak demand hour and peak risk hour as well as results from recently updated probabilistic analyses. Additionally, this assessment identifies potential reliability issues of interest and regional topics of concern. While the scope of this seasonal assessment is focused on the upcoming summer, the key findings are consistent with risks and issues that NERC highlighted in the *2024 Long-Term Reliability Assessment (LTRA*), which covers a 10-year horizon, and other earlier reliability assessments and reports.[1]

Rising electricity demand forecasts, generation growth, and the increasing pace of change in the resource mix feature prominently in the summer risk profile. Since last summer, the aggregate of peak electricity demand for NERC's 23 assessment areas has risen by over 10 GW—more than double the year-to-year increase that occurred between the summers of 2023 and 2024. Over 7.4 GW of generator capacity (nameplate) has retired or become inactive for the upcoming summer, including 2.5 GW of natural-gas-fired and 2.1 GW of coal-fired generators.[2] Meanwhile, growth in solar photovoltaic (PV) and battery storage resources has accelerated with the addition of 30 GW of nameplate solar PV resources and 13 GW of new battery storage. The new solar and battery resource additions are expected to provide over 35 GW in summer on-peak capacity. New wind resources are expected to provide 5 GW on peak. Operators in many parts of the BPS face challenges in meeting higher demand this summer with a resource mix that, in general, has less flexibility and more variability.

The following findings are derived from NERC and the ERO Enterprise's independent evaluation of electricity generation and transmission capacity as well as potential operational concerns that may need to be addressed for Summer 2025.

Resource Adequacy Assessment and Energy Risk Analysis

All areas are assessed as having adequate anticipated resources for normal summer peak load conditions (see **Figure 1**). However, the following areas face risks of electricity supply shortfalls during periods of more extreme summer conditions. This determination of elevated risk is based on analysis of plausible scenarios, including 90/10 demand forecasts and historical high outage rates as well as low wind or solar PV energy conditions:

- **Midcontinent Independent System Operator (MISO):** MISO is expecting to have an existing certain capacity of 142,793 MW in the *2025 SRA*, which is a slight reduction from the 143,866 MW submitted for the *2024 SRA*. The retirement of 1,575 MW of natural gas and coal-fired generation since last summer, combined with a reduction in net firm capacity transfers due to some capacity outside the MISO market opting out of the MISO planning resource auction, is contributing to less dispatchable generation in MISO. With higher demand and less firm resources, MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output. MISO's most recent energy assessment reveals that the period of highest energy shortfall risk has shifted from July to August. This shift is driven by the decline in dispatchable generation and the increasing share that solar and wind resources have in meeting demand. The risk of supply shortfalls increases in late summer as solar output diminishes earlier in the day, leaving variable wind and a more limited amount of dispatchable resources to meet demand.
- **NPCC-New England:** The New England area expects to have sufficient resources to meet the 2025 summer peak demand forecast. As of April 1, the 50/50 peak summer demand is forecast to be 24,803 MW for the weeks beginning June 1, 2025, through September 14, 2025, with a lowest projected net margin of -1,473 MW (6.0%). The lowest projected net margin assumes a net interchange of 1,245 MW, which is capacity-backed; however, ISO New England (ISO-NE) has typically imported around 3,000 MW during summer peak load conditions. ISO-NE anticipates an increase of approximately 500 MW in forced outages from its generating fleet compared to Summer 2024. Based on NPCC's most recent energy assessment, some use of New England's operating procedures for mitigating resource shortages is anticipated during Summer 2025. Cumulative loss of load expectation (LOLE) of <0.031 days/period, loss of load hours (LOLH) of <0.120 hours/period, and expected unserved energy (EUE) of <94 MWh/period were estimated for the expected load with expected summer resources while the reduced resources and highest peak load scenario resulted in an estimated cumulative LOLE risk of 4.369 days/period, with associated LOLH of 19.554 hours/period and EUE of 19,847 MWh/period.
- **MRO-SaskPower:** For the upcoming summer months, no capacity constraints or reliability issues are expected under normal conditions. However, in the event of generator forced outages of more than 350 MW, combined with above-normal peak demand, SaskPower may need to rely on short-term imports from neighboring utilities. Other remedial actions could include quickly activating demand-response programs, adjusting maintenance schedules, and, if necessary, implementing temporary load interruptions. SaskPower's modeling projects

[1] NERC's long-term, seasonal, and special reliability assessments are published on the Reliability Assessments webpage.

[2] Other retirements include 1.2 GW nuclear capacity following the retirement of some units at the Pickering Nuclear Generator Station in Ontario, and 1.6 GW of petroleum, hydro, and other generation. Source: NERC and EIA data.

the probability of experiencing a generation forced outage exceeding 350 MW to be 21.5%. Assuming maximum available imports, the same modeling projects the number of hours with an operating reserve shortfall this summer to be about 0.65 hours with the highest likelihood occurring in June, estimated at 0.43 hours.

- **MRO-SPP:** SPP's Anticipated Reserve Margin (28.5%) is similar to last summer, and resource shortfalls are not expected for the upcoming Summer 2025 season under normal conditions. However, SPP remains at risk for energy shortfalls if above-normal peak demand periods coincide with low wind output and high generator forced outages. Other known operational challenges for the upcoming season include managing wind energy fluctuations; SPP often experiences sharp ramps of its wind generation that can cause transmission system congestion as well as scarcity conditions.
- **Texas RE-ERCOT:** An additional 7 GW of installed solar PV resource capacity and nearly 7.5 GW in new battery storage is helping ERCOT meet rising summer peak demand. ERCOT is projected to have sufficient operating reserves for the August peak load hour given normal summer system conditions. Nevertheless, continued growth in both loads and intermittent renewable resources drives a risk of emergency conditions in the evening hours when solar generation ramps down and loads remain elevated. ERCOT's probabilistic risk assessment of energy emergency alert (EEA) likelihood for the highest risk periods associated with evening hours in the peak month of August is projected to fall to 3%, down from over 15% in 2024. Lower risk is attributed to a nearly doubling of battery energy storage capacity and improved energy availability from new battery storage and operational rules. The South Texas Interconnection reliability operating limit (IROL) continues to present a system constraint, which, under specific unlikely conditions, could ultimately require ERCOT system operators to direct firm load shedding to remain within IROL limits and prevent cascading load loss. For Summer 2025, this risk is being mitigated by updating transmission line dynamic ratings and switching actions to divert power away from the most limiting transmission circuits.
- **WECC-Mexico:** The WECC-Mexico assessment area in Baja California has a peak summer demand of 3,770 MW and is served by a resource mix that is mainly natural-gas-fired generation, with some geothermal, solar, wind, and oil-fired resources (5,636 MW total installed capacity, of which 4,125 MW are gas-fired generators). WECC-Mexico's 14% Anticipated Reserve Margin exceeds the Reference Margin Level for reliability (10%) calculated by WECC. For the upcoming summer, NERC assesses that historically average generator outage rates for peak demand periods can cause a supply shortfall within the WECC-Mexico assessment area and trigger the need for non-firm resources from neighboring areas. Note, in prior SRA reports, the Baja California portion of the BPS was included as part of the WECC-CA/MX assessment area. The *2025 SRA* includes a new assessment area map for the Western Interconnection. The new assessment area boundaries provide reliability risk information in more geographic detail for the United States and Mexico.

Resource additions since last summer have helped lower the risk of energy shortfalls in several areas. Across the U.S. portion of the Western Interconnection, over 6.5 GW of installed solar capacity has been added, along with nearly 7 GW in battery storage. The resources are expected to provide close to 14 GW in on-peak capacity. In British Columbia, new hydroelectric generators were commissioned, contributing to an additional 500 MW in capacity for the summer. The resource additions have alleviated capacity and energy shortfall risks identified in these assessment areas prior to Summer 2024 and provide supplies across the Western Interconnection.

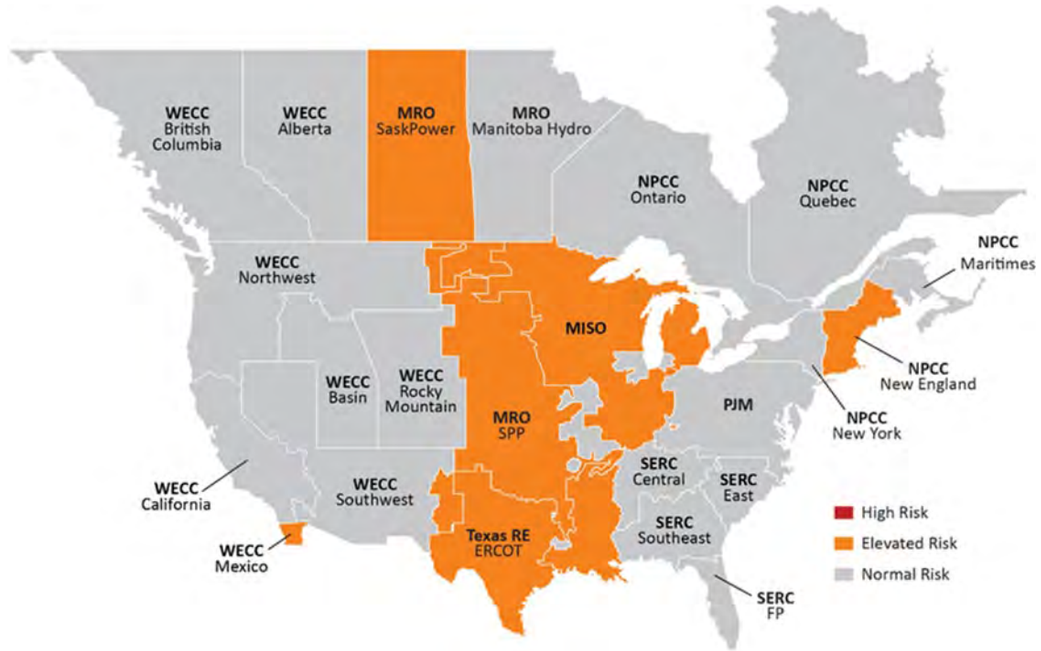


Figure 1: Summer Reliability Risk Area Summary

Seasonal Risk Assessment Summary	
High	Potential for insufficient operating reserves in normal peak conditions
Elevated	Potential for insufficient operating reserves in above-normal conditions
Normal	Sufficient operating reserves expected

Other Reliability Issues

- **Weather services are expecting above-average summer temperatures across much of North America and continued below-average precipitation in the Northwest and Midwest.** In summer-peaking areas, temperature is one of the main drivers of demand and can also contribute to forced outages for generation and other BPS equipment. Average temperatures last summer across the United States and Canada were not as hot as Summer 2023, but Summer 2024 still managed to rank in the top four hottest recorded summers with certain areas breaking records yet again. Few high-level EEAs were issued between June and September 2024, and there were no supply disruptions that resulted from inadequate resources as Balancing Authorities (BA), Transmission Operators (TOP), and Reliability Coordinators (RC) employed a variety of operational mitigations and demand-side management measures. Natural-gas-fired electricity generation broke records last year—highlighting the criticality of natural gas in meeting electric demand. This continuing trend will be key in operator preparations that help to ensure fuel availability for the coming summer. The **Review of 2024 Capacity and Energy Performance** section describes actual demand and resource levels in comparison with NERC's *2024 SRA* and summarizes 2024 resource adequacy events.

- **Load growth is driving higher peak demand forecasts and contributing to resource and transmission adequacy challenges in many areas.** Fifteen of the 23 assessment areas are expecting an increase in peak summer demand from Summer 2024. Aggregated peak demand across all assessment areas has increased by over 10 GW since 2024. This is more than double the increase in peak demand from 2023 to 2024. One of the largest increases is seen in the U.S. West (+5%), where a new peak demand record was set last summer. Extreme heat is reported as a main reliability concern this year among BAs in WECC. With precipitation expected to be lower than average in the Northwest, natural-gas-fired generation and demand-side management could be important in offsetting any lower-than-normal levels of hydroelectric generation availability. SERC Southeast is also projecting a sizable increase in peak demand of more than 2% from NERC's *2024 SRA.* Entities in the assessment area cite economic growth and increased industrial and data mining loads as the main drivers.

- **Aging generation facilities present increased challenges to maintaining generator readiness and resource adequacy.** Forced outage rates for conventional generators and wind resources have trended toward historically high levels in recent years.[3] System operators face increasing risk of resource shortfalls and operating challenges caused by forced generator outages, especially during periods of high demand or when relatively few conventional resources are dispatched to serve load. The threat to BPS reliability can be compounded in areas where aging resources are further depended upon to provide essential reliability services. In the Southwest, for example, a portion of capacity has been in operation for roughly 60 years. Electric utilities in SERC-Central have also described aging generation as a reliability challenge. Historical performance has demonstrated the need for planning assumptions that account for elevated forced outage rates for these generators. Older generators can also require extensive overhauls, such as generator rewinds, that take resources out of service for extended periods of time as discovery work can lead to additional unplanned maintenance.

- **Battery resource additions are helping reduce energy shortfall risks that can arise from resource variability and peaks in demand.** In Texas, California, and across the U.S. West, the influx of battery energy storage systems (BESS) in recent years has markedly improved the ability to manage energy risks during challenging summer periods. These areas can be exposed to energy shortfalls during hours of peak demand and into evening as solar PV output diminishes, but BESS resources that maintain their charge during the day can help meet peak demand and also overcome energy shortfalls on the system that might otherwise occur with solar down-ramps or variability. Natural-gas-fired generation also continues to play an important role in meeting peak demand and flexibly responding to fluctuations output from variable energy resources (VER).

- **Grid operators need to remain vigilant for the potential of inverter-based resources (IBR) to unexpectedly trip during grid disturbances.** While this near-term challenge persists, NERC continues to work diligently with industry to develop long-term solutions to this issue. In April, NERC published the *Aggregated Report on NERC Level 2 Recommendation to Industry: Findings from Inverter-Based Resource Model Quality Deficiencies Alert*.[4] In the report, NERC summarized the deficiencies identified in the Level 2 alert issued in June 2024. The report's findings were as follows:
  - Many grid operators indicated that they did not have the requested data readily available, supporting the previous finding that data acquisition and management was insufficient.
  - Interconnection process requirements are insufficient.
  - Two-thirds of the protection settings used by grid operators are not set to provide the maximum capability. This creates a significant artificial limitation of overall ride-through capability of BPS-connected solar photovoltaic (PV) facilities.
  - 20% of the surveyed facilities use a facility capability with a 0.95 power factor limit, which means that a significant amount of underused reactive capability exists on the BPS.
  - Dynamic model data is inconsistent.

[3] See Key Findings in NERC's 2024 *State of Reliability* report

[4] *Findings from Inverter-Based Resource Model Quality Deficiencies Alert*

As solar, wind, and battery resources remain the predominant types of resources being added to the BPS, it is imperative for industry, vendors, and manufacturers to take the recommended steps for system modeling and study practices and IBR performance.

- **Operators of natural-gas-fired generators should maintain lines of communication with natural gas system operators to support electric grid reliability.** The 2024 summer season was the fourth hottest on record,[5] and natural-gas-fired generation broke records with a peak monthly average in July of 208 TWh, up 4% from July 2023, per the latest data from the Energy Information Administration (EIA). The EIA projects that rising demand for natural gas exports this year in the wake of ramped up liquefied natural gas (LNG) production combined with lower field production levels could tighten natural gas supplies relative to last summer. Amid year-over-year increases in load projections in most assessment areas, this summer could see another record year for natural-gas-fired generation, thereby stretching supplies even further. Given that late spring and early summer are seasons when natural gas system owners and operators typically perform maintenance requiring system outages, vigilance is needed to ensure the reliability of fuel delivery to natural-gas-fired-generators.[6]
- **Supply chain issues continue to affect lead times for Bulk Electric System (BES) equipment maintenance, replacement, and construction.** While no specific reliability issues for the upcoming summer have been identified, Transmission Owners (TO) and Generator Owners (GO) face delays in parts, materials, and skilled technicians. When summer maintenance preparations or installations are delayed, effects on equipment availability can challenge system operators. Over the long term, supply chain issues and uncertainty continue to affect development. Lead times for transformers remain virtually unchanged, averaging 120 weeks in 2024. Large transformer lead times averaged 80–210 weeks.[7]
- **Wildfire risks in the areas that comprise the Western Interconnection remain ever present.** Wildfire conditions can affect transmission operations by prompting preemptive circuit outages to reduce the risk of fire ignition as well as through fire impacts to transmission infrastructure. Transmission system congestion and reduced import capacity can accompany wildfire conditions. Moreover, fires near wind generation result in curtailment for safety reasons, and solar facilities can be susceptible to range fires. Fire damage to transmission lines interconnected to remote hydro sites in the Pacific Northwest can be particularly problematic with restoration typically taking weeks to months to accomplish.

Recommendations

To reduce the risk of electricity shortfalls on the BPS this summer, NERC recommends the following:

- RCs, BAs, and TOPs in the elevated risk areas identified in the key findings should take the following actions:
  - Review seasonal operating plans and protocols for communicating and resolving potential supply shortfalls in anticipation of potentially extreme demand levels.
  - Consider the potential for higher-than-anticipated forced generator outage rates in operating plans due to plant age, operating patterns, or limited pre-seasonal maintenance availability.
  - Employ conservative generation and transmission outage coordination procedures and operate conservatively commensurate with long-range weather forecasts to ensure adequate resource availability. The review of system performance during the January 2025 cold weather event noted that early declaration of conservative operations in advance of extreme conditions helped reduce grid congestion and enhance transfer capability.[8]
  - Engage state or provincial regulators and policymakers to prepare for efficient implementation of demand-side management mechanisms called for in operating plans.
- GOs with solar PV resources should implement recommendations in the IBR performance issues alert that NERC issued in March 2023.[9]
- State regulators and industry should have protocols in place at the start of summer for managing emergent requests from generators for air-quality restriction waivers. If warranted, U.S. Department Energy (DOE) action to exercise emergency authority under the Federal Power Act (FPA) section 202(c) may be needed to ensure that sufficient generation is available during extreme weather conditions.

[5] US sweltered through its 4th-hottest summer on record – National Oceanic and Atmospheric Administration
[6] Short-Term Energy Outlook - U.S. Energy Information Administration (EIA)
[7] Supply shortages and an inflexible market give rise to high power transformer lead times | Wood Mackenzie
[8] See notable operations practices in Appendix 2 of the *January 2025 Arctic Events System Performance Review | FERC, NERC, and its Regional Entities: A Joint Staff Report*, April 2025.
[9] See NERC Level 2 Alert: Inverter-Based Resource Performance Issues, March, 2023. Owners and operators of BPS-connected IBRs that are currently not registered with NERC should consult NERC's IBR Registration Initiative for information on the registration process.

Summer Temperature and Drought Forecasts

During the summer season, heat drives peak electricity demand as consumers use more electricity to cool their homes and businesses. Summer 2024 was the fourth hottest summer on record for the United States and Canada, and Summer 2025 is expected to bring similar intensity. Assessment area load forecasts account for many years of historical demand data, often up to 30 years, to predict summer peak demand and prepare for more extreme conditions. According to their probabilistic assessments of the coming summer season, late July and early August are the periods most frequently identified among the assessment areas as the expected period of peak demand. Peak demand hours may not coincide with the highest risk hours in the summer as the resource mix shifts during a 24-hour cycle, particularly when there are prolonged periods of above-normal temperatures. Coordinating pre-season preparations and maintenance remains critical to avoiding forced outages where possible and mitigating risks to BPS reliability.

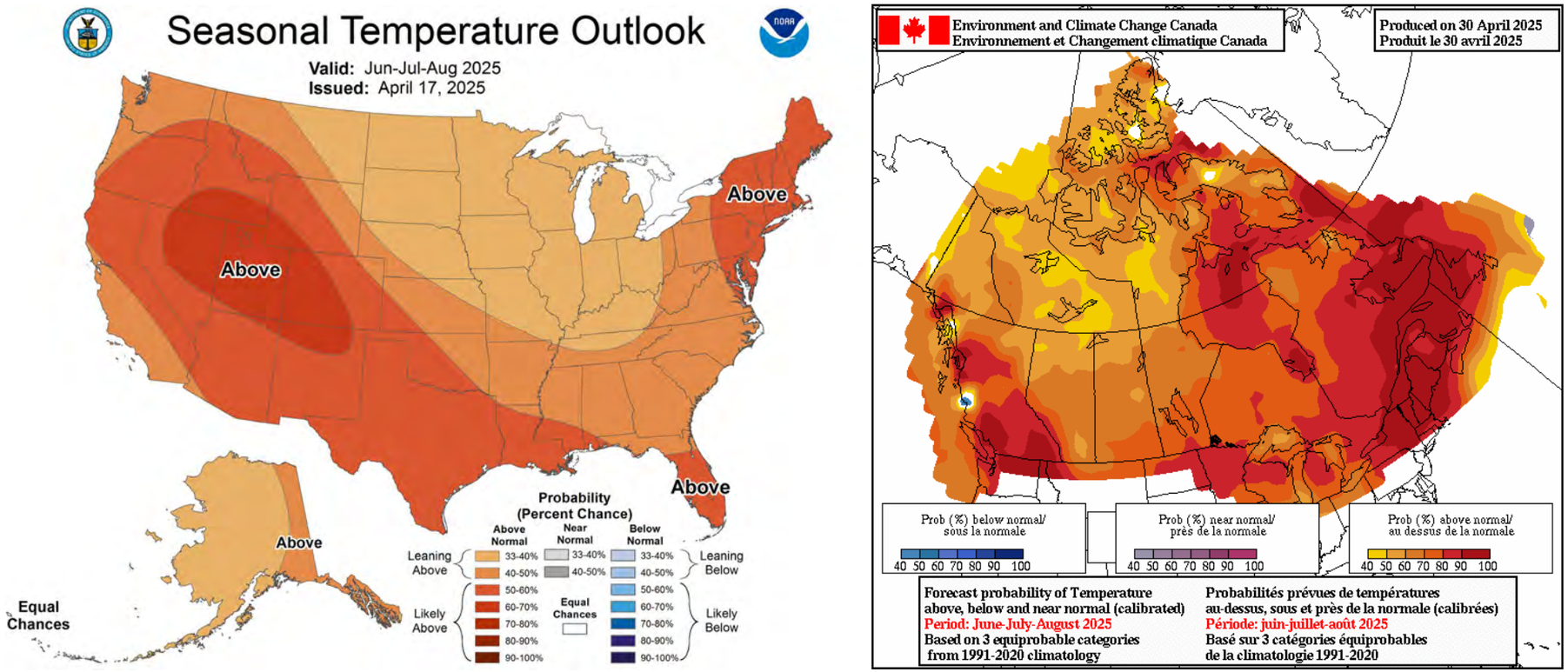


Figure 2: United States and Canada Summer Temperature Outlook[10]

[10] Seasonal forecasts obtained from U.S. National Weather Service and Natural Resources Canada: https://www.cpc.ncep.noaa.gov/products/predictions/long_range/ and https://weather.gc.ca/saisons/prob_e.html

Risk Assessment Discussion

NERC assesses the risk of electricity supply shortfall in each assessment area for the upcoming season by considering Planning Reserve Margins, seasonal risk scenarios, probability-based risk assessments, and other available risk information. NERC provides an independent assessment of the potential for each assessment area to have sufficient operating reserves under normal conditions as well as above-normal demand and low-resource output conditions selected for the assessment. A summary of the assessment approach is provided in Table 1.

Table 1: Seasonal Risk Assessment Summary

Category	Criteria[1]
High Potential for insufficient operating reserves in normal peak conditions	• Planning Reserve Margins do not meet Reference Margin Levels • Probabilistic indices exceed benchmarks (e.g., LOLH of 2.4 hours over the season) • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **normal peak-day demand and outage scenarios**[2]
Elevated Potential for insufficient operating reserves in above-normal conditions	• Probabilistic indices are low but not negligible (e.g., LOLH above 0.1 hours over the season) • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **extreme peak-day demand with normal resource scenarios** (i.e., typical or expected outage and derate scenarios for conditions)[2] • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **normal peak-day demand with reduced resources** (i.e., extreme outage and derate scenarios)[3]
Normal Sufficient operating reserves expected	• Probabilistic indices are negligible • Analysis of the risk hour(s) indicates resources will be sufficient to meet operating reserves under normal and extreme peak-day demand and outage scenarios[4]

Table Notes:
[1]The table provides general criteria. Other factors may influence a higher or lower risk assessment.
[2]**Normal resource scenarios** include planned and typical forced outages as well as outages and derates that are closely correlated to the extreme peak demand.
[3]**Reduced resource scenarios** include planned and typical forced outages and low-likelihood resource scenarios, such as extreme low-wind scenarios, low-hydro scenarios during drought years, or high thermal outages when such a scenario is warranted.
[4]Even in normal risk assessment areas, extreme demand and extreme outage scenarios that are not closely linked may indicate risk of operating reserve shortfall.

Assessment of Planning Reserve Margins and Operational Risk Analysis

Anticipated Reserve Margins, which provide the Planning Reserve Margins for normal peak conditions, as well as reserve margins for seasonal risk scenarios of more extreme conditions are provided in Table 2.

Table 2: Seasonal Risk Scenario On-Peak Reserve Margins

Assessment Area	Anticipated Reserve Margin	Anticipated Reserve Margin with Typical Outages	Anticipated Reserve Margin with Higher Demand, Outages, Derates in Extreme Conditions
MISO	24.7%	9.3%	-1.9%
MRO-Manitoba	14.6%	11.2%	3.8%
MRO-SaskPower	33.5%	28.3%	22.4%
MRO-SPP	28.5%	18.2%	3.4%
NPCC-Maritimes	42.2%	31.7%	18.6%
NPCC-New England	14.1%	3.9%	4.0%
NPCC-New York	31.6%	12.5%	5.2%
NPCC-Ontario	23.4%	23.4%	3.7%
NPCC-Québec	32.7%	28.2%	19.1%
PJM	24.7%	15.0%	5.3%
SERC-C	19.6%	12.7%	3.2%
SERC-E	29.1%	21.8%	13.0%
SERC-FP	20.2%	14.0%	11.8%
SERC-SE	41.3%	37.7%	12.5%
TRE-ERCOT	43.2%	33.0%	-5.1%
WECC-AB	42.6%	40.3%	20.5%
WECC-Basin	24.3%	15.9%	-27.2%
WECC-BC	24.3%	24.2%	-6.6%
WECC-CA	56.9%	51.0%	4.7%
WECC-Mex	14.1%	1.6%	-16.8%
WECC-NW	32.1%	29.4%	-13.0%
WECC-RM	25.7%	18.2%	-18.9%
WECC-SW	22.3%	14.0%	-13.0%

Seasonal risk scenarios for each assessment area are presented in the **Regional Assessments Dashboards** section. The on-peak reserve margin and seasonal risk scenario charts in each dashboard provide potential summer peak demand and resource condition information. The reserve margins on the right side of the dashboard pages provide a comparison to the previous year's assessment. The seasonal risk scenario charts present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. The assessment areas determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized in the seasonal risk scenario charts; more information about these dashboard charts is provided in the **Data Concepts and Assumptions** section.

The seasonal risk scenario charts can be expressed in terms of reserve margins: In **Table 2**, each assessment area's Anticipated Reserve Margins are shown alongside the reserve margins for a typical generation outage scenario (where applicable) and the extreme demand and resource conditions in their seasonal risk scenario.

Highlighted in **orange** are the areas identified as having resource adequacy or energy risks for the summer in the **Key Findings** section. The typical outage reserve margin includes anticipated resources minus the capacity that is likely to be in maintenance or forced outage at peak demand. If the typical maintenance or forced outage margin is the same as the Anticipated Reserve Margin, it is because an assessment area has already factored typical outages into the anticipated resources. The extreme conditions margin includes all components of the scenario and represents the most severe operating conditions of an area's scenario. Note that any reserve margin below zero indicates that the resources fall below demand in the scenario.

In addition to the peak demand and seasonal risk hour scenario charts, the assessment areas provided a resource adequacy risk assessment that was probability-based for the summer season. Results are summarized in **Table 3**. The risk assessments account for the hour(s) of greatest risk of resource shortfall. For most areas, the hour(s) of risk coincides with the time of forecasted peak demand; however, some areas incur the greatest risk at other times based on the varying demand and resource profiles. Various risk metrics are provided and include LOLE, LOLH, EUE, and the probabilities of an EEA occurrence.

Energy Emergency Alerts

Extreme generation outages, low resource output, and peak loads similar to those experienced in wide-area heat events and the heat domes experienced in western parts of North America during the last three summers are ongoing reliability risks in certain areas for Summer 2025. When forecasted resources in an area fall below expected demand and operating reserve requirements, BAs may need to employ operating mitigations or EEAs to obtain the capacity and energy necessary for reliability. A description of each EEA level is provided below.

Energy Emergency Alert Levels

EEA Level	Description	Circumstances
EEA1	All available generation resources in use	• The BA is experiencing conditions in which all available generation resources are committed to meet firm load, firm transactions, and reserve commitments and is concerned about sustaining its required contingency reserves. • Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
EEA2	Load management procedures in effect	• The BA is no longer able to provide its expected energy requirements and is an energy-deficient BA. • An energy-deficient BA has implemented its operating plan(s) to mitigate emergencies. • An energy-deficient BA is still able to maintain minimum contingency reserve requirements.
EEA3	Firm load interruption is imminent or in progress	• The energy-deficient BA is unable to meet minimum contingency reserve requirements.

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
MISO	The Planning Year 2025–2026 LOLE Study Report, an annual LOLE probabilistic study[11]	The values for LOLH and EUE are taken from the assessment report noted, where the annual LOLE is set at 1 day in 10 years, or 0.1 LOLE for the summer season. For Summer 2025, LOLH is 0.252 hrs/year and EUE is 626.2 MWH/year for the Reference Margin Level. Expectations for load-loss and unserved energy are less than these amounts because MISO's resources are above the Reference Margin Level.
MRO-Manitoba	The 2024 LOLE Study	Manitoba Hydro's probability-based resource adequacy risk assessment for the summer (June–September) season is that there is a low risk of resource adequacy issues. The study indicated Annual Probabilistic Indices for the Manitoba Hydro system for 2026 of 5 MWh per year of EUE, considering a range of flow conditions, and that all of this risk would be in the higher load winter season. The increases in Manitoba load since the 2022 LOLE Study were more than offset by a reduction in long-term exports contract with the expiration of a major export sale in April 2025.
MRO-SaskPower	Probability-based capacity adequacy assessment Summer 2025	According to the study, SaskPower's expected number of hours with an operating reserve shortfall between June and September is about 0.65 hours, assuming maximum available imports. June has the highest likelihood of an EEA, estimated at 0.43 hours. For Summer 2025, the projected probability of experiencing a generation forced outage exceeding 350 MW stands at 21.5%. This number represents an approximation of the likelihood, during any given hour of the summer period, of encountering a generation forced outage surpassing the 350 MW threshold.
MRO-SPP	2024 NERC *LTRA* with Probabilistic Assessment (ProbA)	With the current SPP fleet, the ProbA base case Year 2 produced no LOLE.
NPCC	NPCC conducted an all-hour probabilistic assessment that consisted of a base case and several more severe scenarios examining low resources, reduced imports, and higher loads. The highest peak load scenario has a 7% probability of occurring.	NPCC Regional Entity assesses that there will be an adequate supply of electricity across the Regional Entity this summer. Necessary strategies and procedures are in place to deal with operational challenges and emergencies as they may develop. Preliminary results of the probabilistic analysis by assessment area are below. NPCC anticipates releasing the assessment in May.
NPCC-Maritimes		NPCC's assessment results indicate that Maritimes expects minimal LOLE, LOLH, and EUE over the May–September period, with the highest risk occurring in July and August. The assessment projected LOLE at less than 0.089 days per period, LOLH at less than 0.4 hours per period, and EUE at less than 16.5 MWh per period under the reduced resources and highest peak demand scenario.
NPCC-New England		Based on NPCC's assessment, cumulative LOLE (<0.031 days/period), LOLH (<0.120 hours/period), and EUE (<94 MWh/period) risks were estimated over the summer May to September period for the expected load with expected resources scenario. The highest peak load level conditions with reduced resources scenario resulted in an estimated cumulative LOLE risk (4.369 days/period), with associated LOLH (19.554 hours/period) and EUE (19,847 MWh/period) with the highest risk occurring in June, with some in July and August.
NPCC-New York		Negligible cumulative LOLE (<0.018 days/period), LOLH (<0.054 hours/period), and EUE (33 MWh/period) risks were estimated over the summer May–September period for the expected load with expected resources for the summer. For highest peak load level with low likelihood, reduced resource conditions resulted in an estimated cumulative LOLE risk (1.7 days/period), with associated LOLH (6.5 hours/period) and EUE (4,860 MWh/period) with the highest risk occurring in July and August.

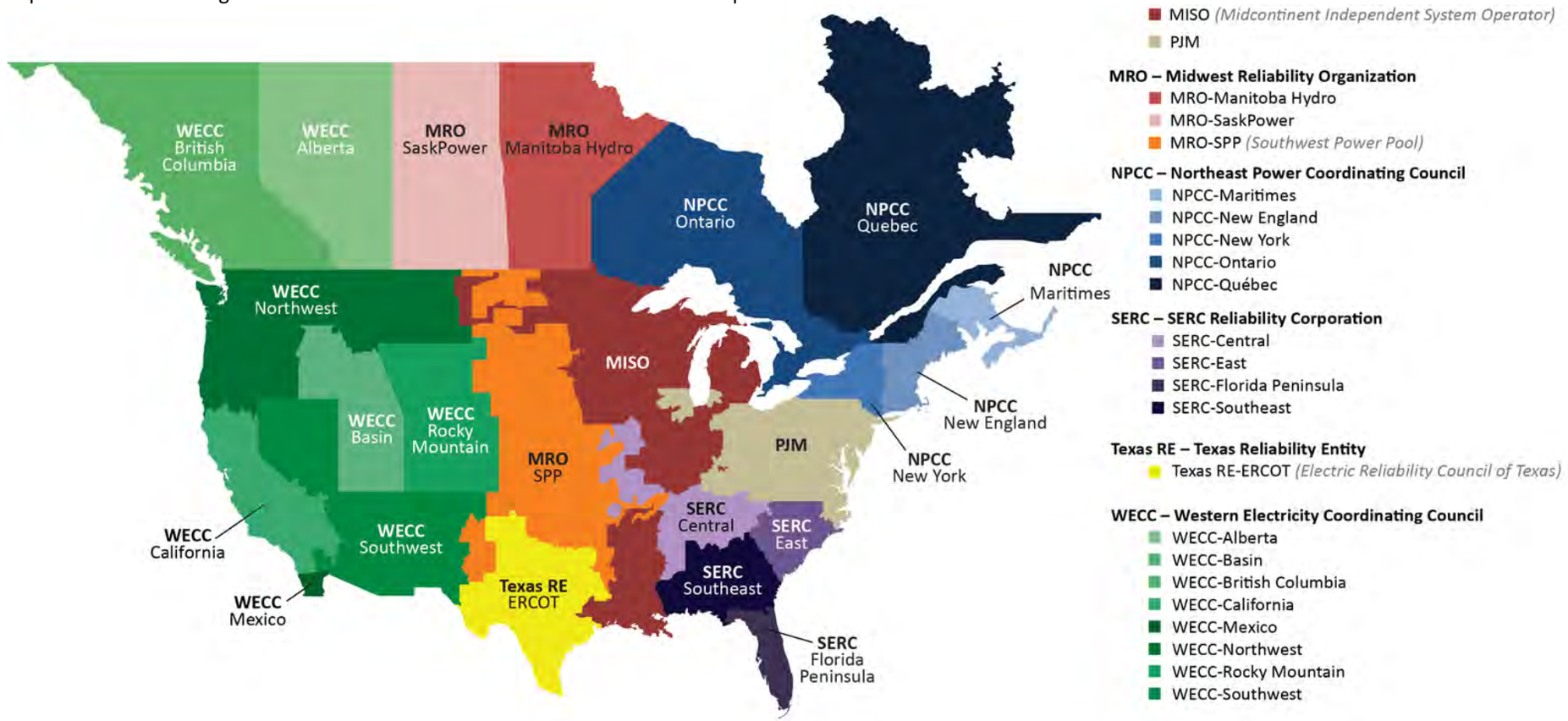
[11] PY 2025–2026 LOLE Study Report

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
NPCC-Ontario		NPCC's preliminary result of this assessment indicates that the low-likelihood resource case, highest peak load level conditions resulted in a negligible cumulative LOLE (0.081 days/period), with associated cumulative LOLH (0.212 hours/period) and EUE (145.4 MWh/period) with the highest risks occurring predominantly in July, with some in August. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the May–September summer period for the other scenarios modeled.
NPCC-Québec		The Québec assessment area is not expected to require use of their operating procedures designed to mitigate resource shortages during Summer 2025. Québec did not demonstrate any measurable amounts of cumulative LOLE, LOLH, or EUE risks over the May–September summer period for all the scenarios modeled since the system is winter peaking.
PJM	2023 PJM Reserve Requirement Study (RRS)	PJM is expecting a low risk of resources falling below required operating reserves during Summer 2025. PJM is forecasting around 27% installed reserves (including expected committed demand resources), which is above the target installed reserve margin of 17.7% necessary to meet the 1-day-in-10-years LOLE criterion. The Reserve Requirement Study analyzed a wide range of load scenarios (low, regular, and extreme) as well as multiple scenarios for system-wide unavailable capacity due to forced outages, maintenance outages, and ambient derations. Due to the rather low penetration of limited and variable resources in PJM relative to PJM's peak load, the hour with the most loss-of-load risk remains the hour with the highest forecasted demand.
SERC-Central SERC-East SERC-Florida Peninsula SERC-Southeast	2024 NERC *LTRA* with ProbA. For the ProbA, SERC evaluates 8,760 hourly load and 1,900 sequential Monte Carlo simulations. The results are a probability weighted average of cases, including 38 historic weather-years that are applied to load forecasts for years 2026 and 2028. The model applies a range of economic load forecast errors from -4% to 4% and other noted assumptions.	The 2024 ProbA indicates some resource adequacy risk to SERC with the results for the year 2028 showing slightly higher risk than the year 2026. For the entire SERC footprint, Summer 2026 shows a low risk in summer afternoons into evenings, and for Summer 2028, that risk is still low but extends from summer evenings later into summer nights.
Texas RE-ERCOT	ERCOT probabilistic assessment using the Probabilistic Reserve Risk Model	The simulation indicates some risk of having to declare an EEA for hours ending 20 and 21 for the peak load day in August. These two hours have the highest EEA risk (reflecting corresponding high net load conditions) with probabilities of declaring an EEA 3.05% and 1.54%, respectively. This is categorized by ERCOT as "Low risk" per its criteria of hourly EEA probability that is equal to or less than 10%. For the *2024 SRA*, ERCOT reported EEA declaration probabilities for hours ending 20 and 21 of 18.4% and 9.2%, respectively. The large decrease in EEA probabilities is due to the addition of 7,414 MW of BESS capacity.
WECC	2024 Western Assessment on Resource Adequacy employs a probabilistic energy, area-wide assessment, using Multi Area Variable Resource Integration Convolution (MAVRIC) model	

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
WECC-AB		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. All resource margins have increased since last summer with the addition of new capacity, including almost 2,700 MW of new natural gas capacity, 1,200 MW of new wind (+27%), 200 MW of new solar (+13%), and 54 MW of new energy storage systems (+27.5%) on-line. The peak hour has moved earlier, to 3:00 p.m. from 4:00 p.m., still in late July.
WECC-Basin		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The reserve margins are not anticipated to fall below the reference margin (14%) for the upcoming summer—existing-certain is forecast at 19% with anticipated and prospective at 24%. The area is expected to peak in early July around 3:00 p.m.
WECC-BC		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The reserve margins are not anticipated to fall below the reference margin for the upcoming summer. All reserve margins have increased since 2024 due to increased capacity and energy availability. The peak hour for summer is forecast for early August around 4 p.m.
WECC-CA		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The reserve margins are not anticipated to fall below the reference margin for the upcoming summer. Reserve margins have increased since last summer with the increased existing-certain and Tier 1 planned capacity more than offsetting the decrease in available demand response.
WECC-Mex		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The peak hour is expected to occur in early August around 4:00 p.m. The reserve margins (14%) are not anticipated to fall below the reference margin (10%) for the upcoming summer. An extreme summer peak load is anticipated to be 4,067 MW. Under extreme conditions, typical forced outages are expected to be 472 MW and derates for thermal generation resources are expected to be 330 MW, requiring imports from neighboring areas. The expected operating reserve requirement on peak is 226 MW.
WECC-RM		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The peak hour is expected to occur in late July around 4:00 p.m. Summer 2025 reserve margins (existing-certain 25%, and anticipated and prospective 26%) are not anticipated to fall below the reference margin (17%). An extreme summer peak load may be around 15 GW, and the area has 17.3 GW of existing-certain capacity plus 104 MW of planned new resources. Typical forced outages could be 1,044 MW and derates under extreme conditions of 1,561 MW for thermal and 990 MW for wind. The expected operating reserve requirement on peak is 846 MW.
WECC-NW		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. Summer 2025 peak hour is expected to occur in early July around 5:00 p.m. Reserve margins (existing-certain 29% and anticipated and prospective 32%) are not anticipated to fall below the reference margin (23%). An extreme summer peak load may be around 32,740 MW. Typical forced outages are forecast to be 777 MW with derates for thermal under extreme conditions to be 1,584 MW and 2,649 MW for wind. The expected operating reserve requirement on peak is 1,750 MW.
WECC-SW		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The peak hour is expected to occur in early July around 5:00 p.m. The existing-certain 17% reserve margin does not fall below the reference margin (13%) for the upcoming summer. The anticipated and prospective reserve margin rises to 22%. An extreme summer peak load could approach 40 GW during the riskiest hour, while the region is anticipated to have 40.3 GW of existing-certain energy available and an additional 2 GW of Tier 1 planned resources. Typical forced outages are estimated near 3 GW, and derates for thermal under extreme conditions can shave another 3 GW from available energy. The expected operating reserve requirement is 2,119 MW.

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six Regional Entities on an assessment area basis. Guidelines and definitions are in the **Data Concepts and Assumptions** table. On-peak reserve margin bar charts show the Anticipated Reserve Margin compared to a Reference Margin Level that is established for the areas to meet resource adequacy criteria. Prospective Reserve Margins can give an indication of additional on-peak capacity but are not used for assessing adequacy. The operational risk analysis shown in the following regional assessments dashboard pages provides a deterministic scenario for understanding how various factors that affect resources and demand can combine to impact overall resource adequacy. For each assessment area, there is a risk-period scenario graphic; the left **blue** column shows anticipated resources (from the **Demand and Resource Tables**), and the **orange** column at the right shows the two demand scenarios of the normal peak net internal demand (from the **Demand and Resource Tables**) and the extreme summer peak demand determined by the assessment area. The middle **red** or **green** bars show adjustments that are applied cumulatively to the anticipated resources. Adjustments may include reductions for typical generation outages (maintenance and forced not already accounted for in anticipated resources) and additions that represent the quantified capacity from operational tools (if any) that are available during scarcity conditions but have not been accounted for in the *SRA* reserve margins. Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The cumulative effects from extreme events are also factored in through additional resource derates or low-output scenarios. In addition, results from a probability-based resource adequacy assessment are shown in the Highlights section of each dashboard. Methods varied by assessment area and provided further insights into the risk conditions forecasted for the summer period.





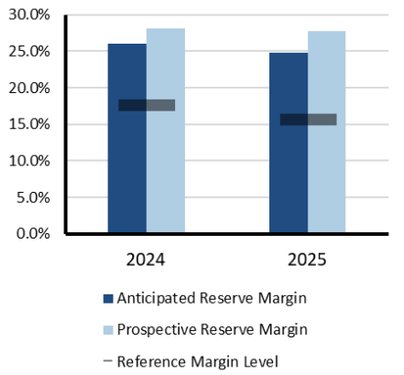
MISO

MISO is a not-for profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency. MISO manages energy, reliability, and operating reserve markets that consist of 36 local BA and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three Regional Entities, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

Highlights

- Demand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output.
- The performance of wind and solar generators during periods of high electricity demand is a key factor in determining whether system operators need to employ operating mitigations, such as maximum generation declarations and energy emergencies; MISO has over 31,000 MW of installed wind capacity and 18,245 MW of installed solar capacity; however, the historically based on-peak capacity contribution is 5,616 MW and 9,123 MW, respectively.
- Since last summer, over 1,400 MW of thermal generating capacity has been retired in MISO, and the new generation that has been added is predominantly solar (8,080 MW nameplate/4,140 MW on-peak).
- MISO's most recent energy assessment reveals that the period of highest energy shortfall risk has shifted from July to August.

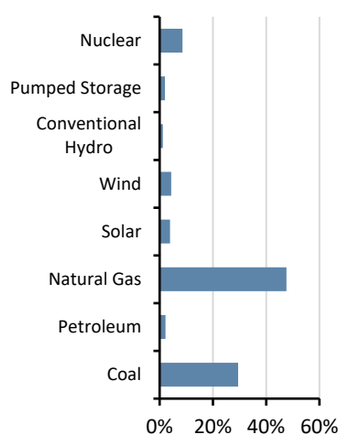
On-Peak Reserve Margin



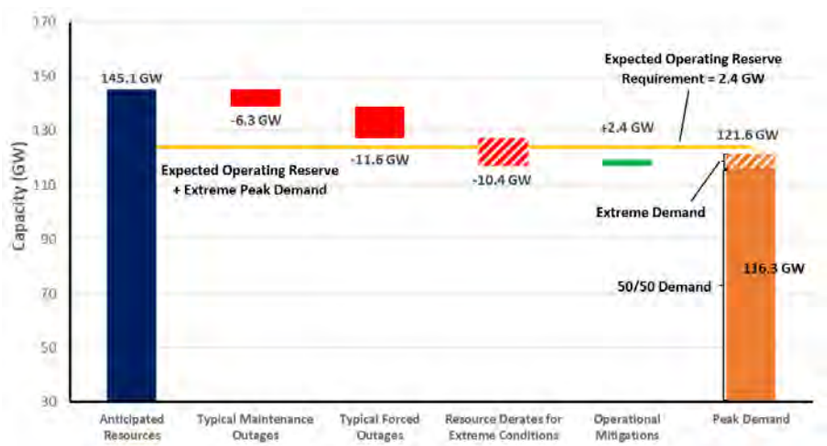
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and extreme generator outage conditions could result in the need to employ operating mitigations (e.g., load-modifying resources and energy transfers from neighboring systems) and EEAs. Emergency declarations that can only be called upon when available generation is at maximum capability are necessary to access load-modifying resources (demand response) when operating reserve shortfalls are projected.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

Maintenance Outages: Rolling five-year summer average of maintenance and planned outages

Forced Outages: Five-year average of all outages that were not planned

Extreme Derates: Maximum historical generation outages

Operational Mitigations: A total of 2.4 GW capacity resources available during extreme operating conditions



MRO-Manitoba Hydro

Manitoba Hydro is a provincial Crown corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro is a leader in providing renewable energy and clean-burning natural gas. Manitoba Hydro provides electricity to approximately 608,500 electric customers in Manitoba and natural gas to approximately 293,000 customers in southern Manitoba. Its service area is the province of Manitoba, which is 251,000 square miles. Manitoba Hydro is winter peaking. Manitoba Hydro is its own Planning Coordinator (PC) and BA. Manitoba Hydro is a coordinating member of MISO, which is the RC for Manitoba Hydro.

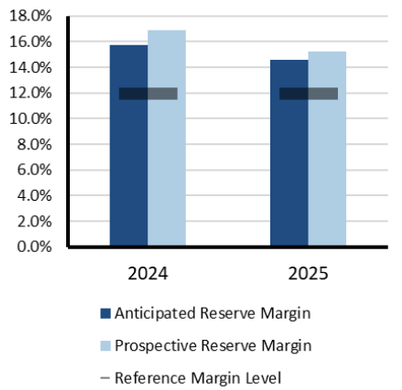
Highlights

- Manitoba Hydro is not anticipating any operational challenges and/or emerging reliability issues in its assessment area for Summer 2025; the Anticipated Reserve Margin for Summer 2025 exceeds the 12% Reference Margin Level.
- While Manitoba Hydro experienced demand growth in the past year, the growth is less than the recent reduction in firm export contracts.
- Manitoba Hydro water supply conditions are below average but improved from this time last year, and above-average winter snowfall will favorably impact spring runoff.
- Manitoba Hydro expects to reliably supply its internal demand and export obligations even if extreme drought develops throughout the year.

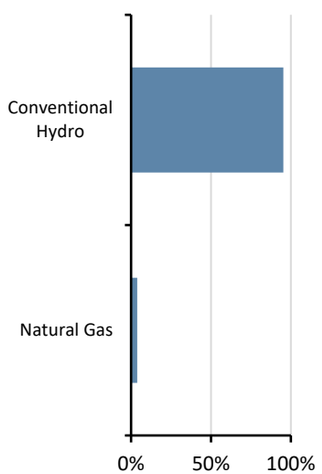
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

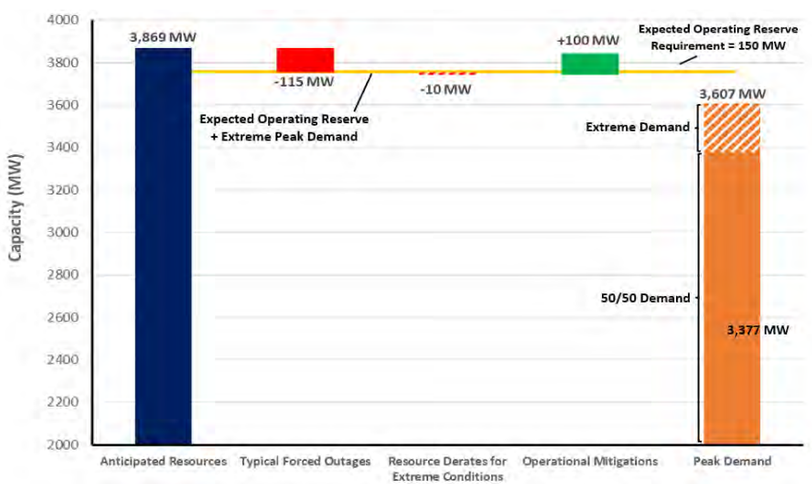
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: (50/50) Demand with allowance for extreme demand based on extreme summer weather scenario of 35.4 C (96 F)

Forced Outages: Typical forced outages

Extreme Derates: Summer wind capacity accreditation of 18.1% of nameplate rating based on MISO seasonal analysis

Normal hydro generation expected for this summer.

Operational Mitigations: Utilize Curtailable Rate Program to manage peak demand; utilize operating reserve if additional measures required



MRO-SaskPower

MRO-SaskPower is an assessment area in the Saskatchewan province of Canada. The province has a geographic area of 651,900 square kilometers (251,700 square miles) and a population of approximately 1.1 million. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the PC and RC for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial Crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan BES and its Interconnections.

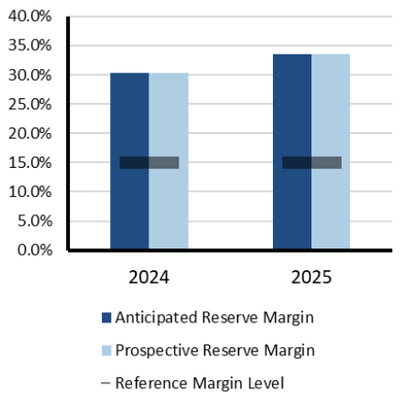
Highlights

- Although Saskatchewan is mainly a winter-peaking region, summer can also bring high electricity demand due to extreme heat.
- Each year, SaskPower works with Manitoba Hydro on a joint summer operating study with input from the Western Area Power Administration and Basin Electric to develop operational guidelines to address any potential challenges.
- The expected number of hours with an operating reserve shortfall between June and September is about 0.65 hours, assuming maximum available imports. The risk of shortfall increases if major unplanned generator outages coincide with scheduled maintenance during peak demand months (June to September). For Summer 2025, the projected probability of experiencing a generation forced outage exceeding 350 MW stands at 21.5%. This number represents an approximation of the likelihood of encountering a generation forced outage surpassing the 350 MW threshold during any given hour of the summer period.
- If extreme heat coincides with significant generation outages, SaskPower will act by activating demand-response programs, arranging short-term power imports from neighboring utilities, and, if necessary, implementing temporary load interruptions to maintain grid stability.

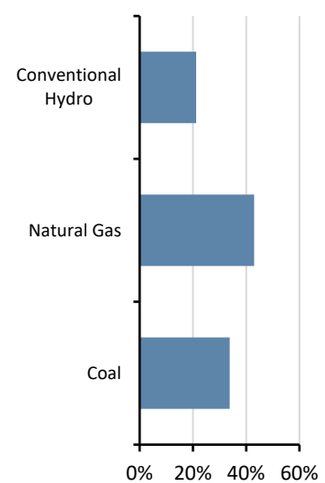
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand and outage conditions. Above-normal summer peak load and outage conditions are likely to result in the need to employ operating mitigations (e.g., demand response and transfers) and EEAs.

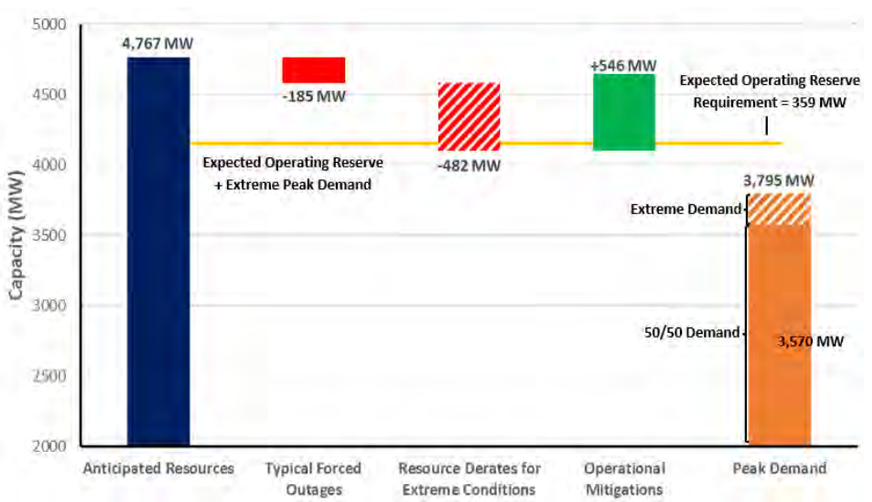
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and above-normal scenario based on peak demand with lighting and all consumer loads

Forced Outages: Estimated by using SaskPower forced outage model

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: Estimated non-firm imports and standby generators on 2–7-day notice



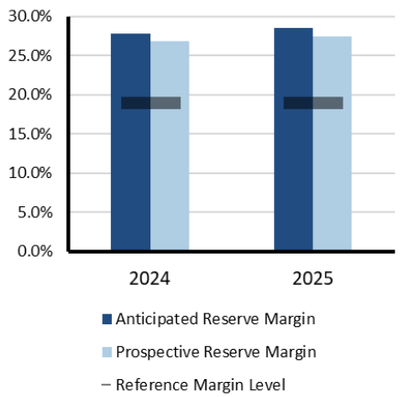
MRO-SPP

SPP PC's footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP long-term assessment is reported based on the PC footprint, which touches parts of the MRO Regional Entity and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million.

Highlights

- SPP projects a low likelihood of any emerging reliability issues impacting the area for the 2025 Summer season.
- Generation availability is not expected to be impacted by fuel shortages or river conditions this summer.
- BA generation capacity deficiency risks remain depending on wind generation output levels and unanticipated generation outages in combination with high load periods.
- Using the current operational processes and procedures, SPP will continue to assess the resource needs for the 2025 Summer season and will adjust generation and energy supply portfolios as needed to ensure that real-time energy sufficiency is maintained throughout the summer.

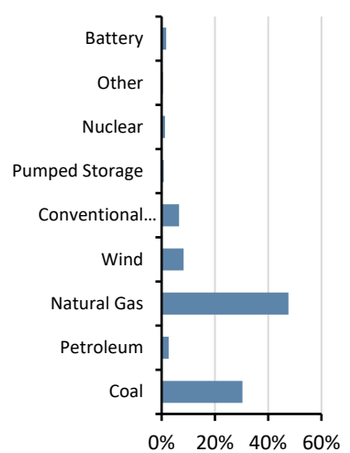
On-Peak Reserve Margin



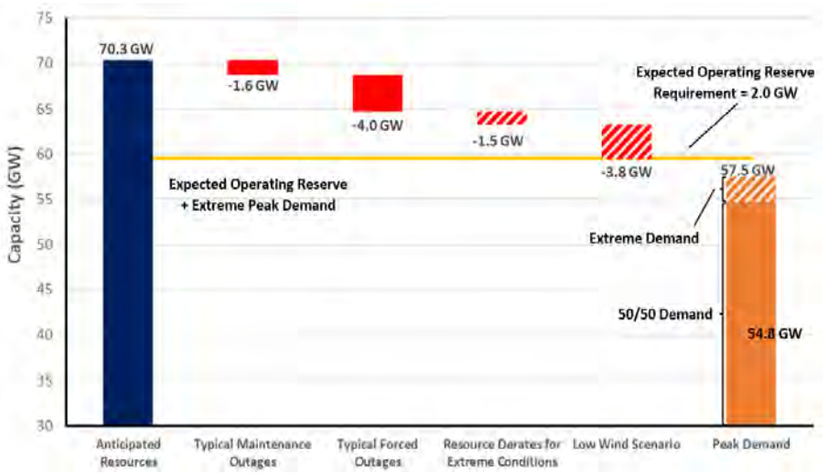
Risk Scenario Summary

Expected resources are sufficient to meet operating reserve requirements under normal peak-demand and outage scenarios. Above-normal summer peak load, low wind conditions, and higher-than-normal forced outages could result in the need for operating mitigations (e.g., demand response and transfers from neighboring systems) and EEAs.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand is a 5% increase from net internal demand

Maintenance and Forced Outages: Represent five-year historical averages; calculated from SPP's generation assessment process

Extreme Derates: Additional unavailable capacity from operational data at high-demand periods

Low Wind Scenario: Derates reflecting a low-wind day in the summer



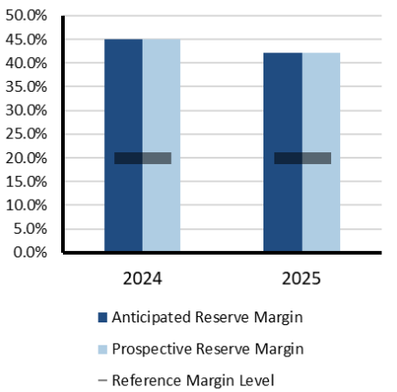
NPCC-Maritimes

The Maritimes assessment area is a winter-peaking NPCC area that contains two BAs. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, and Prince Edward Island and the northern portion of Maine, which is radially connected to the New Brunswick power system. The area covers 58,000 square miles with a total population of 1.9 million.

Highlights

- As Maritimes is a winter-peaking system, no issues are expected for the upcoming summer assessment period with sufficient firm capacity to meet forecast peak demand. If an event were to occur, emergency operations and planning procedures are in place.
- Probabilistic analysis performed by NPCC for the NPCC *Summer Reliability Assessment* found negligible LOLH and EUE for the expected load and resource levels this summer. A scenario with an extreme high load shape produced minimal amounts of cumulative LOLE (<0.089 days/period), LOLH (<0.4 hours/period), or EUE (< 16.5 MWh/period) over the May–September summer period with the highest risk occurring in July and August.
- Dual-fueled units will have sufficient supplies of heavy fuel oil (HFO) on site to sustain operations in the event of natural gas supply interruptions.

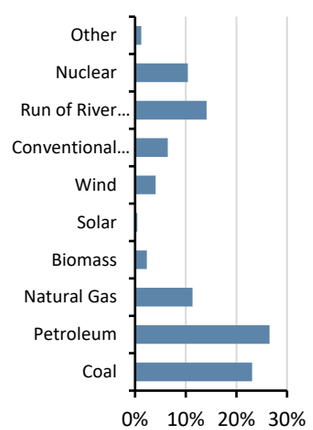
On-Peak Reserve Margin



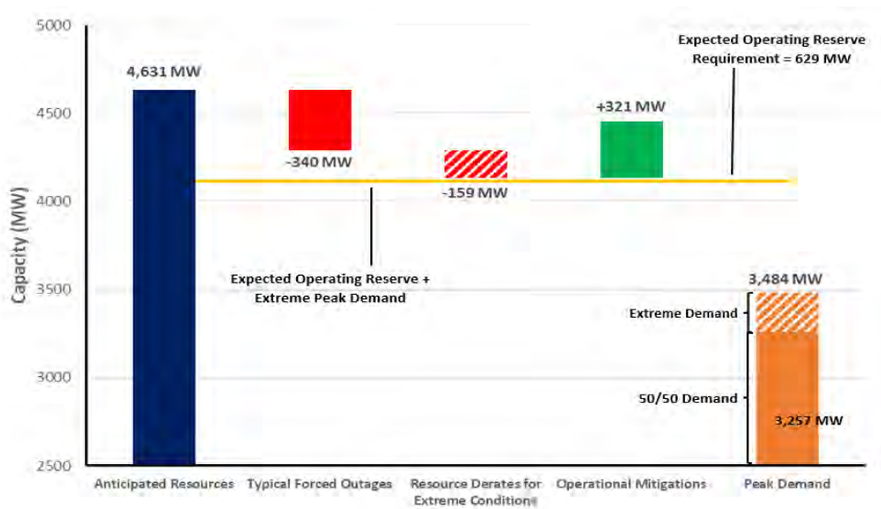
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load or extreme outage conditions could necessitate operating mitigations (e.g., demand response and non-firm transfers) and EEAs.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (above 90/10) extreme demand forecast

Forced Outages: Based on historical operating experience

Extreme Derates: A low-likelihood scenario resulting in an additional 50% derate in the remaining capacity of both natural gas and wind resources under extreme conditions

Operational Mitigations: Imports anticipated from neighbors during emergencies, (e.g. New Brunswick Power System Operator can increase import capability from 200 MW to 550 MW under emergency operations for up to 30 minutes)



NPCC-New England

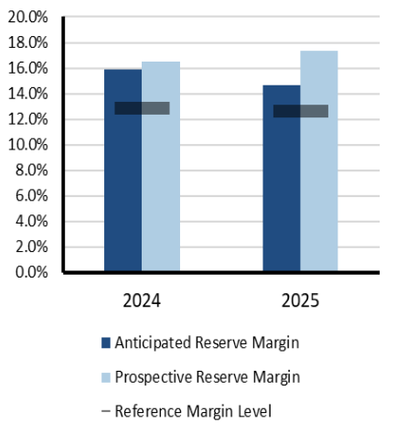
NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont that is served by ISO New England (ISO-NE) Inc. ISO-NE is a regional transmission organization that is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administration of the area's wholesale electricity markets, and management of the comprehensive planning of the regional BPS.

The New England BPS serves approximately 14.5 million customers over 68,000 square miles.

Highlights

- ISO-NE forecasts adequate transmission capability and manageable capacity margins to meet the expected peak demand.
- Probabilistic analysis performed by NPCC for the NPCC *Summer Reliability Assessment* identified small amounts of cumulative LOLE, LOLH, and EUE for the expected load with anticipated resources for the summer. A reduced resources and highest peak load level scenario resulted in an estimated cumulative LOLE risk of 4.369 days/period, with associated LOLH (19.554 hours/period) and EUE (19,847 MWh/period). The highest risk occurs in June, with some risk in July and August.
- The NPCC 2025 *Summer Reliability Assessment* will be approved on or about May 12, 2025, and posted on NPCC's website.

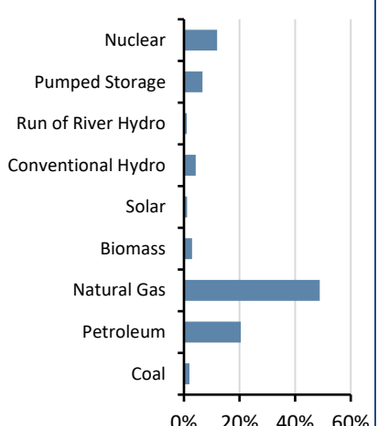
On-Peak Reserve Margin



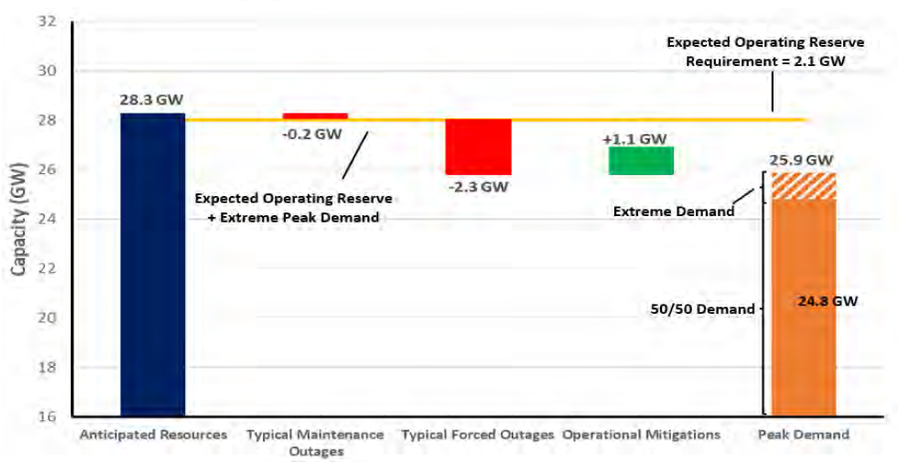
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under normal peak-demand and outage scenarios. Additional non-firm transfers are likely to be needed and available from neighbors. More severe conditions (e.g., above-normal summer peak load and outage conditions) could result in an EEA.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Peak net internal demand (50/50) and (90/10) extreme demand forecast

Maintenance Outages: Based on historical weekly averages

Typical Forced Outages: Based on seasonal capacity of each resource as determined by ISO-NE

Operational Mitigations: Based on load and capacity relief assumed available from invocation of ISO-NE operating procedures



NPCC-New York

NPCC-New York is an assessment area consisting of the New York ISO (NYISO) service territory. NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. NYISO is the only BA within the state of New York. The BPS in New York encompasses over 11,000 miles of transmission lines and 760 power generation units and serves 20.2 million customers. For this *SRA*, the established Reference Margin Level is 15%. Wind, grid-connected solar PV, and run-of-river totals were derated for this calculation. However, New York requires load-serving entities to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council. The council approved the 2025–2026 IRM at 24.4%.

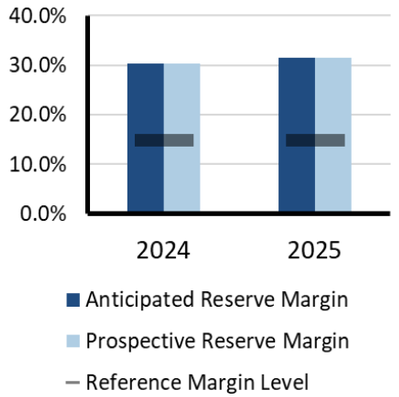
Highlights

- NYISO is not anticipating any operational issues for the upcoming summer operating period. Adequate reserve margins are anticipated.
- Probabilistic analysis performed by NPCC for the NPCC *Summer Reliability Assessment* found that use of New York's established operating procedures are sufficient to maintain a balance between electricity supply and expected 50/50 demand if needed to mitigate resource shortages during Summer 2025. Negligible cumulative LOLE (<0.018 days/period), LOLH (<0.054 hours/period), and EUE (33 MWh/period) risks were estimated over the summer May to September period for the expected load with expected resources for the summer. The highest peak load level with low likelihood reduced resource conditions resulted in an estimated cumulative LOLE risk (1.7 days/period), with associated LOLH (6.5 hours/period) and EUE (4860 MWh/period) with the highest risk occurring in July and August.
- The NPCC 2025 *Summer Reliability Assessment* will be approved on or about May 12, 2025, and posted on NPCC's website.

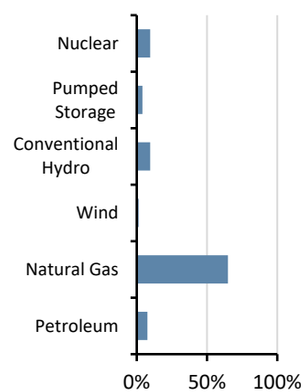
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios. Operating mitigations (e.g., demand response and transfers) may be needed to meet above-normal summer peak load and outage conditions.

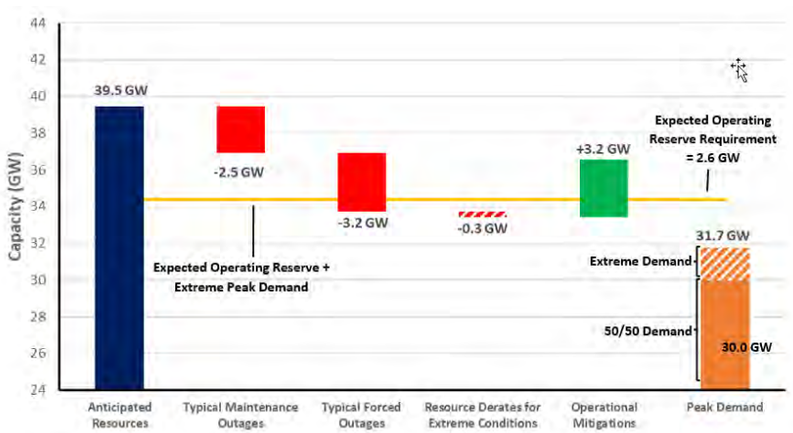
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) extreme demand forecast

Maintenance Outages: Based on historical performance and the new NYISO capacity accreditation process

Forced Outages: Based on historical five-year averages

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: A total of 3.2 GW based on operational/emergency procedures in area emergency operations manual



NPCC-Ontario

NPCC-Ontario is an assessment area in the Ontario province of Canada. The Independent Electricity System Operator (IESO) is the BA for the province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of m16 million. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

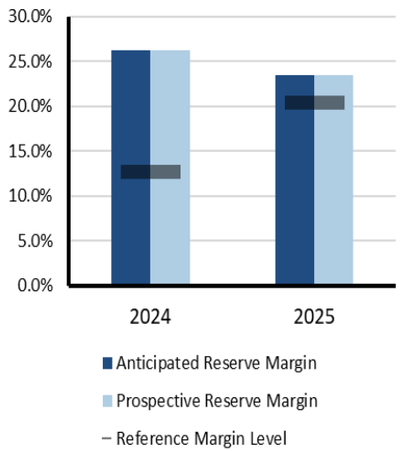
Highlights

- Overall, Ontario is operating within a period where generation and transmission outages are more challenging to accommodate. The IESO is prepared and expects to have adequate supply for Summer 2025.
- The IESO has been actively coordinating and planning with market participants to maintain reliability.
- This season, the grid will benefit from increased capacity secured through the capacity auction and more planned projects, including new storage, coming into service.
- The IESO is working throughout 2025 to better integrate storage solutions into the electricity markets.
- Starting with this seasonal assessment, demand is forecasted by using probabilistic weather modeling, comparable to the methodology used in the IESO 18-month *Reliability Outlook* as opposed to the previous approach of using weather scenarios."

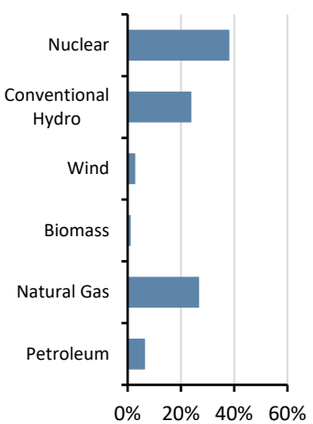
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

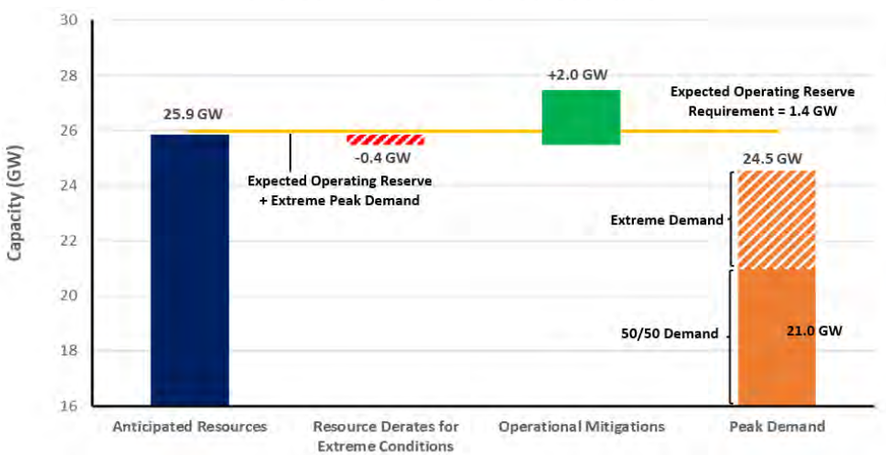
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50 forecast) and highest weather-adjusted daily demand based on 31 years of demand history, and extreme weather represents a 97/3 distribution of probabilistically modelled data

Extreme Derates: Derived from weather-adjusted temperature rating of thermal units and adjustments to expected hydro production for low water conditions

Operational Mitigations: The operational procedures used to mitigate extreme conditions total approximately 2,010 MW for the On-Peak Risk Scenario, consisting of imports, public appeals, and voltage reductions. Public appeals and voltage reductions were not included in the 2024 On-Peak Risk Scenario.



NPCC-Québec

The Québec assessment area (province of Québec) is a winter-peaking NPCC area that covers 595,391 square miles with a population of 8 million. Québec is one of the four Interconnections in North America; it has ties to Ontario, New York, New England, and the Maritimes consisting of either high-voltage direct current ties, radial generation, or load to and from neighboring systems.

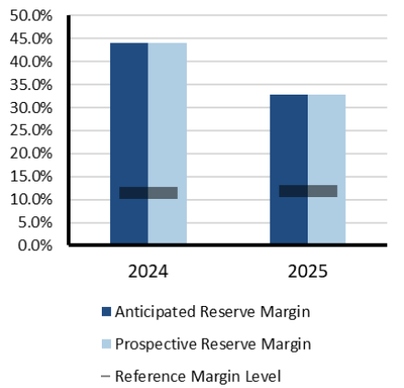
Highlights

- The Québec area forecasted summer peak demand is 23,283 MW during the week beginning August 3, 2025, with a forecasted net margin of 5,698 MW (24.5%).
- Resource adequacy issues are not expected this summer.
- The Québec area expects to be able to assist other areas.
- Modeling was made more precise this year with the inclusion of summer demand-response programs, dispatchable demand-side management (DSM), and weekly modeling of the reserve requirements and bottled generation.

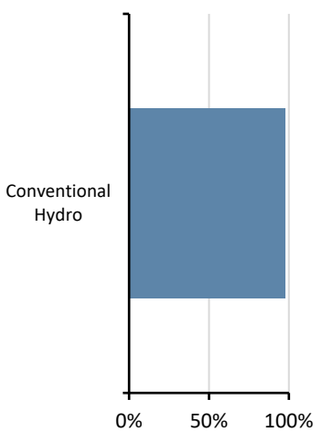
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

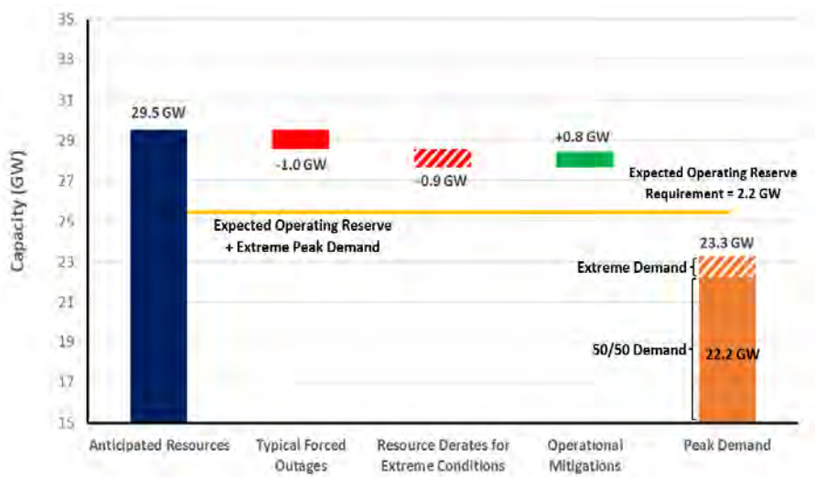
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenario: Net internal demand (50/50) and (90/10) demand forecast

Operational mitigations: An operational procedure used to mitigate extreme conditions and not already included in margins is the depletion of some operating reserves by 750 MW.



PJM

PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM serves 65 million customers and covers 369,089 square miles. PJM is a BA, PC, Transmission Planner, Resource Planner, Interchange Authority, TOP, Transmission Service Provider, and RC.

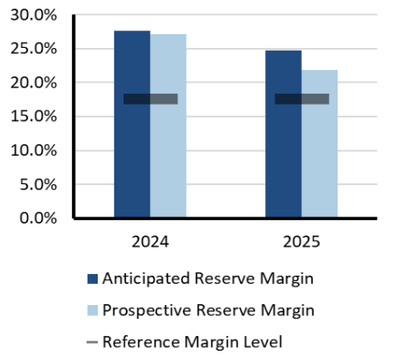
Highlights

- PJM is forecasting 27% installed reserves (including expected committed demand response), which is above the target installed reserve margin of 17.7% necessary to meet the 1-day-in-10-years LOLE criterion.
- During extreme high temperatures that can cause record demand, PJM anticipates the need for demand-response resources to help reduce load at times this summer.

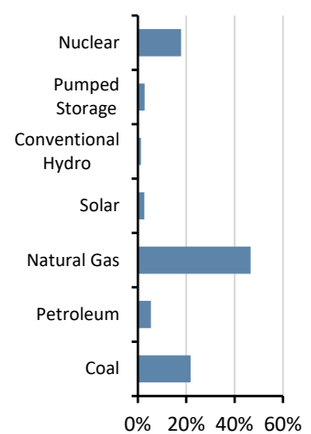
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

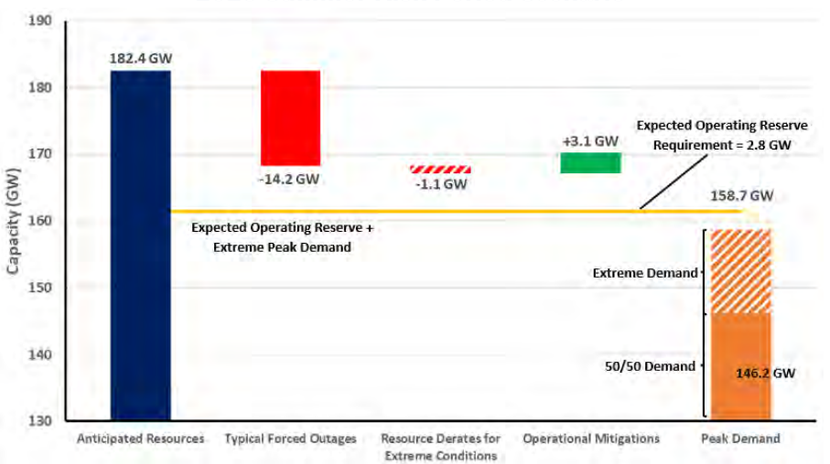
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Based on historical data and trending

Extreme Derates: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 3 GW based on operational/emergency procedures



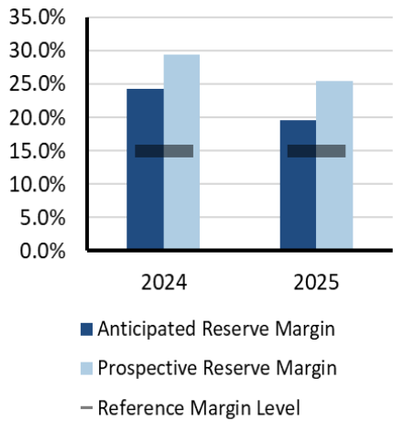
SERC-Central

SERC-Central is an assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. Historically a summer-peaking area, SERC-Central is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission (FERC)-approved delegation agreements with NERC. SERC-Central is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

Highlights

- SERC-Central saw a sizable increase in its reserves last summer, but coal retirements this summer will result in SERC-Central having lower reserves.
- SERC-Central's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- The probabilistic analysis metrics indicate adequate energy resources for the area.
- Entities perform resource studies to ensure resource adequacy to meet the summer peak demand and maintain the reliability of the system.
- Members of SERC-Central actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.

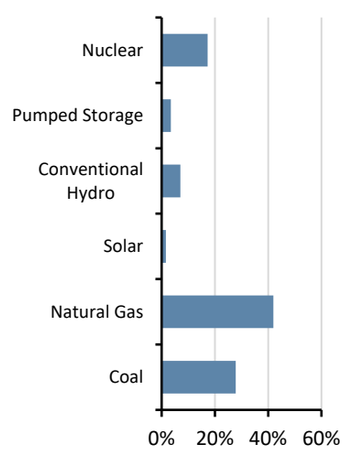
On-Peak Reserve Margin



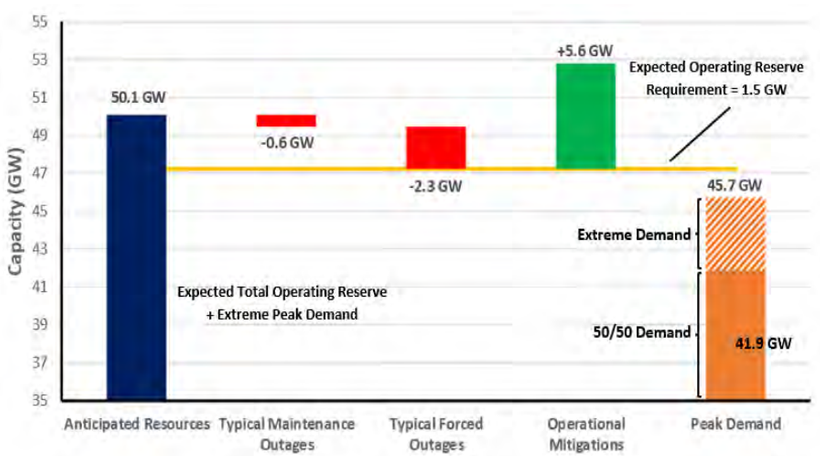
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios. More severe conditions (e.g., above-normal summer peak load and outage conditions) result in the need for additional non-firm transfers available from neighbors.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: 5.6 GW based on operational/emergency procedures



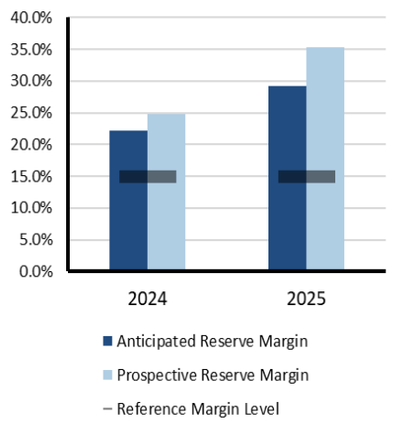
SERC-East

SERC-East is an assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina. Historically a summer-peaking area, SERC-East is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

Highlights

- SERC-East's reserves are largely unchanged compared to the reference margin as compared to last summer's assessment.
- SERC-East's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- While the last probabilistic analysis indicated that SERC-East could face potential unserved energy in summer, the 2026 and 2028 probabilistic analysis found the SERC-East unserved energy risk has shifted to winter mornings.
- Members of SERC-East actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.

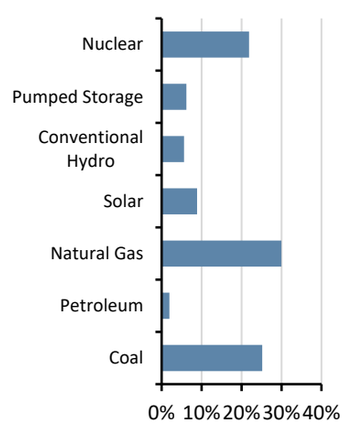
On-Peak Reserve Margin



Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 45 MW based on operational/emergency procedures



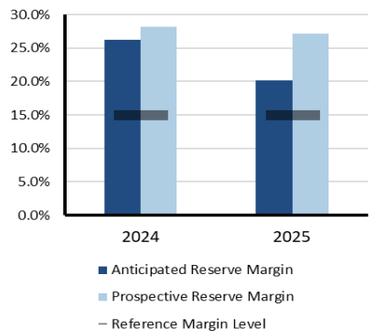
SERC-Florida Peninsula

SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

Highlights

- SERC Florida-Peninsula's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- The probabilistic analysis metrics indicate adequate energy resources for the subregion during the summer.
- Members of SERC-Florida Peninsula actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.
- Entities have not identified any emerging reliability issues or operational concerns for the upcoming summer season.

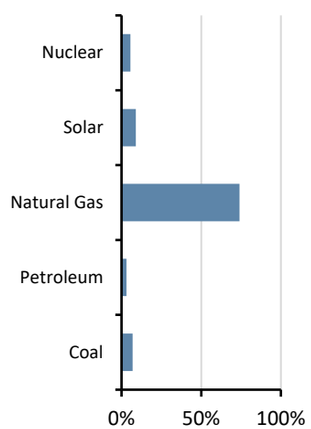
On-Peak Reserve Margin



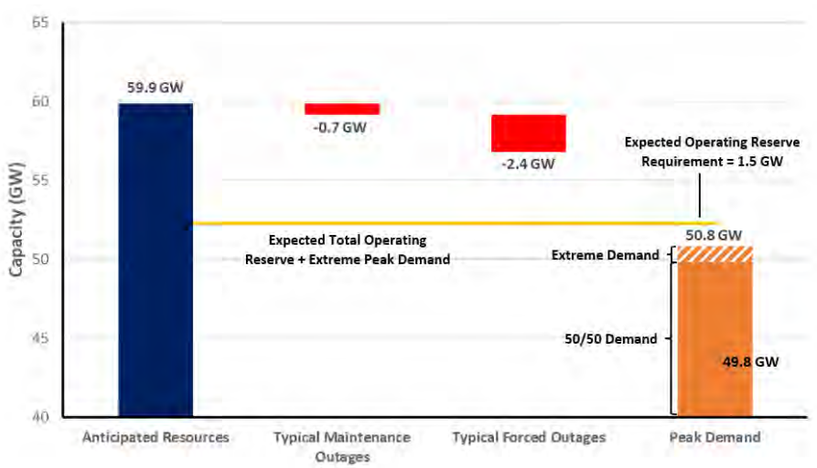
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions



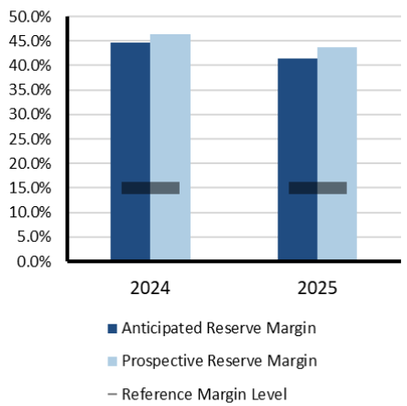
SERC-Southeast

SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

Highlights

- An area within SERC-Southeast notes that natural gas pipeline constraints could impact reliability in summer, but this is not expected to pose a significant summer operational challenge.
- SERC-Southeast's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- The probabilistic analysis metrics indicate adequate energy resources for the subregion.
- Members of SERC-Southeast actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.

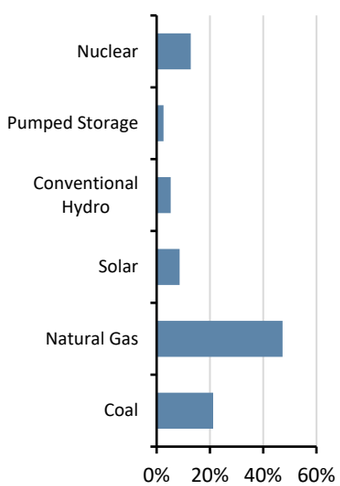
On-Peak Reserve Margin



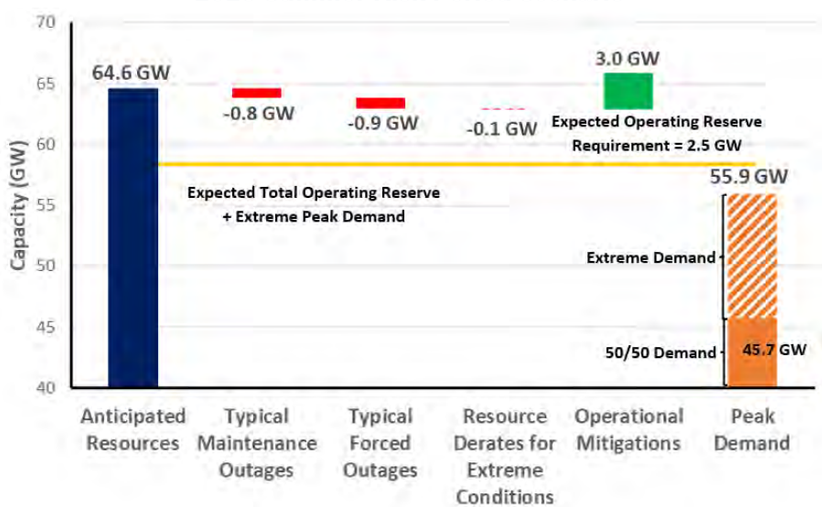
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: A total of 3 GW based on operational/emergency procedures



Texas RE-ERCOT

The Electric Reliability Council of Texas (ERCOT) is the independent system operator (ISO) for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT is summer-peaking, and the forecasted summer peak load month is August. It covers approximately 200,000 square miles, connects over 52,700 miles of transmission lines, has over 1,100 generation units, and serves more than 26 million customers. Texas RE is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT. On November 3, 2022, the Public Utility Commission of Texas issued an order directing ERCOT to assume the duties and responsibilities of the reliability monitor for the Texas grid.

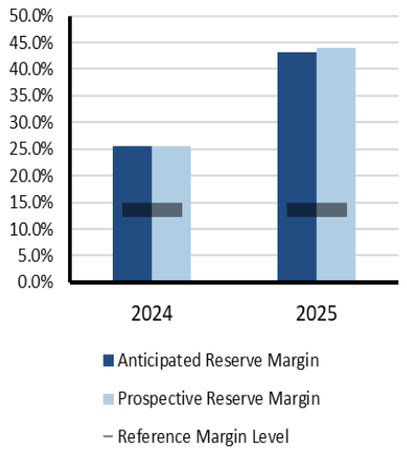
Highlights

- ERCOT expects to have sufficient operating reserves for the August peak load hour given normal summer system conditions.
- ERCOT's probabilistic risk assessment indicates a low risk of having to declare EEAs during the expected August (and summer) peak load day; the EEA probability for the highest-risk hour—hour ending 9:00 p.m.—is 3.6%. The likelihood of an EEA is down significantly from the 2024 SRA due to almost a doubling of battery energy storage capacity and improved energy availability reflecting new battery storage and operational rules.
- Continued robust growth in both loads and intermittent renewable resources drives a higher risk of emergency conditions in the evening hours when solar generation ramps down and loads remain elevated.
- The South Texas IROL continues to present a risk of ERCOT directing system-wide firm load shedding to remain within IROL limits. This risk has been mitigated by updating transmission line dynamic ratings and switching actions to divert power away from the most limiting transmission circuits. The South Texas transmission limits are expected to be needed at least until the San Antonio South Reliability Project is placed in service, which is anticipated to be in Summer 2027.
- ERCOT will release its own August 2025 Monthly Outlook for Resource Adequacy on June 6.

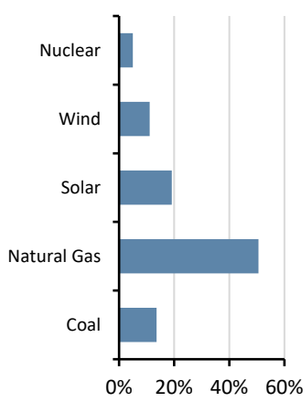
Risk Scenario Summary

Expected resources meet operating reserve requirements for the peak demand hour scenario. However, there is a risk of supply shortages during evening hours (when solar generation ramps down and demand remains high) if there are conventional generation forced outages or extreme low-wind conditions.

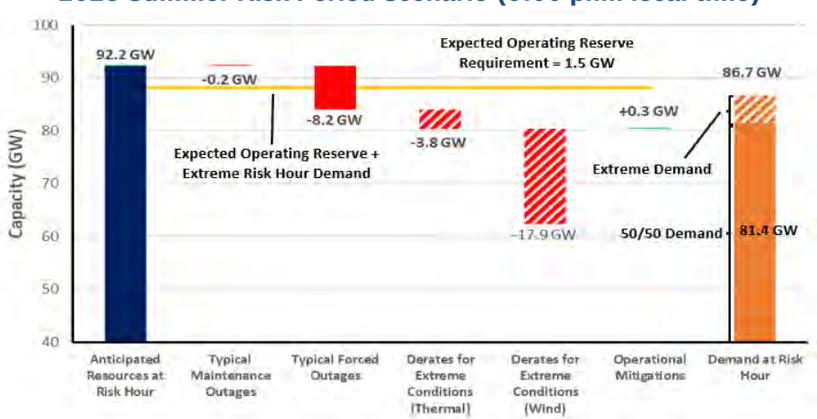
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario (9:00 p.m. local time)



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at hour ending 9 p.m. local time as solar PV output is diminished and demand remains high

Demand Scenarios: Net internal demand (50/50) and extreme demand (95/5) based on August peak load

Forced Outages: Based on the 95th percentile of historical averages of forced outages for June through September weekdays, hours ending 3:00–8:00 p.m. local time for the last three summer seasons

Extreme Derates: Based on the 90th percentile of thermal forced outages for peak August load day

Low Wind Scenario: Based on the 10th percentile of historical averages of hourly wind for June through September, hours ending 1:00–9:00 p.m. local time

Operational Mitigations: Additional capacity from switchable generation and additional imports



WECC-Alberta

WECC-Alberta is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of Alberta. It has 16,369 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

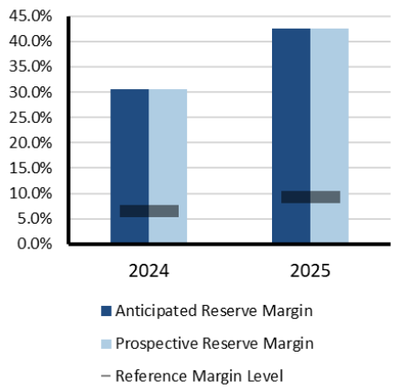
Highlights

- Anticipated and prospective reserve margins are projected to remain above the Reference Margin Level.
- All resource margins have increased by about 50% since last summer with the addition of 23.2% new capacity, including almost 2,700 MW of new natural gas capacity, 1,200 MW of new wind (+27%), 200 MW of new solar (+13%), and 54 MW of new energy storage systems (+27.5%).
- The peak hour has moved earlier, to 3:00 p.m. from 4:00 p.m., still in late July.
- High temperatures, import limitations, and low or declining renewable output during summer evenings can result in grid alerts.
- Wildfires can threaten generating assets and transmission infrastructure requiring invocation of Alberta Electric System Operator (AESO) protocols that include instructing available assets and long lead-time assets to deliver energy up to their maximum capability, calling upon demand response, and maximizing import capability.

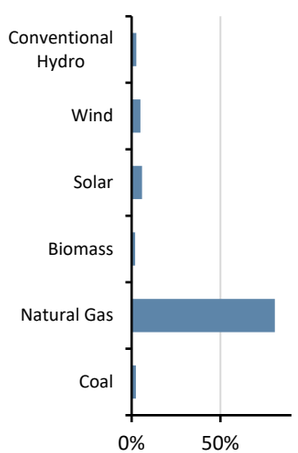
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

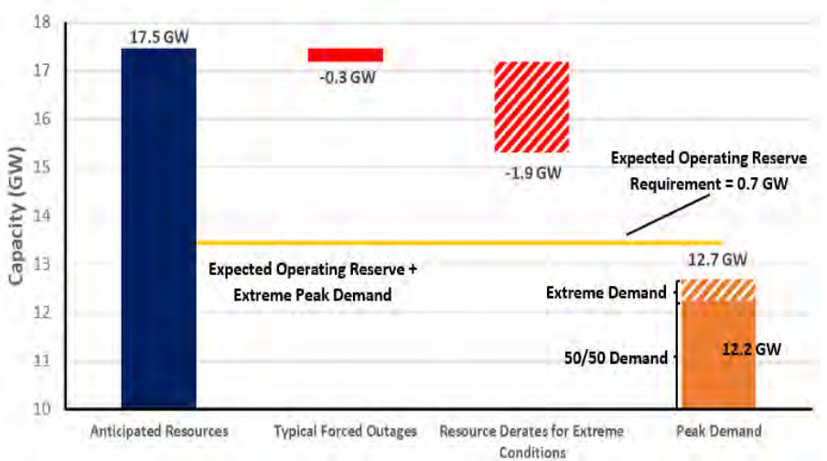
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Typical Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) point of resource performance distribution



WECC-Basin

WECC-Basin is a summer-peaking assessment area in the WECC Regional Entity that includes Utah, southern Idaho, and a portion of western Wyoming, covering Idaho Power and PacifiCorp's eastern Balancing Authority Area. The population of this area is approximately 5.4 million. It has 15,910 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024 SRA.*

Highlights

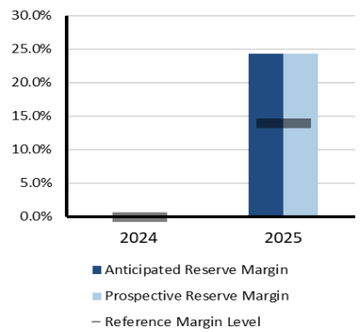
- Total internal expected demand has increased 8% and demand response has increased almost 28% for a net internal demand increase of 7.2%.
- Reserve margins are not anticipated to fall below the reference margin (14%) for the upcoming summer; an early July peak is expected at around 3:00 p.m.
- During periods of contingency reserve shortage, EEAs may be declared in the region to obtain reserves from the Northwest Power Pool.
- Seasonal fluctuations in hydro supply require monitoring and forecasting to have high certainty that these resources will meet anticipated capacity; the Summer 2025 drought outlook for the United States indicates minimal drought conditions in Idaho and some drought areas in Utah this summer.
- Wildfires near wind generation can result in safety curtailments, and fire damage to transmission lines interconnected to hydro sites can present restoration challenges.

Risk Scenario Summary

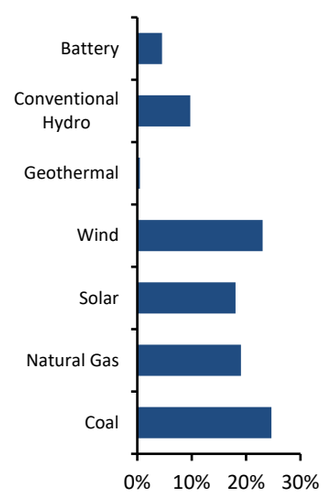
Expected resources meet operating reserve requirements under the assessed scenarios with imports.

On-Peak Reserve Margin

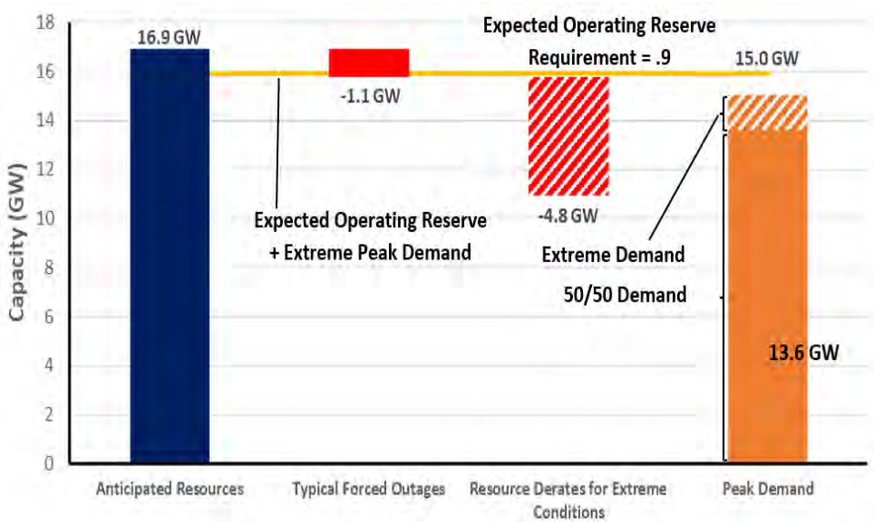
(Note: year comparison not available)



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) resource performance distribution at peak hour



WECC-British Columbia

WECC-British Columbia (BC) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of British Columbia. It has 11,184 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

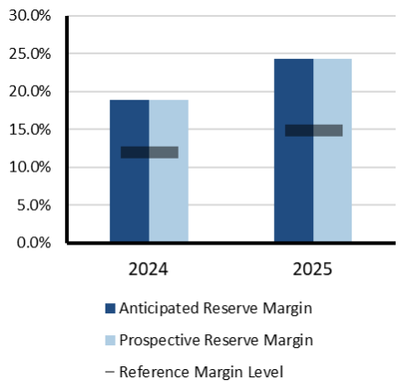
Highlights

- Existing capacity reserve margin has increased from 19% to 22%, and anticipated and prospective reserve margin from 19% to 24%.
- Reserve margins are not anticipated to fall below the reference margin for the upcoming summer.
- The peak hour is forecast for early August at 4:00 p.m., two hours earlier than last summer's outlook of 6:00 p.m.
- About 60% of hydro owned or contracted energy comes from the Columbia and Peace basins. Heavy precipitation in Fall 2024 mitigated the impact of below-average snowpack the previous winter, resulting in hydro storage tracking close to historical averages as of Spring 2025.
- Wildfires can affect the transmission network and generator availability and have caused energy emergencies on the electric system in the past.

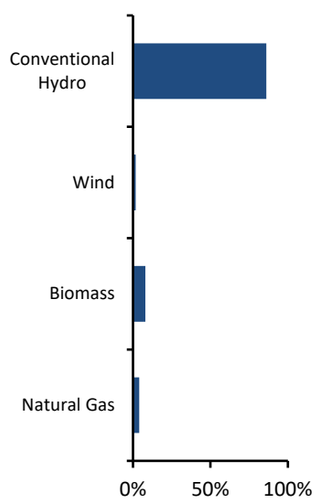
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

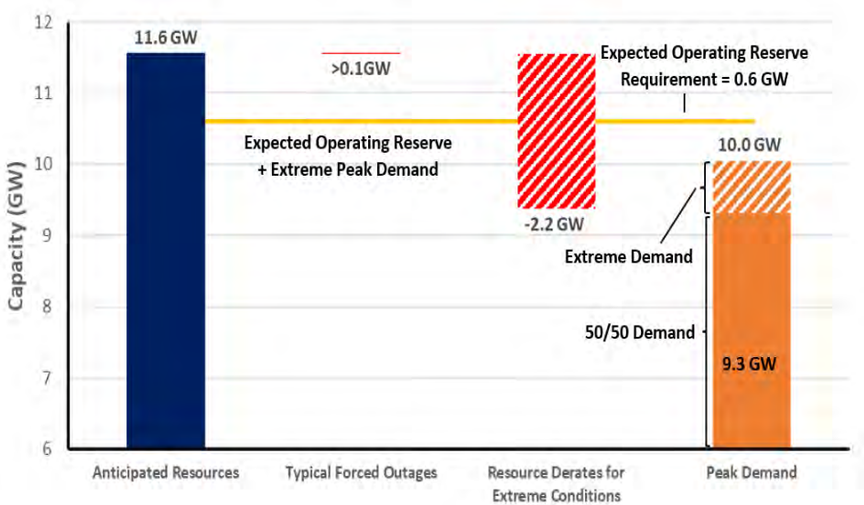
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) resource performance distribution at peak hour



WECC-California

WECC-California is a summer-peaking assessment area in the Western Interconnection that includes most of California and a small section of Nevada. The assessment area has a population of over 42.5 million people. The area includes the California ISO, Los Angeles Department of Water and Power, Turlock Irrigation District, and the Balancing Area of Northern California. It has 32,712 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-California is a new assessment area in 2025 that was part of WECC-CA/MX in the 2024 SRA*.

Highlights

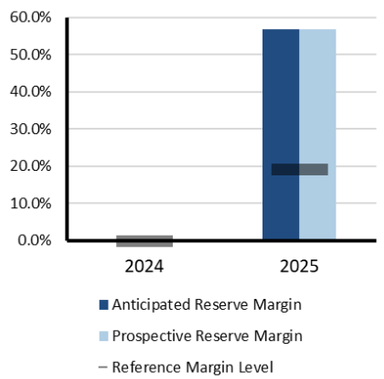
- Demand response is down 8.6% since last summer, existing-certain capacity is up 5.8%, and Tier 1 planned capacity is up 41.2% for a net increase in anticipated resources of 9%; anticipated and prospective reserve margins are up by 11.4%. The peak hour is still forecasted for early September around 4:00 p.m.
- Reserve margins are not anticipated to fall below the reference margin for the upcoming summer, and probabilistic assessment of normal and extreme resource/demand scenarios reveal no EUE or LOLH.
- Wildfires can and have threatened both the California Oregon Intertie line, resulting in import capability limitations.
- Prolonged elevated demand during heat waves in combination with thermal resource derates and forced outage rates present significant risk.
- An influx of IBRs and corresponding reduction in system inertia can potentially trigger system reliability issues and require additional regulation, flexible ramp, and future imbalance reserve requirements.
- Increased solar penetrations in this region along with changing load patterns from elevated temperatures and residential demand are shifting the hours with the most challenging resource adequacy needs later into the evening rather than traditional afternoon gross peak load periods.

Risk Scenario Summary

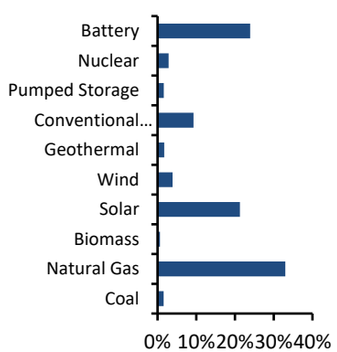
Expected resources meet operating reserve requirements under assessed scenarios, and a probabilistic assessment of normal and extreme resource/demand scenarios reveals neither EUE nor LOLH.

On-Peak Reserve Margin

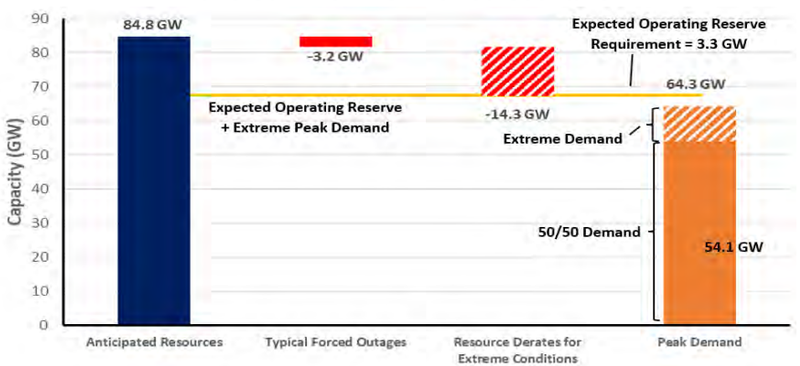
(Note: year comparison not available)



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Estimated using market forced outage model

Extreme Derates: On natural gas units based on historical data and manufacturer data for temperature performance and outages



WECC-Mexico

WECC-Mexico is a summer-peaking assessment area in the Western Interconnection that includes the northern portion of the Mexican state of Baja California, which has a population of 3.8 million people and includes CENACE. It has 1,568 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Mexico is a new assessment area in 2025 that was part of WECC-CA/MX in the 2024 SRA.*

Highlights

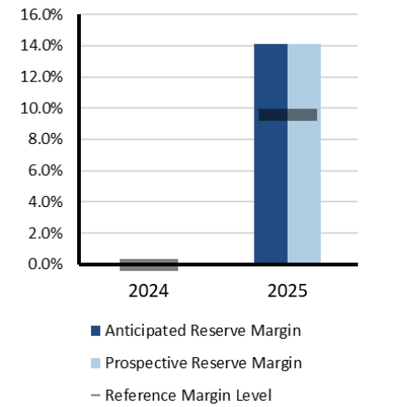
- Total and net internal expected (50/50) demand are up 6.8%, existing-certain capacity is up 29.8% or 989 MW, and Tier 1 planned capacity has fallen 100% to zero, leading to a decrease in the anticipated reserve margin from 22.9% down to 14.1%
- The peak hour is expected to occur in early August around 4:00 p.m.
- Operating reserves are a concern in this region during periods of extreme heat and elevated demand. High loading on Path 45 (See: WECC Path Rating Catalog) coupled with outages or derates to large thermal assets in this region can result in the declaration of an EAA and a request for assistance from RC West.

Risk Scenario Summary

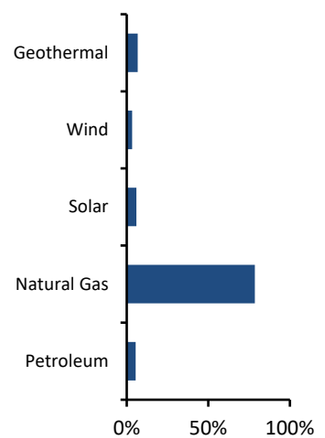
Expected resources at normal peak demand and outage conditions require some imports to maintain operating reserves. Thus, above-normal demand, high forced outage conditions, or transmission derates in the neighboring area could place WECC-Mexico in an energy emergency.

On-Peak Reserve Margin

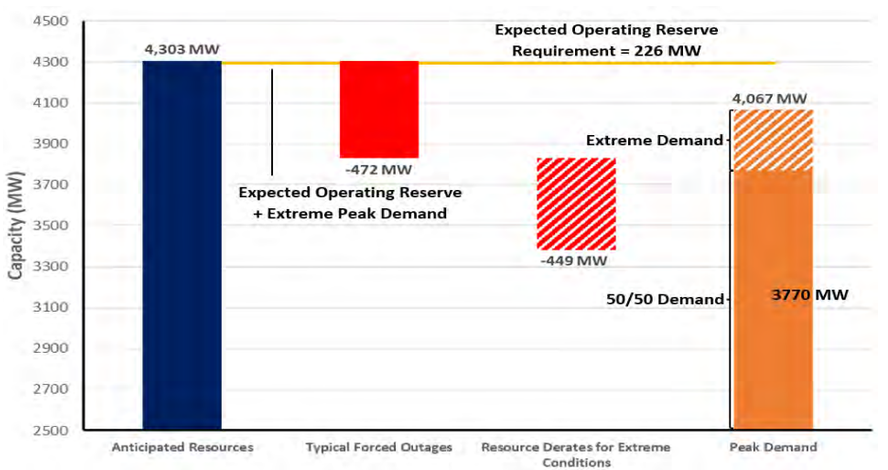
(Note: year comparison not available)



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) resource performance distribution at peak hour



WECC-Rocky Mountain

WECC-Rocky Mountain is a summer-peaking assessment area in the Western Interconnection that includes Colorado, most of Wyoming, and parts of Nebraska and South Dakota. The population of the area is approximately 6.7 million. It covers the balancing areas of the Public Service Company of Colorado and the Western Area Power Administration's Rocky Mountain Region. It has 18,797 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Rocky Mountain is a new assessment area in 2025 that was part of WECC-NW in the 2024 SRA*.

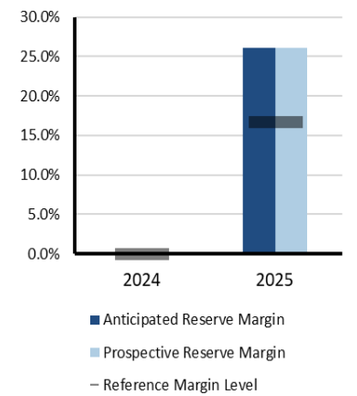
Highlights

- The reserve margins (existing-certain 25% and anticipated and prospective 26%) are not anticipated to fall below the reference margin (17%) for Summer 2025.
- Total and net internal demand (50/50) is up 25% or almost 2,800 MW, leading to a decline in the Anticipated Reserve Margin by almost a third.
- During the summer, there is increased load and decreased market purchase availability. Low wind availability and ramping scarcity events are a concern.
- Environmental and ecological factors have contributed to a rise in wildfire frequency and shortening of the fire return interval in the Rocky Mountain region, which, in addition to having caused generation outages, threatens rural co-ops disproportionately due to the extensive line buildout over remote regions.

Risk Scenario Summary

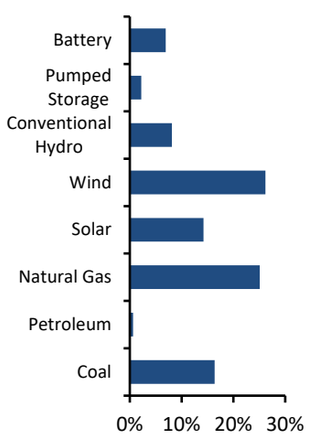
Expected resources meet operating reserve requirements under assessed scenarios with imports.

On-Peak Reserve Margin

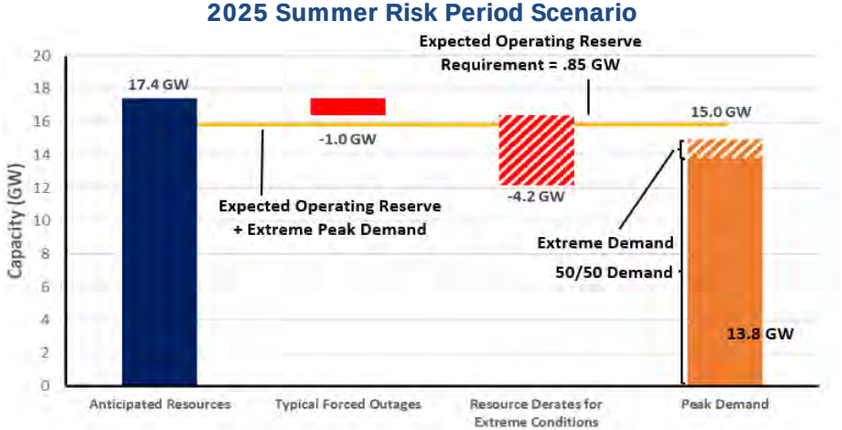


(Note: year comparison not available)

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario



WECC-Northwest

WECC-Northwest is a winter-peaking assessment area in the WECC Regional Entity. The area includes Montana, Oregon, and Washington and parts of northern California and northern Idaho. The population of the area is approximately 13.6 million. It has 32,751 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Northwest is a new assessment area in 2025 that was part of a larger WECC-NW footprint in the 2024 SRA.*

Highlights

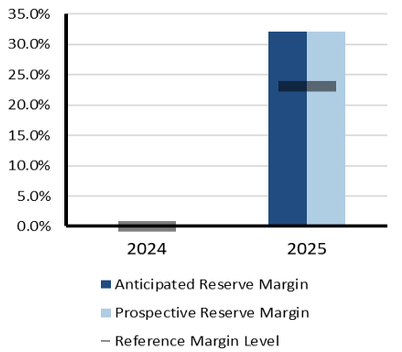
- The reserve margins (existing-certain 29% and anticipated and prospective 32%) are not anticipated to fall below the reference margin (23%) for the upcoming summer. An extreme summer peak load may be around 32,740 MW.
- Typical forced outages are forecast to be 771 MW, with derates for thermal under extreme conditions to be 1,584 MW and 2,649 MW for wind. The expected operating reserve requirement on peak is 1,750 MW.
- Extreme heat corresponds with elevated loads, reduced transmission ratings, and temperature derates of thermal resources, which can strain resource adequacy and grid reliability.
- Seasonal hydro variability is a risk.

Risk Scenario Summary

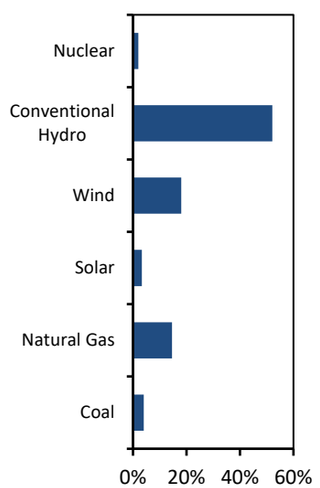
Expected resources meet operating reserve requirements under assessed scenarios with imports.

On-Peak Reserve Margin

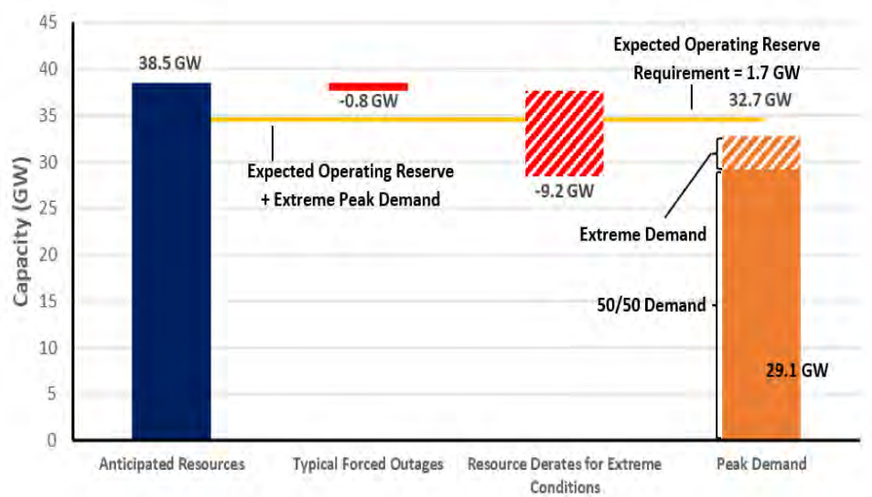
(Note: year comparison not available)



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario



WECC-Southwest

WECC-Southwest is a summer-peaking assessment area in the Western Interconnection that includes all of Arizona and New Mexico, most of Nevada, and small parts of California and Texas. The area has a population of approximately 13.6 million. It has 23,084 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Southwest is a new, larger assessment area in 2025 that now includes a portion of WECC-NW in the 2024 SRA.*

Highlights

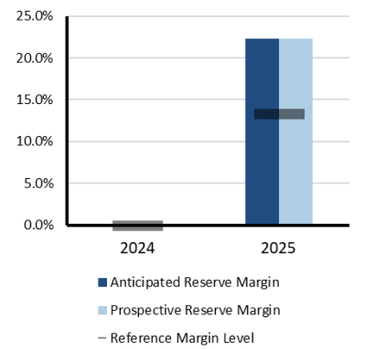
- Anticipated Reserve Margins for the summer are 22%, exceeding the Reference Margin Level for reliability calculated by WECC.
- WECC's probabilistic analysis indicates that the area is not expected to encounter LOLH or EUE under a range of demand and resource conditions.
- The peak hour is expected to occur in early July around 5:00 p.m., when solar generation output begins to diminish.
- Wide-area heat events or wildfires that affect resource and transmission availability across the western interconnection area a reliability concern for the Southwest. Firm imports may be limited at this time if neighboring areas are also experiencing peak loads, limiting energy availability to export to the Southwest.

Risk Scenario Summary

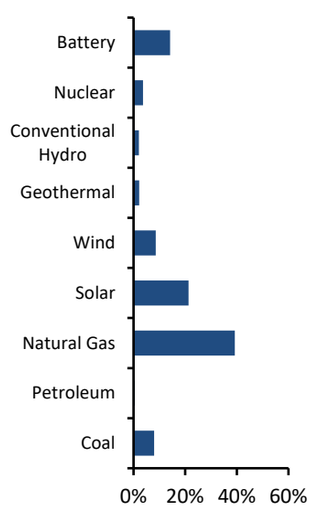
Expected resources meet operating reserve requirements under assessed scenarios with imports.

On-Peak Reserve Margin

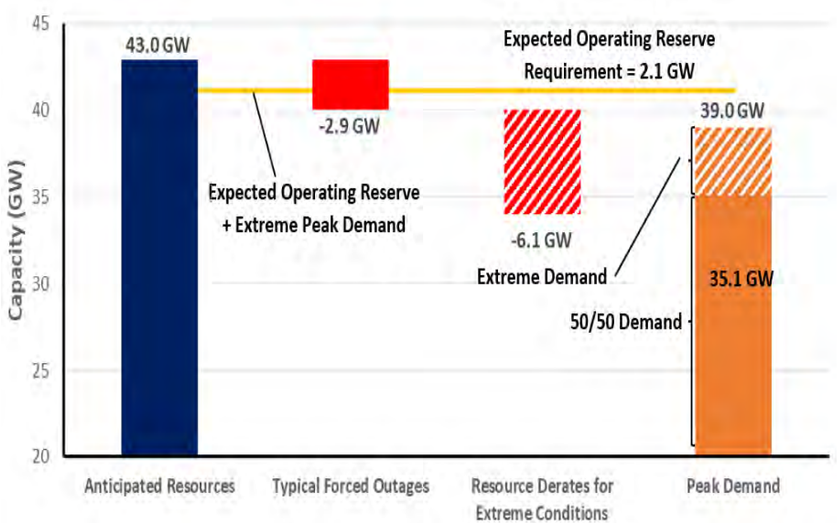
(Note: year comparison not available)



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand (5:00 p.m. local)

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Data Concepts and Assumptions

The table below explains data concepts and important assumptions used throughout this assessment.

General Assumptions
• Reliability of the interconnected BPS is comprised of both adequacy and operating reliability:
▪ Adequacy is the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
▪ Operating reliability is the ability of the electric system to withstand sudden disturbances, such as electric short-circuits or unanticipated loss of system components.
• The reserve margin calculation is an important industry planning metric used to examine future resource adequacy.
• All data in this assessment is based on existing federal, state, and provincial laws and regulations.
• Differences in data collection periods for each assessment area should be considered when comparing demand and capacity data between year-to-year seasonal assessments.
• A positive net transfer capability would indicate a net importing assessment area; a negative value would indicate a net exporter.
Demand Assumptions
• Electricity demand projections, or load forecasts, are provided by each assessment area.
• Load forecasts include peak hourly load[12] or total internal demand for the summer and winter of each year.[13]
• Total internal demand projections are based on normal weather (50/50 distribution)[14] and are provided on a coincident[15] basis for most assessment areas.
• Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour.
Resource Assumptions
Resource planning methods vary throughout the North American BPS. NERC uses the categories below to provide a consistent approach for collecting and presenting resource adequacy. Because the electrical output of VERs (e.g., wind, solar PV) depends on weather conditions, their contribution to reserve margins and other on-peak resource adequacy analysis is less than their nameplate capacity.
Anticipated Resources: • **Existing-Certain Capacity**: Included in this category are commercially operable generating units or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the summer season: unit must have a firm capability and have a power purchase agreement with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or, where energy-only markets exist, unit must be a designated market resource eligible to bid into the market. • **Tier 1 Capacity Additions**: This category includes capacity that either is under construction or has received approved planning requirements. • **Net Firm Capacity Transfers (Imports minus Exports)**: This category includes transfers with firm contracts.
Prospective Resources: Includes all anticipated resources plus the following: **Existing-Other Capacity**: Included in this category are commercially operable generating units or portions of generating units that could be available to serve load for the period of peak demand for the season but do not meet the requirements of existing-certain.

[12] https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf used in NERC Reliability Standards

[13] The summer season represents June–September and the winter season represents December–February.

[14] Essentially, this means that there is a 50% probability that actual demand will be higher and a 50% probability that actual demand will be lower than the value provided for a given season/year.

[15] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval; this is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year. SERC calculates total internal demand on a noncoincidental basis.

Reserve Margin Descriptions

Planning Reserve Margin: This is the primary metric used to measure resource adequacy; it is defined as the difference in resources (anticipated or prospective) and net internal demand then divided by net internal demand and shown as a percentage.

Reference Margin Level: The assumptions and naming convention of this metric vary by assessment area. The RML can be determined using both deterministic and probabilistic (based on a 0.1/year loss-of-load study) approaches. In both cases, this metric is used by system planners to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing an RML is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increase demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, an RML is established by a state, provincial authority, ISO/Regional Transmission Organization (RTO), or other regulatory body. In some cases, the RML is a requirement. RMLs may be different for the summer and winter seasons. If an RML is not provided by an assessment area, NERC applies 15% for predominantly thermal systems and 10% for predominantly hydro systems.

Seasonal Risk Scenario Chart Description

Each assessment area performed an operational risk analysis that was used to produce the seasonal risk scenario charts in the **Regional Assessments Dashboards**. The chart presents deterministic scenarios for further analysis of different resource and demand levels: The left **blue** column shows anticipated resources, and the two **orange** columns at the right show the two demand scenarios of the normal peak net internal demand and the extreme summer peak demand—both determined by the assessment area. The middle **red** or **green** bars show adjustments that are applied cumulatively to the anticipated resources, such as the following:

- Reductions for typical generation outages (i.e., maintenance and forced outages that are not already accounted for in anticipated resources)
- Reductions that represent additional outage or performance derating by resource type for extreme, low-probability conditions (e.g., drought condition impacts on hydroelectric generation, low-wind scenario affecting wind generation, fuel supply limitations, or extreme temperature conditions that result in reduced thermal generation output)
- Additional capacity resources that represent quantified capacity from operational procedures, if any, that are made available during scarcity conditions

Not all assessment areas have the same categories of adjustments to anticipated resources. Furthermore, each assessment area determined the adjustments to capacity based on methods or assumptions that are summarized below the chart. Methods and assumptions differ by assessment area and may not be comparable.

The chart enables evaluation of resource levels against levels of expected operating reserve requirement and the forecasted demand. Furthermore, the effects from extreme events can also be examined by comparing resource levels after applying extreme scenario derates and/or extreme summer peak demand.

Resource Adequacy

The Anticipated Reserve Margin (ARM), which is based on available resource capacity, is a metric used to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecast peak demand.[16] Large year-to-year changes in anticipated resources or forecast peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. All assessment areas have sufficient ARMs to meet or exceed their RML for the summer 2025 as shown in **Figure 4**.

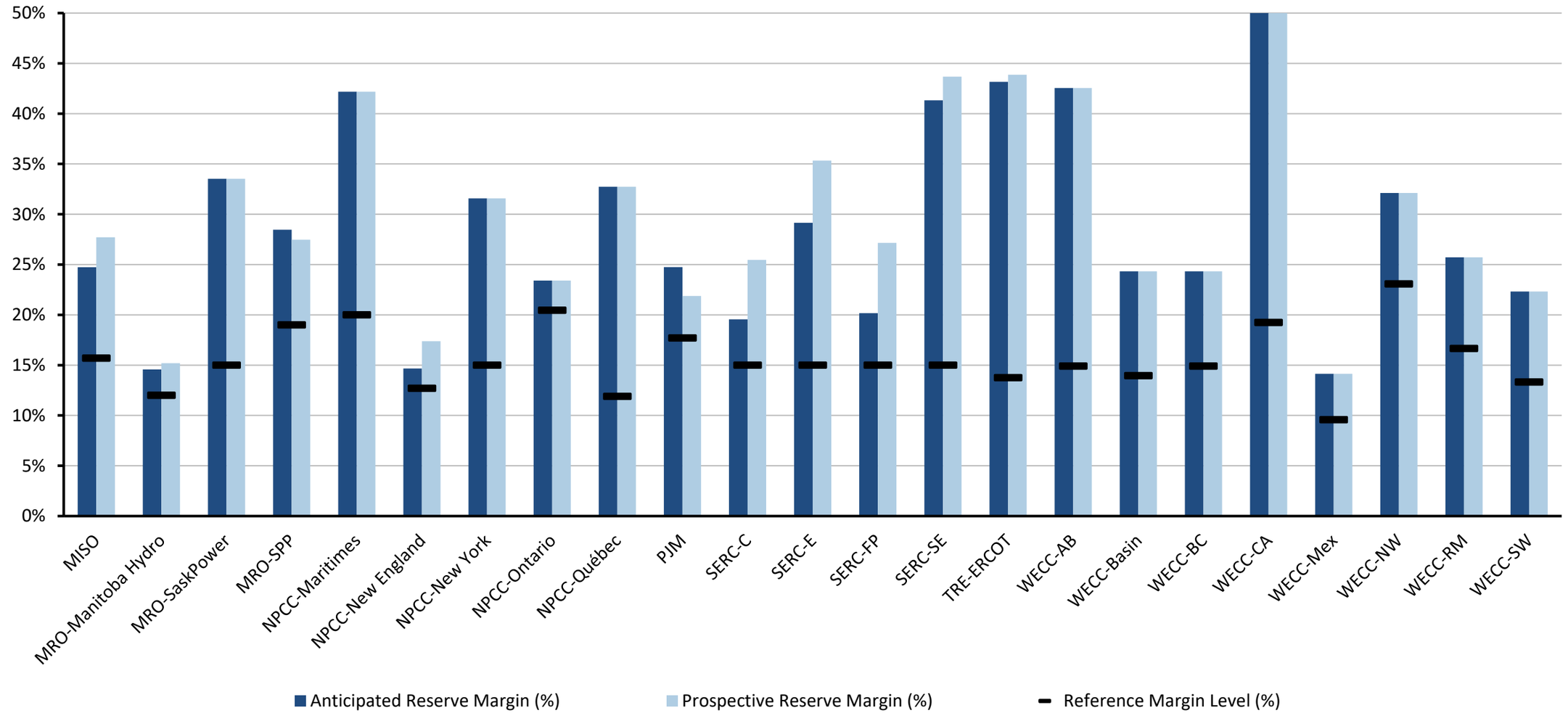


Figure 4: Summer 2025 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[16] Generally, anticipated resources include generators and firm capacity transfers that are expected to be available to serve load during electrical peak loads for the season. Prospective resources are those that could be available but do not meet criteria to be counted as anticipated resources. Refer to the **Data Concepts and Assumptions** section for additional information on Anticipated/Prospective Reserve Margins, anticipated/prospective resources, and RMLs.

Changes from Year to Year

Figure 5 provides the relative change in the forecast ARMs from the 2024 Summer to the 2025 Summer. A significant decline can signal potential operational issues for the upcoming season. Additional details for each assessment area are provided in the Data Concepts and Assumptions and Regional Assessments Dashboards sections.

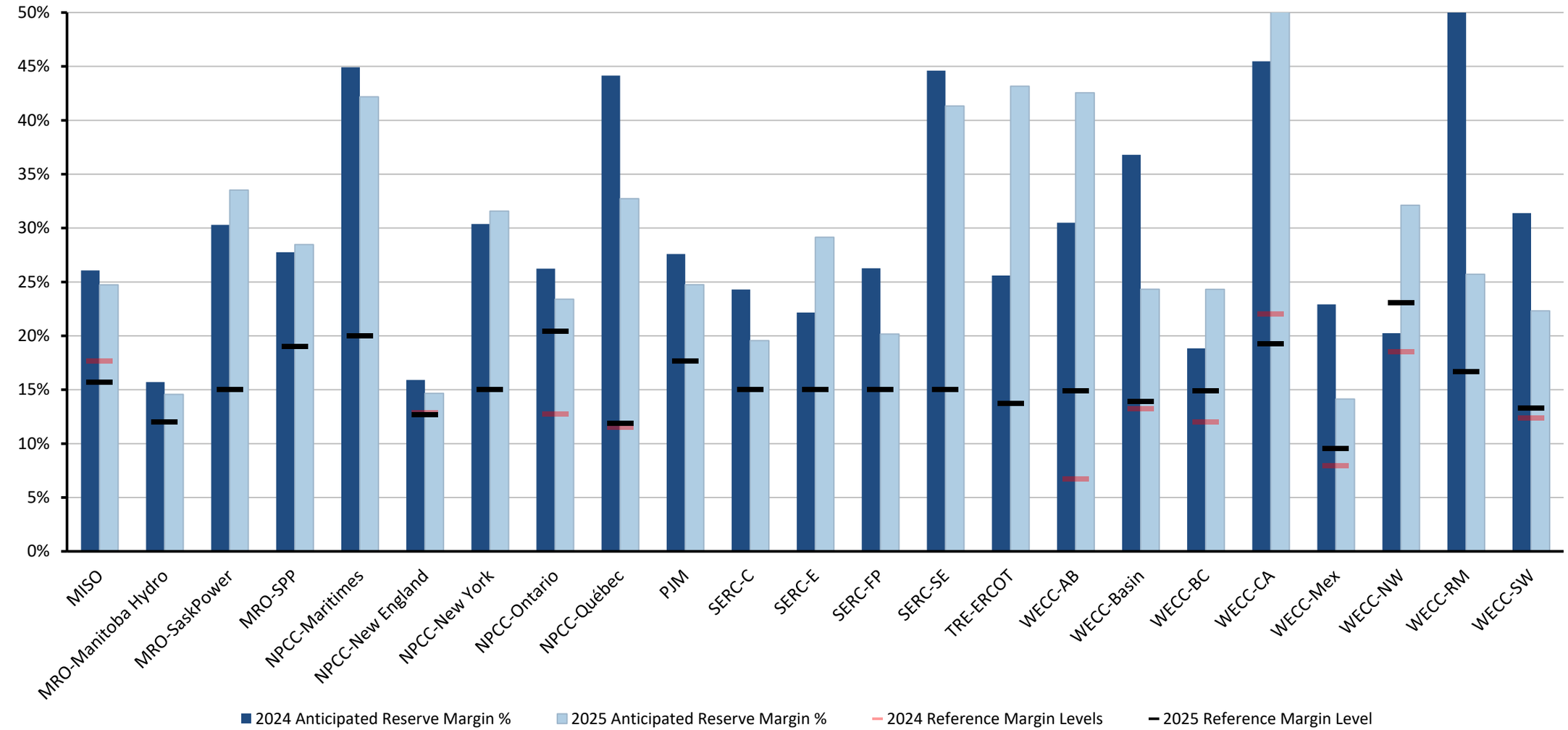


Figure 5: Summer 2024 and Summer 2025 Anticipated Reserve Margins Year-to-Year Change

Note: Yearly trends are not available for new WECC assessment areas in the United States and Baja California, Mexico.

Net Internal Demand

The changes in forecasted net internal demand for each assessment area are shown in Figure 6.[17] Assessment areas develop these forecasts based on historic load and weather information as well as other long-term projections.

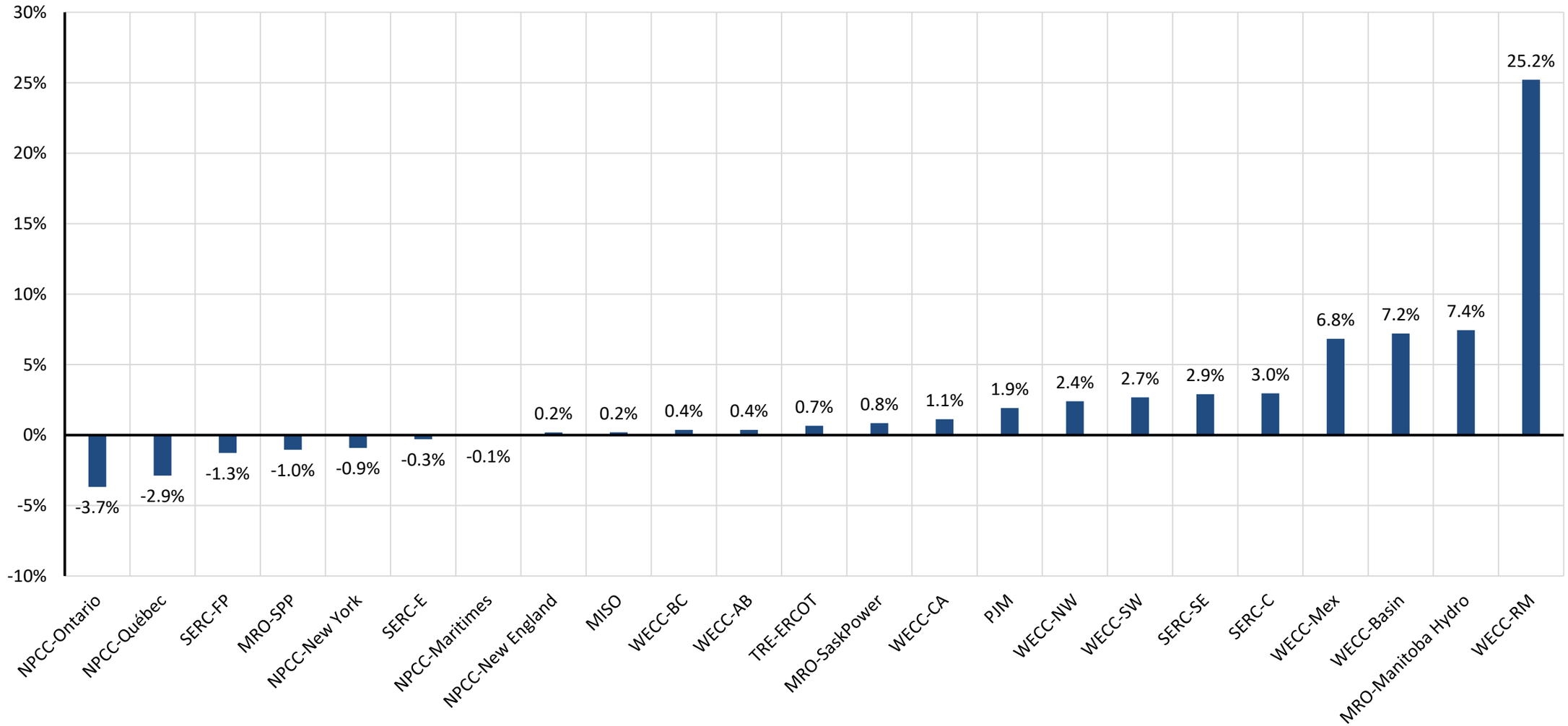


Figure 6: Changes in Net Internal Demand—Summer 2024 Forecast Compared to Summer 2025 Forecast

[17] Changes in modeling and methods are contributing to year-to-year changes in forecasted net internal demand projections in NPCC Maritimes and NPCC Ontario. See assessment area dashboards.

Demand and Resource Tables

Peak demand and supply capacity data—resource adequacy data—for each assessment area are as follows in each table (in alphabetical order).

MISO			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	124,830	125,313	0.4%
Demand Response: Available	8,750	9,004	2.9%
Net Internal Demand	116,079	116,309	0.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	143,866	142,793	-0.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	2,471	2,280	-7.7%
Anticipated Resources	146,337	145,073	-0.9%
Existing-Other Capacity	1,833	1,190	-35.1%
Prospective Resources	148,740	148,543	-0.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.1%	24.7%	-1.3
Prospective Reserve Margin	28.1%	27.7%	-0.4
Reference Margin Level	17.7%	15.7%	-2.0

MRO-Manitoba Hydro			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,143	3,377	7.4%
Demand Response: Available	0	0	-
Net Internal Demand	3,143	3,377	7.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,615	5,583	-0.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-1,978	-1,714	-13.3%
Anticipated Resources	3,637	3,869	6.4%
Existing-Other Capacity	37	21	-42.9%
Prospective Resources	3,674	3,890	5.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	15.7%	14.6%	-1.1
Prospective Reserve Margin	16.9%	15.2%	-1.7
Reference Margin Level	12.0%	12.0%	0.0

MRO-SaskPower			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,590	3,620	0.8%
Demand Response: Available	50	50	0.0%
Net Internal Demand	3,540	3,570	0.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,323	4,477	3.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	290	290	0.0%
Anticipated Resources	4,613	4,767	3.3%
Existing-Other Capacity	0	0	-
Prospective Resources	4,613	4,767	3.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.3%	33.5%	3.2
Prospective Reserve Margin	30.3%	33.5%	3.2
Reference Margin Level	15.0%	15.0%	0.0

MRO-SPP			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	56,316	56,168	-0.3%
Demand Response: Available	979	1,408	43.8%
Net Internal Demand	55,337	54,760	-1.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	70,855	70,549	-0.4%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-157	-201	27.5%
Anticipated Resources	70,698	70,348	-0.5%
Existing-Other Capacity	0	0	-
Prospective Resources	70,151	69,801	-0.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.8%	28.5%	0.7
Prospective Reserve Margin	26.8%	27.5%	0.7
Reference Margin Level	19.0%	19.0%	0.0

NPCC-Maritimes			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,586	3,584	-0.1%
Demand Response: Available	327	327	0.0%
Net Internal Demand	3,259	3,257	-0.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,660	4,348	-6.7%
Tier 1 Planned Capacity	0	220	-
Net Firm Capacity Transfers	63	63	0.0%
Anticipated Resources	4,723	4,631	-1.9%
Existing-Other Capacity	0	0	-
Prospective Resources	4,723	4,631	-1.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	44.9%	42.2%	-2.7
Prospective Reserve Margin	44.9%	42.2%	-2.7
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New York			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	31,541	31,471	-0.2%
Demand Response: Available	1,281	1,487	16.1%
Net Internal Demand	30,260	29,984	-0.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	37,867	37,682	-0.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,585	1,769	11.6%
Anticipated Resources	39,452	39,451	0.0%
Existing-Other Capacity	0	0	-
Prospective Resources	39,452	39,451	0.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.4%	31.6%	1.2
Prospective Reserve Margin	30.4%	31.6%	1.2
Reference Margin Level	15.0%	15.0%	0.0

NPCC-New England			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	25,294	25,202	-0.4%
Demand Response: Available	661	399	-39.6%
Net Internal Demand	24,633	24,803	0.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	27,255	27,054	-0.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,297	1,245	-4.0%
Anticipated Resources	28,552	28,299	-0.9%
Existing-Other Capacity	138	668	384.1%
Prospective Resources	28,690	28,967	1.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	15.9%	14.1%	-1.8
Prospective Reserve Margin	16.5%	16.8%	0.3
Reference Margin Level	12.9%	12.7%	-0.2

NPCC-Ontario			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	22,753	21,955	-3.5%
Demand Response: Available	996	998	0.2%
Net Internal Demand	21,757	20,957	-3.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	26,856	24,760	-7.8%
Tier 1 Planned Capacity	9	413	4568.6%
Net Firm Capacity Transfers	600	689	14.8%
Anticipated Resources	27,465	25,862	-5.8%
Existing-Other Capacity	0	0	-
Prospective Resources	27,465	25,862	-5.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.2%	23.4%	-2.8
Prospective Reserve Margin	26.2%	23.4%	-2.8
Reference Margin Level	12.8%	20.5%	7.7

NPCC-Québec			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	22,922	23,283	1.6%
Demand Response: Available	0	1,020	-
Net Internal Demand	22,922	22,263	-2.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	35,731	32,132	-10.1%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-2,689	-2,582	-4.0%
Anticipated Resources	33,042	29,550	-10.6%
Existing-Other Capacity	0	0	-
Prospective Resources	33,042	29,550	-10.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	44.1%	32.7%	-11.4
Prospective Reserve Margin	44.1%	32.7%	-11.4
Reference Margin Level	11.5%	11.9%	0.4

SERC-Central			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	42,636	42,765	0.3%
Demand Response: Available	1,941	864	-55.5%
Net Internal Demand	40,695	41,900	3.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	47,674	46,949	-1.5%
Tier 1 Planned Capacity	332	592	78.1%
Net Firm Capacity Transfers	2,578	2,554	-0.9%
Anticipated Resources	50,584	50,095	-1.0%
Existing-Other Capacity	2,075	2,475	19.2%
Prospective Resources	52,659	52,570	-0.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.3%	19.6%	-4.7
Prospective Reserve Margin	29.4%	25.5%	-3.9
Reference Margin Level	15.0%	15.0%	0.0

PJM			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	151,247	154,144	1.9%
Demand Response: Available	7,756	7,898	1.8%
Net Internal Demand	143,491	146,246	1.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	183,690	186,638	1.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-607	-4,200	591.9%
Anticipated Resources	183,083	182,438	-0.4%
Existing-Other Capacity	0	0	-
Prospective Resources	182,476	178,238	-2.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.6%	24.7%	-2.8
Prospective Reserve Margin	27.2%	21.9%	-5.3
Reference Margin Level	17.7%	17.7%	0.0

SERC-East			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	43,567	44,015	1.0%
Demand Response: Available	985	1,558	58.2%
Net Internal Demand	42,582	42,457	-0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	51,304	54,665	6.5%
Tier 1 Planned Capacity	122	17	-86.0%
Net Firm Capacity Transfers	593	150	-74.7%
Anticipated Resources	52,019	54,832	5.4%
Existing-Other Capacity	1,131	2,628	132.3%
Prospective Resources	53,150	57,459	8.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.2%	29.1%	7.0
Prospective Reserve Margin	24.8%	35.3%	10.5
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	53,293	52,987	-0.6%
Demand Response: Available	2,824	3,158	11.8%
Net Internal Demand	50,469	49,829	-1.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	63,199	59,395	-6.0%
Tier 1 Planned Capacity	34	102	197.8%
Net Firm Capacity Transfers	491	381	-22.4%
Anticipated Resources	63,724	59,878	-6.0%
Existing-Other Capacity	972	3,482	258.2%
Prospective Resources	64,696	63,360	-2.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.3%	20.2%	-6.1
Prospective Reserve Margin	28.2%	27.2%	-1.0
Reference Margin Level	15.0%	15.0%	0.0

Texas RE-ERCOT			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	84,818	85,151	0.4%
Demand Response: Available	3,496	3,292	-5.8%
Net Internal Demand	81,323	81,859	0.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	99,541	112,321	12.8%
Tier 1 Planned Capacity	2,578	4,854	88.3%
Net Firm Capacity Transfers	20	20	0.0%
Anticipated Resources	102,139	117,195	14.7%
Existing-Other Capacity	0	0	-
Prospective Resources	102,167	117,770	15.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	25.6%	43.2%	17.6
Prospective Reserve Margin	25.6%	43.9%	18.2
Reference Margin Level	13.75%	13.75%	0.0

SERC-Southeast			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	46,021	47,049	2.2%
Demand Response: Available	1,599	1,338	-16.3%
Net Internal Demand	44,422	45,711	2.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	63,693	64,111	0.7%
Tier 1 Planned Capacity	1,738	0	-100.0%
Net Firm Capacity Transfers	-1,192	489	-141.0%
Anticipated Resources	64,238	64,600	0.6%
Existing-Other Capacity	785	1,077	37.1%
Prospective Resources	65,024	65,676	1.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	44.6%	41.3%	-3.3
Prospective Reserve Margin	46.4%	43.7%	-2.7
Reference Margin Level	15.0%	15.0%	0.0

WECC-AB			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	12,201	12,246	0.4%
Demand Response: Available	0	0	-
Net Internal Demand	12,201	12,246	0.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,941	17,176	23.2%
Tier 1 Planned Capacity	1,981	281	-85.8%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	15,922	17,457	9.6%
Existing-Other Capacity	0	0	-
Prospective Resources	15,922	17,457	9.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.5%	42.6%	12.1
Prospective Reserve Margin	30.5%	42.6%	12.1
Reference Margin Level	6.7%	9.0%	2.7

WECC-BC			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	9,275	9,309	0.4%
Demand Response: Available	0	0	-
Net Internal Demand	9,275	9,309	0.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	11,022	11,313	2.6%
Tier 1 Planned Capacity	0	260	-
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	11,022	11,573	5.0%
Existing-Other Capacity	0	0	-
Prospective Resources	11,022	11,573	5.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	18.8%	24.3%	5.5
Prospective Reserve Margin	18.8%	24.3%	5.5
Reference Margin Level	12.0%	14.9%	2.9

WECC-California			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	54,267	54,797	1.0%
Demand Response: Available	816	746	-8.6%
Net Internal Demand	53,451	54,051	1.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	71,564	75,726	5.8%
Tier 1 Planned Capacity	5,998	8,470	41.2%
Net Firm Capacity Transfers	197	598	203.6%
Anticipated Resources	77,759	84,794	9.0%
Existing-Other Capacity	0	0	-
Prospective Resources	77,759	84,794	9.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	45.5%	56.9%	11.4
Prospective Reserve Margin	45.5%	56.9%	11.4
Reference Margin Level	22.0%	19.2%	-2.8

WECC-Southwest			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	34,629	35,321	2.0%
Demand Response: Available	422	199	-52.9%
Net Internal Demand	34,207	35,122	2.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	37,716	40,300	6.9%
Tier 1 Planned Capacity	4,272	1,966	-54.0%
Net Firm Capacity Transfers	2,957	695	-76.5%
Anticipated Resources	44,945	42,961	-4.4%
Existing-Other Capacity	0	0	-
Prospective Resources	44,945	42,961	-4.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	31.4%	22.3%	-9.1
Prospective Reserve Margin	31.4%	22.3%	-9.1
Reference Margin Level	12.4%	13.3%	1.0

WECC-Northwest			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	28,475	29,157	2.4%
Demand Response: Available	30	30	0.0%
Net Internal Demand	28,445	29,127	2.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	33,164	36,388	9.7%
Tier 1 Planned Capacity	201	844	319.9%
Net Firm Capacity Transfers	838	1,249	49.0%
Anticipated Resources	34,203	38,481	12.5%
Existing-Other Capacity	0	0	-
Prospective Resources	34,203	38,481	12.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.2%	32.1%	11.9
Prospective Reserve Margin	20.2%	32.1%	11.9
Reference Margin Level	18.5%	23.1%	4.6

WECC-Basin			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	13,165	14,214	8.0%
Demand Response: Available	485	620	27.8%
Net Internal Demand	12,680	13,594	7.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,534	14,923	10.3%
Tier 1 Planned Capacity	2,436	704	-71.1%
Net Firm Capacity Transfers	1,376	1,274	-7.4%
Anticipated Resources	17,346	16,901	-2.6%
Existing-Other Capacity	0	0	-
Prospective Resources	17,346	16,901	-2.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	36.8%	24.3%	-12.5
Prospective Reserve Margin	36.8%	24.3%	-12.5
Reference Margin Level	13.3%	14.0%	0.7

WECC-Rocky Mountain			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,313	14,098	24.6%
Demand Response: Available	281	284	1.1%
Net Internal Demand	11,032	13,814	25.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	17,345	17,262	-0.5%
Tier 1 Planned Capacity	55	104	89.1%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	17,400	17,366	-0.2%
Existing-Other Capacity	0	0	-
Prospective Resources	17,400	17,366	-0.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	57.7%	25.7%	-32.0
Prospective Reserve Margin	57.7%	25.7%	-32.0
Reference Margin Level	18.0%	16.7%	-1.3

WECC-Mexico			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,529	3,770	6.8%
Demand Response: Available	0	0	-
Net Internal Demand	3,529	3,770	6.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	3,314	4,303	29.8%
Tier 1 Planned Capacity	874	0	-100.0%
Net Firm Capacity Transfers	150	0	-100.0%
Anticipated Resources	4,338	4,303	-0.8%
Existing-Other Capacity	0	0	-
Prospective Resources	4,338	4,303	-0.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.9%	14.1%	-8.8
Prospective Reserve Margin	22.9%	14.1%	-8.8
Reference Margin Level	7.9%	9.6%	1.6

Variable Energy Resource Contributions

Because the electrical output of VERs (e.g., wind, solar PV) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity. The following table shows the capacity contribution of existing wind and solar PV resources at the peak demand hour for each assessment area. Resource contributions are also aggregated by Interconnection and across the entire BPS. For NERC's analysis of risk periods after peak demand (e.g., U.S. assessment areas in WECC), lower contributions of solar PV resources are used because output is diminished during evening periods.

BPS Variable Energy Resources by Assessment Area

	Wind			Solar PV			Hydro			Energy Storage Systems (ESS)		
Assessment Area / Interconnection	Nameplate Wind	Expected Wind	Expected Share of Nameplate (%)	Nameplate Solar PV	Expected Solar PV	Expected Share of Nameplate (%)	Nameplate Hydro	Expected Hydro	Expected Share of Nameplate (%)	Nameplate ESS	Expected ESS	Expected Share of Nameplate (%)
MISO	30,992	6,039	19%	18,246	9,123	50%	1,572	1,467	93%	3,159	3,107	98%
MRO-Manitoba Hydro	259	48	19%	-	-	0%	202	60	30%	-	-	0%
MRO-SaskPower	816	310	38%	30	9	29%	848	686	81%	-	-	0%
NPCC-Maritimes	1,230	314	26%	147	-	0%	1,313	1,313	100%	12	6	50%
NPCC-New England	1,546	142	9%	3,266	1,412	43%	575	175	31%	192	110	57%
NPCC-New York	2,586	446	17%	609	243	40%	976	478	49%	32	17	53%
NPCC-Ontario	4,943	742	15%	478	66	14%	8,862	5,320	60%	-	-	0%
NPCC-Québec	4,024	885	22%	10	-	0%	444	444	100%	-	-	0%
PJM	12,465	1,855	15%	13,731	6,244	45%	2,505	2,505	100%	310	288	93%
SERC-Central	1,324	370	28%	1,810	1,053	58%	4,991	3,418	68%	100	100	100%
SERC-East	-	-	0%	7,097	5,022	71%	3,078	3,008	98%	19	8	41%
SERC-Florida Peninsula	-	-	0%	8,295	5,749	54%	-	-	0%	631	631	100%
SERC-Southeast	-	-	0%	8,507	7,728	91%	3,258	3,308	102%	115	105	92%
SPP	35,613	5,556	16%	1,159	492	42%	114	56	49%	182	41	23%
Texas RE-ERCOT	40,102	9,396	23%	31,473	22,962	73%	572	439	77%	15,291	12,190	80%
WECC-AB	5,712	796	14%	2,174	1,480	68%	894	456	51%	250	235	94%
WECC-BC	747	149	20%	2	-	0%	16,918	10,181	60%	-	-	0%
WECC-Basin	4,859	911	19%	2,648	2,231	84%	2,637	2,022	77%	120	118	98%
WECC-CA	7,836	1,207	15%	25,059	14,756	59%	14,565	6,518	45%	11,459	11,115	97%
WECC-Mexico	300	50	17%	350	227	65%	-	-	0%	-	-	0%
WECC-NW	9,199	3,107	34%	1,349	666	49%	33,068	20,145	61%	11	10	91%
WECC-RM	5,681	1,359	24%	2,523	1,669	66%	3,251	2,446	75%	242	235	97%
WECC-SW	4,848	1,091	23%	9,288	4,293	46%	1,316	845	64%	4,187	3,982	95%
EASTERN INTERCONNECTION	91,773	15,822	17%	67,138	37,886	56%	28,294	21,794	77%	4,752	4,413	93%
QUÉBEC INTERCONNECTION	4,024	885	22%	10	-	0%	444	444	100%	-	-	0%
TEXAS INTERCONNECTION	40,102	9,396	23%	31,473	22,962	73%	572	439	77%	15,291	12,190	80%
WECC INTERCONNECTION	39,182	8,670	22%	43,393	25,322	58%	72,649	42,613	59%	16,269	15,695	96%
All INTERCONNECTIONS	**175,081**	**34,774**	**20%**	**142,014**	**86,170**	**61%**	**101,959**	**65,290**	**64%**	**36,311**	**32,298**	**89%**

Review of 2024 Capacity and Energy Performance

The summer of 2024 was the fourth hottest on record for both the contiguous United States[18] and Canada,[19] with some areas experiencing their hottest summer ever. The result was record electricity demand in the United States as well as in Canada, which was particularly pronounced in the Western Interconnection. While peak demand exceeded normal summer forecasts in most areas, only one area experienced demand that met or exceeded a 90/10 demand scenario as defined in the prior year's *SRA*. In addition, Hurricane Helene, the deadliest Atlantic hurricane to strike the US mainland since 2005, made landfall in Florida in September and led to widespread flooding and power outages from Florida to North Carolina. Helene was one of five hurricanes to impact the US last summer, joining other extreme weather incidents such as drought across the West and wildfires in the Southwest. To manage the challenging grid conditions brought about by heat domes and these other extreme weather events, grid operators across North America used various operating mitigations up to, and including, the issuance of EEAs. No disruptions to the BPS occurred due to inadequate resources. The following section describes actual demand and resource levels in comparison with NERC's *2024 SRA* and summarizes 2024 resource adequacy events.

Eastern Interconnection–Canada and Québec Interconnection

During the June heat wave that extended across the eastern half of the United States and Canada, system operators in Ontario and the Maritimes provinces followed conservative operating protocols and issued energy emergencies. A late-summer heat wave resulted in an energy emergency in Maritimes.

Eastern Interconnection–United States

MISO experienced peak electricity demand during late August. Demand was between the normal and 90/10 summer peak forecast levels. Wind and solar resource output at the time of peak demand were near expectations for summer on-peak contributions. Forced outages of thermal units, however, were lower than expected. On the day prior to MISO's peak demand, operators issued advisories to maximize generation. Similar advisories were issued earlier in the summer, coinciding with above-normal temperatures and periods of high generator forced outages.

In SPP, summer electricity demand peaked in mid-July at a level below normal 50/50 forecasts. Above-normal wind performance and sufficient generator availability contributed to sufficient electricity supplies during peak conditions. In late August, however, SPP operators issued an EEA1 due to high load forecasts, generator outages, and forecasts for low wind output. The period coincided with MISO's peak demand period, making excess supplies for import uncertain. Also in August during a period of high demand and low resource availability, operators issued public appeals for conservation when a 345 kV line outage caused a transmission emergency. During other summer periods, SPP operators responded to forecasts for high demand and low resource conditions with resource advisories intended to maximize available generators.

Like SPP, PJM also experienced peak electricity demand in mid-July and issued an EEA in August. Peak demand in July was near 90/10 forecast levels. Generator outages were below normal at the time of peak demand. In late August, PJM operators issued an EEA1 in expectation of extreme demand.

A period of unseasonably high demand in early summer brought on by high temperatures in the Northeast contributed to an EEA1 in NPCC-New England when a large thermal generator encountered a forced outage. Peak demand in New England occurred in mid-July at a near-normal summer peak demand level. At the time of peak demand, generator outages were below historical averages.

Peak demand in the NPCC-New York area occurred in early July at a level below the normal summer peak demand forecast. Generator outages were below historical levels for peak summer conditions.

[18] US sweltered through its 4th-hottest summer on record – National Oceanic and Atmospheric Administration
[19] Climate Trends and Variations Bulletin – Summer 2024 – Government of Canada

Systems in the U.S. Southeast saw successive heat waves beginning prior to the official start to summer and extending to early fall. Operators in the SERC region used conservative operations and resource advisories to maximize generation and transmission network availability and issued EEAs when warranted by conditions. In some instances, EEAs were issued when generator outages threatened supplies needed for high demand. Peak demand in all assessment areas within the SERC region exceeded normal summer peak demand levels and approached 90/10 demand forecasts.

Texas Interconnection–ERCOT

Peak demand in ERCOT was at or near record levels last summer, as load growth and extreme temperatures contributed to escalating summer electricity needs. Demand peaked in August well above the 90/10 demand forecast. At the time of peak demand, wind generation was below expected levels for peak demand periods, while output from solar generation was near forecasted levels. Forced generator outages were well below historical average levels for peak demand, helping to meet the extreme electricity demand. Unlike the prior summer, ERCOT did not issue any conservation appeals to customers to reduce demand during high-demand periods. New solar generation, battery resources, and some thermal generation additions since Summer 2023 boosted electricity supplies, enabling operators to meet demand records without demand-side management.

Western Interconnection

In July, the Western Interconnection set a new peak demand record of 167,988 MW. Operators in United States and Canada employed procedures throughout summer to manage challenging grid conditions from extended extreme heat and wildfires.

Western Interconnection–Canada

In the province of Alberta, the electric system operator issued an EEA3 in early July as high temperatures contributed to elevated demand that coincided with a forced generator outage. A new summer peak demand record was set in Alberta later in July at 12.2 MW (up from 11.5 GW in summer 2023). Alberta's demand peak was slightly higher than the normal demand peak scenario projected in the spring of last year.

In British Columbia, peak demand reached 9.4 GW (up from 9.2 GW the previous year), also slightly above the normal peak demand that was projected last year.

In both Alberta and British Columbia, peak demand was still below the extreme peak demand scenarios previously projected, which lowered the risk profile of those provinces over Summer 2024.

Western Interconnection–United States

Demand peaked in July in the U.S. Northwest at a level below the normal summer peak demand. During a period of high demand in July, operators at a BA in the U.S. Northwest issued an EEA1 to address forecasted conditions.

The California-Mexico assessment area, which consists of the CAISO, Northern California, and CENACE BAs, experienced system peak electricity demand in early September at a level nearing the 90/10 peak demand forecast. The extreme demand contributed to localized supply concerns and led CAISO to declare a transmission emergency and use conservative operations protocols to posture the system. Despite the extreme demand, operators were able to maintain sufficient supply without resorting to public appeals, as was required in prior summers. New battery resources were instrumental in providing energy to meet high demand during late afternoon and early evenings. Natural-gas-fired generators also performed well and were important to meeting high demand during these same periods. Dry conditions from early summer prompted operators in CA/MX to frequently employ public safety power shutoff (PSPS) procedures beginning in June. Active wildfires led transmission operators to de-energize transmission lines in Northern California and declare transmission emergencies that affected operations across CAISO.

The U.S. Southwest experienced extended heat conditions and demand levels that exceeded 90/10 peak summer forecasts, with peak occurring in early August. Higher-than-expected wind and solar output and low generator outages helped maintain sufficient supplies.

2024 Summer Demand and Generation Summary at Peak Demand							
Assessment Area	Actual Peak Demand[1] (GW)	SRA Peak Demand Scenarios[2] (GW)	Wind – Actual[1] (MW)	Wind – Expected[3] (MW)	Solar – Actual[1] (MW)	Solar – Expected[3] (MW)	Forced Outages Summary[4] (MW)
MISO	118.6	116.1 125.8	4,565	5,599	5,858	4,981	4,412
MRO-Manitoba Hydro	3.6	3.1 3.3	50	48	0	0	290
MRO-SaskPower	3.7	3.5 3.7	170	208	22	6	0
MRO-SPP	54.3	55.3 57.5	10,869	5,876	442	486	6,046
NPCC-Maritimes	3.5	3.3 3.6	428	262	21	-	777
NPCC-New England	24.3	24.6 26.5	174	122	167	1,111	1,496
NPCC-New York	29	30.3 32	130	340	0	53	1,451
NPCC-Ontario	23.9	21.8 23.7	915	720	260	66	1,174
NPCC-Québec	23	22.9 24	2,270	-	0	-	10,500*
PJM	153.1	143.5 156.9	3,366	1,703	2,709	5,694	6,402
SERC-C	42.3	40.7 43.9	312	172	813	996	959
SERC-E	44	42.6 44.7	0	-	3,009	2,405	1,878
SERC-FP	52.4	50.5 53.6	0	-	5,376	5,643	
SERC-SE	44.9	44.4 45.3	0	-	3,507	7,217	1,007
TRE-ERCOT	85.5	81.3 82.3	6,286	9,070	17,566	17,797	3,622
WECC-AB	12.2	12.2 12.7	1,091	666	1,114	786	-**
WECC-BC	9.4	9.3 9.8	257	140	0.94	0	-**

2024 Summer Demand and Generation Summary at Peak Demand							
Assessment Area	**Actual Peak Demand[1] (GW)**	**SRA Peak Demand Scenarios[2] (GW)**	**Wind – Actual[1] (MW)**	**Wind – Expected[3] (MW)**	**Solar – Actual[1] (MW)**	**Solar – Expected[3] (MW)**	**Forced Outages Summary[4] (MW)**
WECC-CA/MX	58.9	53.2 61.6	1,633	1,124	10,112	13,147	921
WECC-NW	59.7	63 69.7	4,694	2,964	6,339	2,595	3,655
WECC-SW	30.8	26.4 28.8	1,179	542	3,357	1,294	2,042
Highlighting Notes	Actual peak demand in the highlighted areas met or exceeded extreme scenario levels.		Actual wind output in highlighted areas was significantly below seasonal forecast.		Actual solar output in highlighted areas was significantly below seasonal forecast.		Actual forced outages above or below forecast by factor of two

Table Notes:
[1] Actual demand, wind, and solar values for the hour of peak demand in U.S. areas were obtained from EIA From 930 data. For areas in Canada, this data was provided to NERC by system operators and utilities.
[2] See NERC *2024 SRA* demand scenarios for each assessment area (pp. 14–33). Values represent the normal summer peak demand forecast and an extreme peak demand forecast that represents a 90/10, or once-per-decade, peak demand. Some areas use other basis for extreme peak demand.
[3] Expected values of wind and solar resources from the *2024 SRA*.
[4] Values from NERC Generator Availability Data System for the 2024 summer hour of peak demand in each assessment area. Highlighted areas had actual forced outages that were more than twice the value for typical forced outage rates used in the 2024 summer risk period scenarios in the *2024 SRA*.
*Values include both maintenance and forced outages.
**Canadian assessment areas report to the NERC Generator Availability Data System on a voluntary basis, which can contribute to the absence of some values in certain assessment areas.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-9

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

Exhibit 42

2019–24 NERC Summer Reliability Assessments

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Summer Reliability Assessment

June 2019

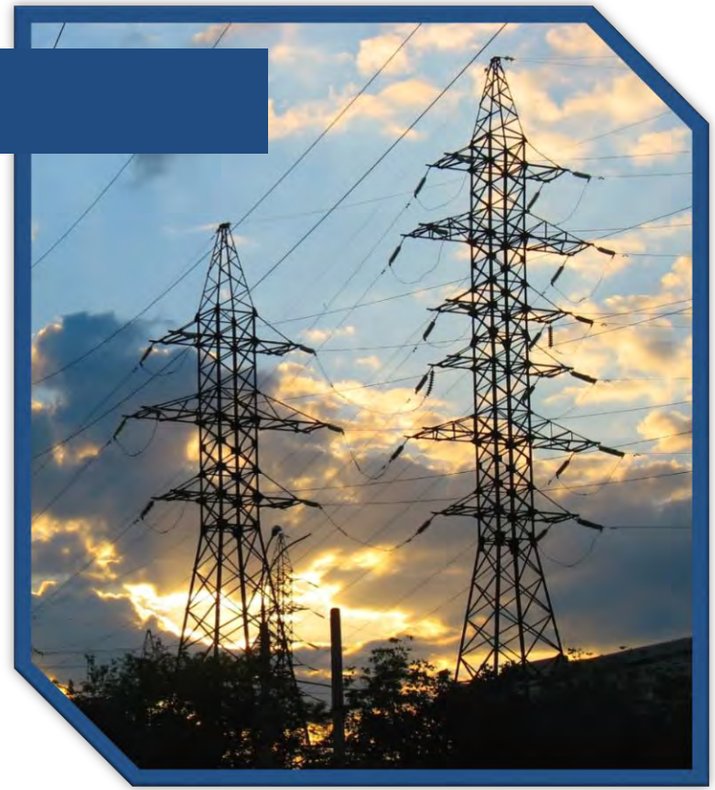


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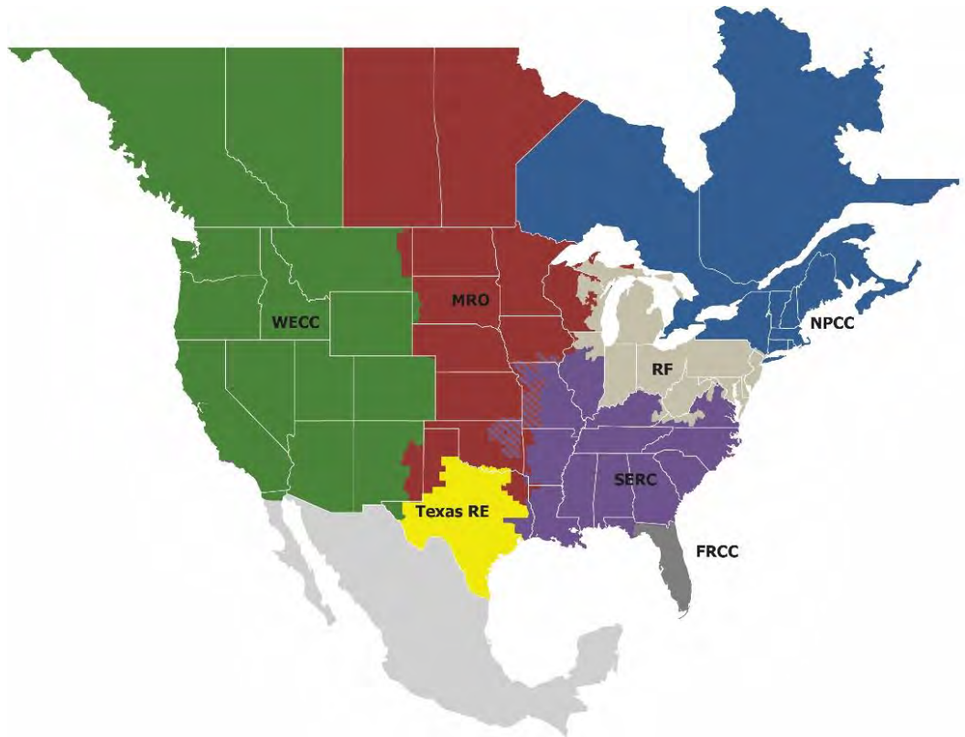
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Preface

The vision for the Electric Reliability Organization (ERO) Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the seven Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid. The North American BPS is divided into seven REs with boundaries as shown in the map below. The multicolored area denotes overlap as some load-serving entities participate in one Region while associated Transmission Owners/Operators participate in another. Refer to the **Data Concepts and Assumptions** section for more information. A map and list of the assessment areas can be found in the **Regional Assessment Dashboards** section.

About this Report

NERC's *2019 Summer Reliability Assessment* identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming summer season. In addition, this assessment presents peak electricity demand and supply changes and highlights any unique regional challenges or expected conditions that might impact the BPS. The reliability assessment process is a coordinated reliability evaluation between the Reliability Assessment Subcommittee (RAS), the Regions, and NERC staff. This report reflects NERC's independent assessment and is intended to inform industry leaders, planners, operators, and regulatory bodies so they are better prepared to take necessary actions to ensure BPS reliability. The report also provides an opportunity for the industry to discuss their plans and preparations to ensure reliability for the upcoming summer period.



Key Findings

NERC's annual *Summer Reliability Assessment* covers the four-month Summer 2019 (June–September) period. This assessment provides an evaluation of whether there is adequate generation and transmission necessary to meet projected summer peak demands. The assessment monitors and identifies potential reliability issues and regional areas of concern that pertain to meeting projected customer demands. The following key findings represent NERC's independent evaluation of electric generation capacity and potential operational concerns that may need to be addressed:

- **ERCOT anticipates Energy Emergency Alerts may be needed to address resource shortfalls during periods of peak demand.** In ERCOT, the Anticipated Reserve Margin remains below the Reference Margin Level of 13.75%. ERCOT's Anticipated Reserve Margin decreased from 10.9% in Summer 2018 to 8.5% for the upcoming summer season. The reduction is caused by higher load growth, a planned generator retirement, and delays in new generation. If resource shortfalls occur, ERCOT anticipates implementing operating mitigations. These measures include importing additional power if available and energy emergency alerts that allow ERCOT to trigger emergency procedures such as voluntary load reduction.
- **Most assessment areas meet or exceed Reference Margin Levels and have sufficient electricity resources for anticipated conditions and more extreme scenarios.** In all areas, with the exception of ERCOT, the Anticipated Reserve Margin meets or surpasses the Reference Margin Level, indicating that planned resources in these areas are adequate to manage loss of load risk under normal conditions.[1] NERC also examined more extreme resource and demand conditions in each assessment area through seasonal risk scenarios. In some assessment areas, extreme summer peak loads and low-probability generator outage scenarios can result in insufficient resources to meet expected operating reserve requirements. In instances where operating reserve requirements are not met, system operators should employ operating procedures and mitigations, which may include demand response, Energy Emergency Alerts that support increased transfers, and other operational mitigations to manage resources and loads.
- **California faces ramping capability concerns.** In the California Independent System Operator (CAISO) area, there is the potential for operational risks at certain times of day as a result of shortages in resources with upward ramping capability. These shortage conditions are more prevalent during late afternoon as solar generation output decreases while system demand is still high. Transfers from neighboring areas may be needed during normal conditions when short on load-following resources capable of ramping up within the CAISO area.
- **Natural-gas-fired electric generation in Southern California will continue to need fuel from natural gas storage facilities for summer reliability.** The natural gas system operator in Southern California assesses that supplies from interstate pipelines alone may not be sufficient to meet the needs of all customers on summer peak load days, leaving electric generators at risk of curtailment. As a result, withdrawals from the Aliso Canyon natural gas storage facility would be necessary to ensure adequate fuel for generators in the Southern California area.
- **Elevated risk for wildfires in Western United States and parts of Canada poses risk to BPS reliability.** Government agencies predict above-normal wildfire risk for summer throughout parts of North America. Operation of the BPS can be impacted in areas where wildfires are active, as well as areas where there is heightened risk of wildfire ignition due to weather and ground conditions. In some areas, pre-season planning includes expanded public safety power shut-off programs in addition to maintenance and operational preparations.

[1] For more information, see the description of the "Reference Margin Level" in the **Data Concepts and Assumptions** section of this report, or refer to NERC's Long-term Reliability Assessment: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2018_12202018.pdf

Resource Adequacy

NERC uses the Anticipated Reserve Margin to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecasted peak load.[2] Large year-to-year changes in anticipated resources or forecasted peak load can greatly impact Planning Reserve Margin calculations. As shown in **Figure 1**, other than Texas RE-ERCOT, all assessment areas have sufficient Anticipated Reserve Margins to meet or exceed their planning Reference Margin Level for the Summer 2019 period. Discussion of significant changes to Anticipated Reserve Margins in the Texas RE-ERCOT and WECC assessment areas are provided in the following sections.

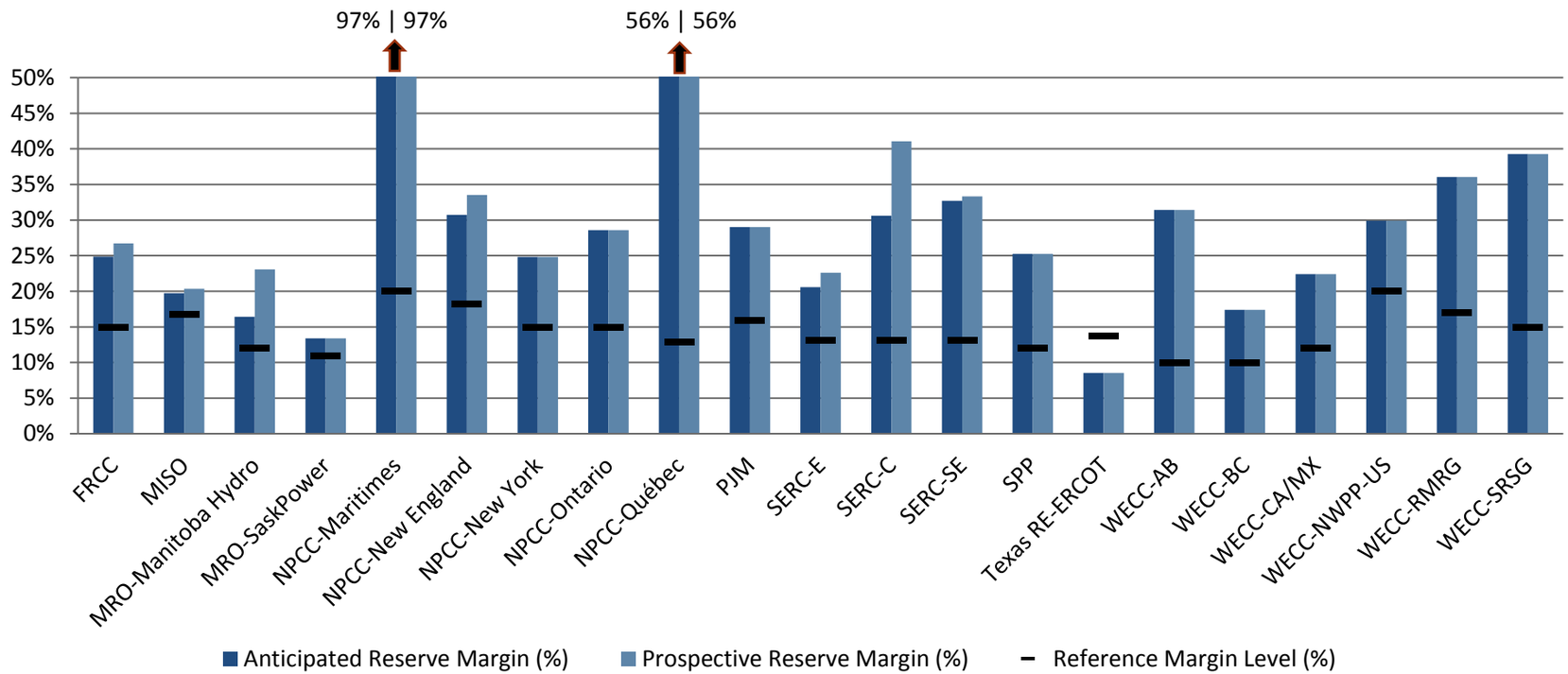


Figure 1: Summer 2019 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[2] Refer to the **Data Concepts and Assumptions** section for additional information on Anticipated Reserve Margins, Anticipated Resources, and Reference Margin Levels.

Changes from Year-to-Year

Understanding the changes from year-to-year is an essential step in assessing an area on a seasonal basis. This understanding can be used to further examine potential operational issues that emerge between reporting years. **Figure 2** provides the relative change from the Summer 2018 to the Summer 2019 period.

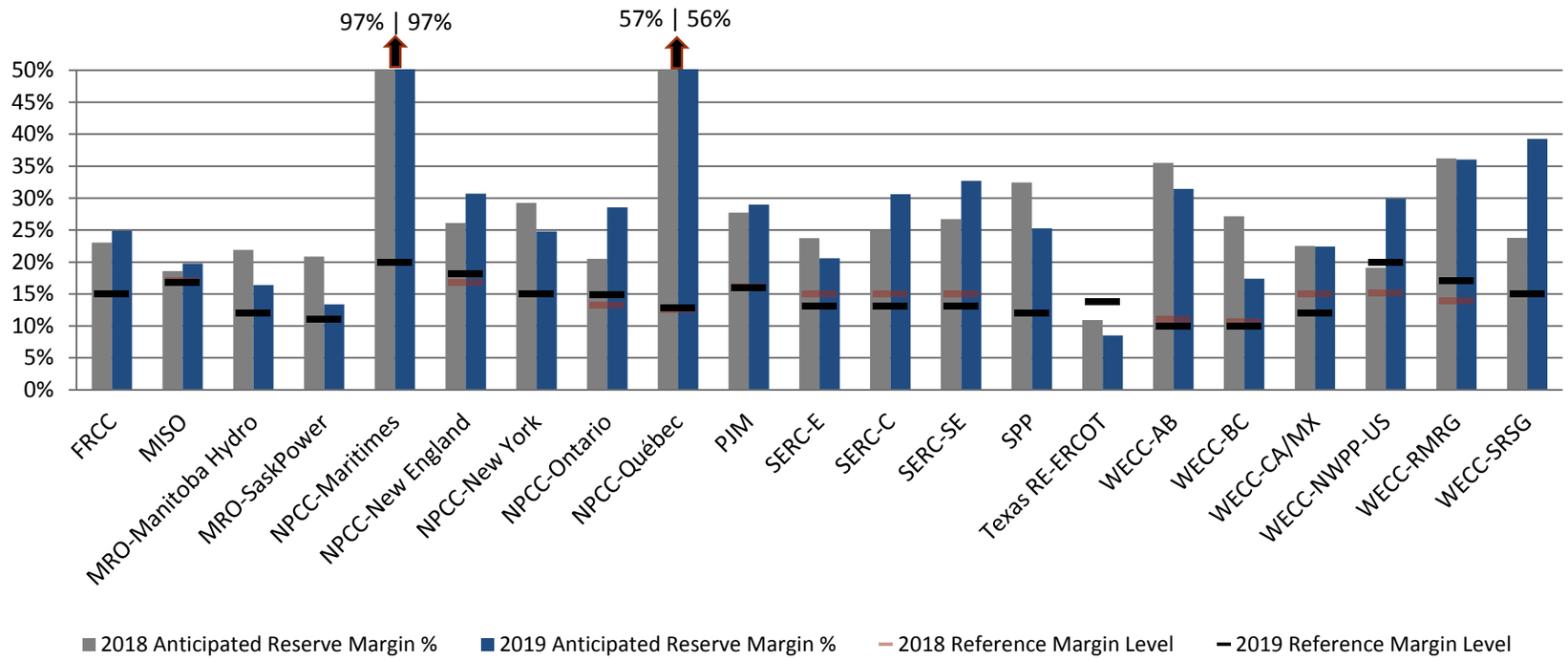


Figure 1: Summer 2018 to Summer 2019 Anticipated Reserve Margins Year-to-Year Change

Risk Highlights for Summer 2019

Tight Reserve Margins in Texas Lead to Operational Challenges

Texas RE-ERCOT enters the Summer 2019 season with a deficit in planning reserves, increasing the likelihood that system operators may need to employ procedures to maintain sufficient operating reserves. In 2018, ERCOT maintained sufficient generation resources through record levels of summer peak demand without resorting to Energy Emergency Alerts. This system performance, due in large part to high levels of generator availability, response to market signals, and unit performance, was notable given the Anticipated Reserve Margin of 10.9%, well-below the Reference Margin Level of 13.75%.[3] For the upcoming summer, growth in anticipated summer peak demand, delays in planned generation projects, and the announced mothballing of a 470 MW coal-fired unit (Gibbons Creek) are expected to push reserve margins still lower, to 8.5%.

Based on ERCOT's summer Seasonal Assessment of Resource Adequacy (SARA) report, released May 8, ERCOT expects that a number of operational tools may be needed this summer to help maintain sufficient operating reserves given the range of resource adequacy scenarios they evaluated.[4] For example, ERCOT system operators can release ancillary services (including load resources that can provide various types of operating reserves based on meeting certain qualification criteria), deploy contracted emergency response service resources, instruct investor-owned utilities to call on their load management and distribution voltage reduction programs, request emergency power across the dc ties, and request support from available switchable generators currently serving non-ERCOT grids.

The SARA report informs ERCOT market participants and operators by deterministically considering the impact of potential variables that may affect the sufficiency of resources for the upcoming season. Historic ranges or expectations for generation maintenance outages, forced outages, and capacity derates during extreme weather conditions are applied deterministically as resource scenarios. The effect of these resource scenarios, along with normal and extreme peak demand scenarios, are examined to determine the potential for scarcity conditions and emergency operating procedure mitigation. **Figure 3** shows a risk assessment developed by NERC using *Summer Reliability Assessment* data and additional data from Texas RE-ERCOT, and the ERCOT 2019 Preliminary SARA report. A description of resource and demand variables is found in **Table 1**.

[3] See ERCOT's 2018 Summer Performance Update: http://www.ercot.com/content/wcm/lists/144927/2018_Summer_Performance_One_Pager_FINAL.pdf
[4] For details see ERCOT's SARA Report: http://www.ercot.com/content/wcm/lists/167022/SARA-FinalSummer2019.xlsx

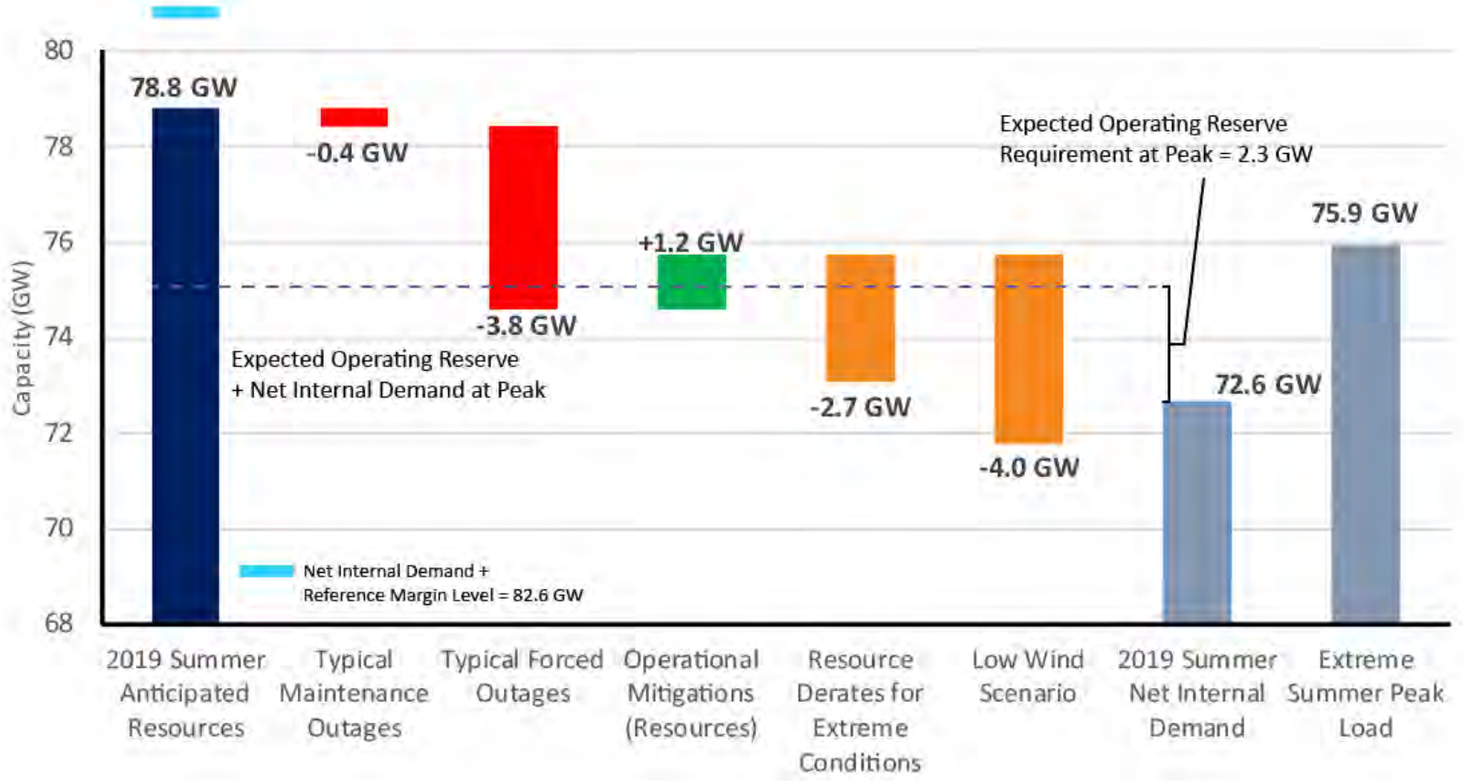


Figure 3: Texas RE-ERCOT Seasonal Risk Assessment

About the Seasonal Risk Assessment The operational risk analysis shown in **Figure 3** provides a deterministic scenario for understanding how various factors affecting resources and demand can combine to impact overall resource adequacy. Adjustments are applied cumulatively to summer anticipated capacity, such as the following:

- Reductions for typical generation outages (maintenance and forced, not already accounted for in summer anticipated resources)
- Additions that represent the quantified capacity from operational tools, if any, that are available during scarcity conditions but have not been accounted for in the SRA reserve margins

Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The effects from low-probability, extreme events are also factored in, through additional resource derates or extreme resource scenarios, and extreme summer peak load conditions. Because the seasonal risk scenario shows the cumulative impact resulting from the occurrence of multiple low-probability events, the overall likelihood of the scenario is very low. An analysis similar to the Texas RE-ERCOT seasonal risk scenario in **Figure 3** can be found for each assessment area in the **Regional Assessment Dashboards** section of this report.

Table 1: Resource and Demand Variables in the ERCOT Seasonal Risk Assessment	
Resource Scenarios	
Typical Maintenance Outages	Typical maintenance outages refer to an estimate of generation resources that will be out for maintenance during peak load conditions. A value of 381 MW was determined based on the historical average of maintenance outages for June through September weekdays, for the last three summer seasons (2016–2018). Planned maintenance outages are generally accounted for in anticipated summer resources, however, this reduction covers additional generator outages granted by operators on a short-term basis as warranted by system conditions.
Typical Forced Outages	Typical forced outages refer to an estimate of generation resources that will experience forced outage during peak load conditions. A value of 3,845 MW is based on historical average of forced outages for June through September weekdays, for the last three summer seasons (2016–2018).
Operational Mitigations	ERCOT assesses that certain operational mitigations, in addition to operating measures accounted for in SRA data and the preliminary SARA Report, can contribute 1,160 MW of additional resources to support maintaining operating reserve requirements. This value is based on three elements: • Switchable generation resources currently serving the Southwest Power Pool (SPP) market that could become available to ERCOT in the event of an energy emergency (total of 489 MW) • Additional imports from the dc tie with the Mexican grid and from SPP beyond what was designated as long-term firm imports (total of 221 MW) • Distribution service providers implementation of distribution voltage reduction (contributing a total of 450 MW)
High Forced Outage Scenario (Low-likelihood Resource Derates)	A low-likelihood, high forced outage scenario is used to analyze the effect of extreme weather-driven generation outages. A capacity adjustment of 2,665 MW from the preliminary SARA report is based on historical forced outages assuming a 90% confidence interval.
Low-Wind Scenario (Low-likelihood)	The low-wind scenario is used to analyze the impact low-likelihood weather conditions that severely reduce output from wind generation resources. A capacity adjustment of 3,960 MW is based on a low wind output scenario included in ERCOT's preliminary summer SARA report. This capacity amount is calculated as the tenth percentile of wind output associated with the 100 highest net load hours (load minus wind output) for the 2015–2018 summer peak load seasons.
Demand Scenarios	
2019 Net Internal Demand	Net internal demand is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour. It is based on historical average weather (i.e., forecasts for a 50/50 distribution).
Extreme Summer Peak Load	A seasonal load adjustment (3,303 MW) is added to 2019 net internal demand based on extreme weather conditions that occurred during Summer 2011. ERCOT compared this value to a statistical extreme load forecast (i.e., a "90/10 load forecast" and found the Summer 2011 peak load to be higher and therefore a more conservative scenario.

ERCOT's tight reserve margins create a potential need to declare an energy emergency alert under many of the peak and extreme conditions studied in the SARA.[5] Once normal operating actions to maintain operating reserves are exhausted, energy emergency alerts can provide system operators with access to additional resources as discussed above that are only available during scarcity conditions. ERCOT also anticipates that higher wholesale market prices during peak demand periods will incentivize power customers to voluntarily reduce load or increase energy output from load-serving generation facilities (such as industrial cogeneration and commercial-sector distributed generation) that can inject power into the ERCOT system. Based on recent ERCOT analysis, the potential amount of this demand and generation response for the upcoming summer is significant but uncertain because the ERCOT market has not experienced summer high prices subsequent to the market design changes implemented in 2012–2014.

Seasonal Risk Assessments for Other Areas

Any area can face resource adequacy risk during peak conditions, even when Planning Reserve Margins exceed Reference Margin Levels. The reasons can be similar: generator scheduled maintenance, forced outages due to normal and more extreme weather conditions and loads, as well as low-likelihood conditions that affect generation resource performance or unit availability including constrained fuel supplies. The **Regional Assessment Dashboards** section in this report includes a seasonal risk scenario for each area that illustrates variables in resources and load, and where appropriate, the potential effects that operating actions can have to mitigate shortfalls in operating reserves.

CAISO Faces Concerns with Ramping Capability, Natural Gas Supply

For Summer 2019, the risk of resource shortfalls in CAISO is lower than last summer. However, there is increased risk of insufficient ramping capability during peak conditions. Conditions for hydroelectric generation are well above normal due to replenishment of reservoirs and mountain snow during the preceding winter, greatly reducing the potential for operating reserve shortfalls. However, the *2019 Summer Loads and Resources Assessment* highlights concerns with shortages in load-following resources capable of ramping up, particularly during late afternoon when solar generation output decreases while system demand is still high.[6] Increasing penetrations of solar resources and the retirements of dispatchable generation units has contributed to a shortage of ramping resources. When faced with such shortages, operators will need to call upon neighbors for imports to maintain system frequency. Should extreme temperatures extend over a large area to the point where neighbors lack surplus energy, load could be at risk from a shortage in ramping capability.

The impacts to electric generation resulting from operating restrictions at the Aliso Canyon natural gas storage facility remain an item of focus for electric reliability within the Western Interconnection. Withdrawals from natural gas storage facilities were at a high level during Winter 2018–2019 due to colder than average winter temperatures, resulting in below average storage levels approaching the Summer 2019 season. The Southern California Gas Company (SoCalGas) forecasts that it will be able to meet the forecasted peak day demand under a "best case" supply assumption even without supply from Aliso Canyon.[7] However, under a worst case supply assumption, supply from Aliso Canyon will be necessary to meet that forecasted peak day demand. Should operating restrictions result in natural gas supply curtailments that affect electric generation in the Southern California area, mitigation procedures that have been in place since 2016 can be used to maintain BPS reliability.

In addition to managing natural gas storage to meet summer demand, SoCalGas also uses summer months to begin increasing storage levels in preparation for peak winter months. Winter storage levels can be impacted in some scenarios that involve reduced natural gas storage receipts due to supply infrastructure servicing.

[5] A description of Energy Emergency Alerts and processes for communicating and coordination during operating emergencies is contained in NERC Reliability Standard *EOP-011-1 – Emergency Operations* available at the following link: https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-011-1.pdf

[6] See CAISO 2019 Summer Loads and Resources Assessment here: http://www.caiso.com/Documents/2019SummerLoadsandResourcesAssessment.pdf

[7] See Southern California Gas Company (SoCalGas) *2019 Summer Technical Assessment*, April 4, 2019, available at the link below. At the time of drafting the NERC 2019 SRA, the California Public Utilities Commission (CPUC) summer technical assessment for Aliso Canyon had not been released. The CPUC assessment is expected to provide the most current and comprehensive information, including potential impacts to the BPS in Southern California.
http://cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2019/SoCalGas%20Summer%202019%20Technical%20Assessment%20040219.pdf

Mitigation Operating Plans

Should CAISO system operating conditions go into the emergency stages, such as operating reserve shortfalls where non-spinning reserve requirement cannot be maintained or spinning reserve is depleted and operating reserve falls below minimum requirement, the following mitigation operating plan will be implemented to minimize loss of load in the CAISO Balancing Authority area:

- Use the Flex Alert program, signaling that the CAISO expects high peak load condition. This program has been proven to reduce peak load in the CAISO Balancing Authority area.
- Use the CAISO Restricted Maintenance program. This program is intended to reduce potential forced outages, therefore, minimizing forced outage rate during the high peak load condition.
- Perform manual post day-ahead unit commitment and exceptional dispatch of resources under contract to ensure the ability to serve load and meet flexible ramping capability requirements.
- Perform manual exceptional dispatch of intertie resources that have resource adequacy obligation to serve CAISO load.
- Use the CAISO Alert/Warning/Emergency (AWE) program.
- Use the demand response program including the Reliability Demand Response Resources (RDRR) under the "Warning" stage.
- Perform manual exceptional dispatch of physically available resources that are not under capacity contract.

Wildfire Risk and Potential for Impacts to the BPS

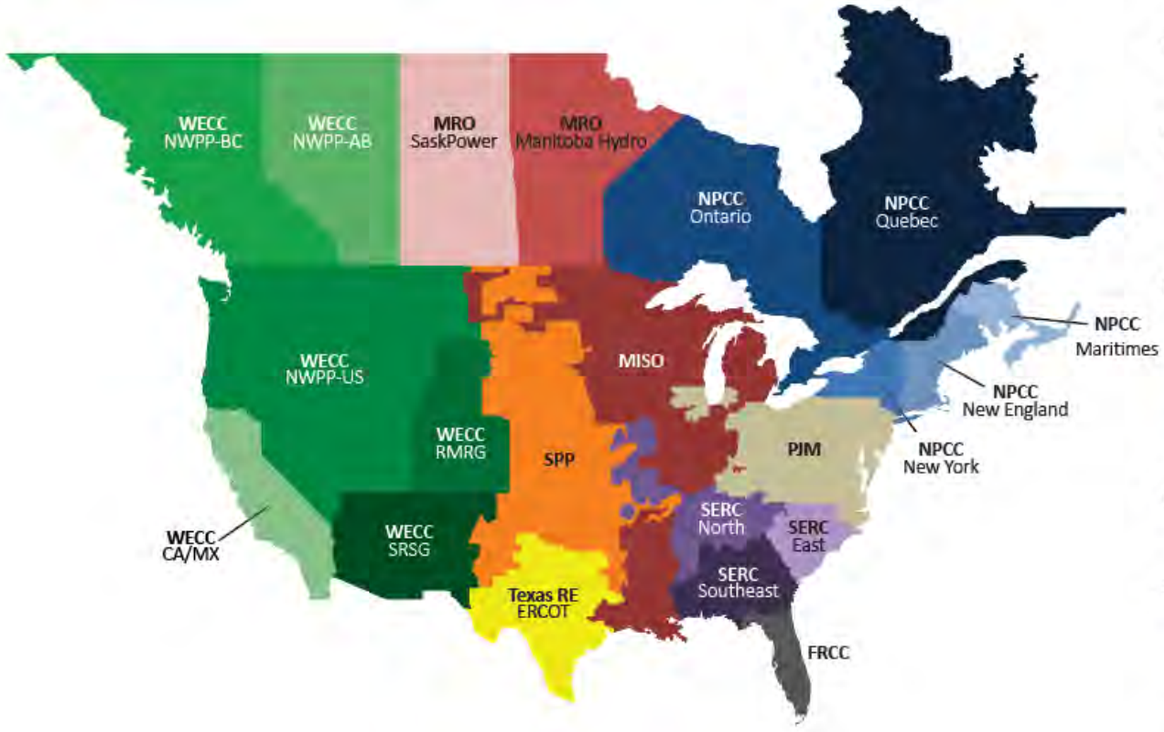
Government agencies predict above-normal wildfire risk for the summer throughout parts of North America. The National Interagency Fire Center, Natural Resources Canada, and National Meteorological Service in Mexico published a three-month seasonal potential wildfire outlook (April-June), which predicts above normal wildfire potential for California and the Pacific Northwest (Western Oregon and Washington), Western Alberta, British Columbia, and Northern Mexico.[8]

Operation of the BPS can be impacted in areas where wildfires are active, as well as areas where there is heightened risk of wildfire ignition due to weather and ground conditions. With the widely dispersed nature of the transmission system in western parts of North America, outages due to wildfires are generally not widespread. Furthermore, utilities are enhancing wildfire prevention planning in California and other areas to address increased risk. In some cases, plans could include expanding power shut-off programs in high fire-risk areas. When conditions warrant implementing these plans, power lines, including transmission-level lines, may be preemptively deenergized in high fire-risk areas to prevent wildfire ignitions. Other activities include implementing enhanced vegetation management, equipment inspections, system hardening, and added situational awareness measures.

[8] See the *North American Seasonal Fire Outlook*, issued May 10, 2019: https://www.predictiveservices.nifc.gov/outlooks/NA_Outlook.pdf

Regional Assessment Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the seven Regional Entities on an assessment area basis.



FRCC – Florida Reliability Coordinating Council
- FRCC

MRO – Midwest Reliability Organization
- MISO
- MRO-Manitoba Hydro
- MRO-SaskPower

NPCC – Northeast Power Coordinating Council
- NPCC-Maritimes
- NPCC-New England
- NPCC-New York
- NPCC-Ontario
- NPCC-Québec

RF – ReliabilityFirst
- PJM

SERC – SERC Reliability Corporation
- SERC-East
- SERC-North
- SERC-Southeast

SPP – Southwest Power Pool
- SPP

Texas RE – Texas Reliability Entity
- Texas RE-ERCOT

WECC
- WECC-CA/MX
- WECC-NWPP-AB
- WECC-NWPP-BC
- WECC-NWPP-US
- WECC-RMRG
- WECC-SRSG

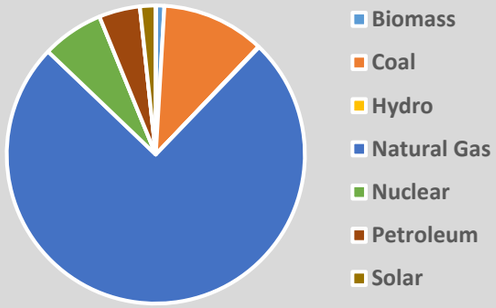


FRCC

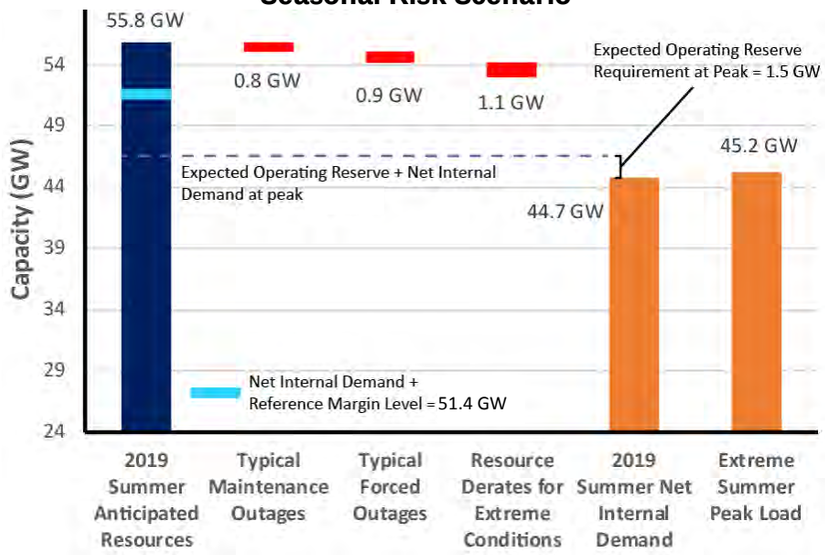
The Florida Reliability Coordinating Council's (FRCC) membership includes 32 Regional Entity Division members and 22 Member Services Division members composed of investor-owned utilities, cooperatives, municipal utilities, power marketers, and independent power producers.

FRCC is divided into 10 Balancing Authorities with 36 registered entities (including both members and non-members) performing the functions identified in the NERC Reliability Functional Model and defined in the NERC Reliability Standards. The Region contains a population of more than 16 million people and has a geographic coverage of about 50,000 square miles across Florida.

On-Peak Capacity: Generation Mix



Seasonal Risk Scenario



The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels, with adjustments for normal and extreme conditions. FRCC determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized below. See the **Seasonal Risk Scenario Chart Description** for more information about this chart.

Risk Scenario Summary

Observation:
Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** 90/10 forecast
- **Outages:** Historical average MW during summer season
- **Extreme Derates:** 3% capacity derate applied on all natural gas unit capacity

FRCC Resource Adequacy Data

Demand, Resource, and Reserve Margin	2018 SRA	2019 SRA	2018 vs. 2019 SRA
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	47,495	47,670	0.4%
Demand Response: Available	2,957	2,951	-0.2%
Net Internal Demand	44,538	44,719	0.4%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	53,010	52,163	-1.6%
Tier 1 Planned Capacity	321.6	2,221	> 100%
Net Firm Capacity Transfers	1,477	1,456	-1.4%
Anticipated Resources	54,809	55,840	1.9%
Existing-Other Capacity	763.9	834	9.2%
Prospective Resources	55,573	56,674	2.0%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	23.1%	24.9%	1.8
Prospective Reserve Margin	24.8%	26.7%	1.9
Reference Margin Level	15.0%	15.0%	0.0

Highlights

- FRCC has not identified any emerging reliability issues that are expected to impact reliability in the FRCC Region for the upcoming 2019 summer season.
- The BPS within the FRCC Region is expected to perform reliably for the anticipated 2019 summer season condition.
- On July 1, 2019, Regional Entity responsibilities will shift from FRCC to SERC for entities in Florida. FRCC will continue to provide member services and will remain a NERC assessment area.

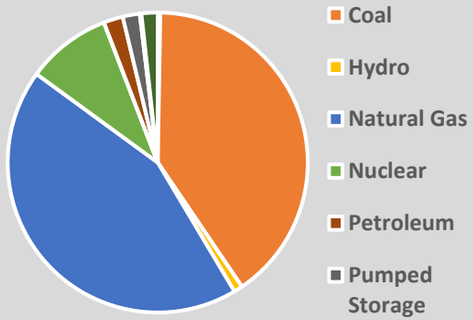


MISO

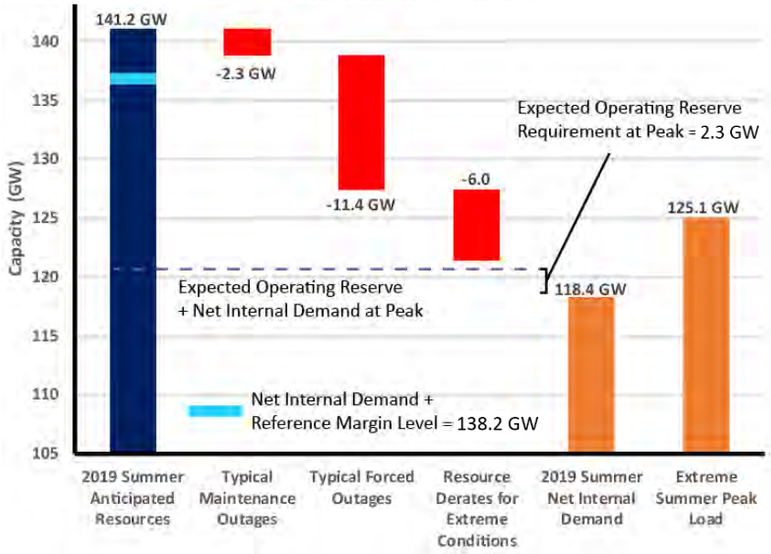
The Midcontinent Independent System Operator, Inc. (MISO) is a not-for-profit, member-based organization administering wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency.

MISO manages energy, reliability, and operating reserve markets that consist of 36 local Balancing Authorities and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three NERC Regions, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

On-Peak Capacity: Generation Mix



Seasonal Risk Scenario



The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels, with adjustments for normal and extreme conditions. MISO determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized below. See the **Seasonal Risk Scenario Chart Description** for more information about this chart.

Risk Scenario Summary

Observation:

Resources meet operating reserve requirements under normal peak load scenario. Extreme summer peak load and outage conditions could result in the need to employ operating mitigation to manage resource shortfall.

Scenario Assumptions

- **Extreme Peak Load:** 90/10 forecast
- **Outages:** Average from highest peak hour over the past five summers
- **Extreme Derates:** Additional outages based on analysis of past five years summer peak outages

MISO Resource Adequacy Data

Demand, Resource, and Reserve Margin	2018 SRA	2019 SRA	2018 vs. 2019 SRA
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	124,704	124,744	0.0%
Demand Response: Available	5,990	6,385	6.6%
Net Internal Demand	118,714	118,359	-0.3%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	141,425	139,220	-1.6%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	-8	1,955	-
Anticipated Resources	141,417	141,175	-0.2%
Existing-Other Capacity	1,104	591	-46.5%
Prospective Resources	142,521	141,766	-0.5%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	19.1%	19.3%	0.2
Prospective Reserve Margin	20.1%	19.8%	-0.3
Reference Margin Level	17.1%	16.8%	-0.3

Highlights

- MISO does not anticipate reliability issues during the upcoming season for typical resource outages and load. MISO studied the summer system reliability under various resource outage and load scenarios. MISO held a summer readiness workshop with its members on April 23, 2019, to prepare for summer operations.
- MISO worked with entities in the SERC Region to develop an operating procedure to address potential issues that may result from high MISO north and south transfers. These transfers between MISO operating areas can cause entities in other Regions to experience loop flows that can impact system operations.
- MISO's Load Modifying Resource (LMR) FERC filing is expected to provide MISO's operators with greater access to the existing capabilities of LMRs. Enhancements include requiring LMR units to operate to their existing capability and added processes to schedule LMRs in anticipation of emergency conditions.

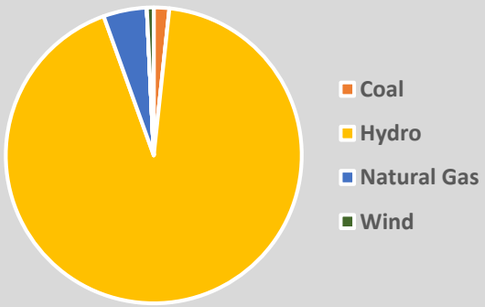


MRO-Manitoba Hydro

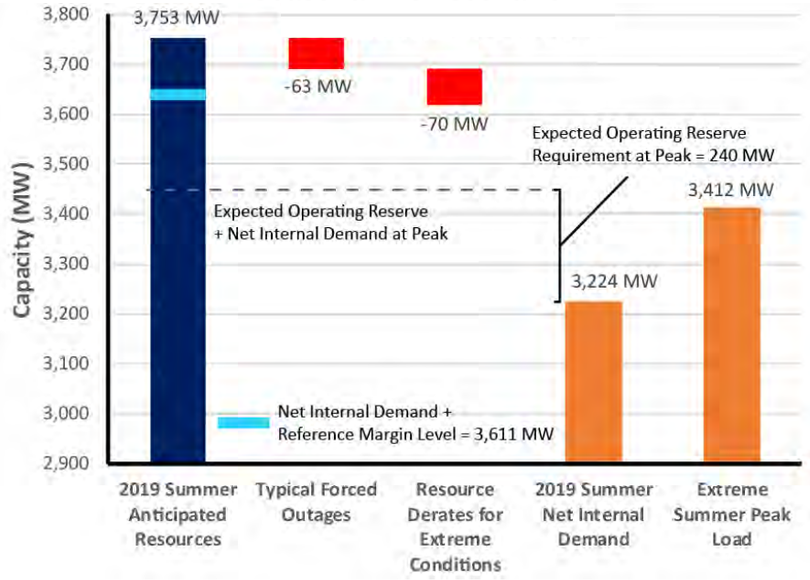
Manitoba Hydro is a provincial crown corporation that provides electricity to about 573,000 customers throughout Manitoba and natural gas service to about 279,000 customers in various communities throughout Southern Manitoba. The Province of Manitoba has a population of about 1.3 million people in an area of 250,946 square miles.

Manitoba Hydro is winter peaking. No change in the footprint area is expected during the assessment period. Manitoba Hydro is its own Planning Coordinator and Balancing Authority. Manitoba Hydro is a coordinating member of MISO. MISO is the Reliability Coordinator for Manitoba Hydro.

On-peak Capacity: Generation Mix



Seasonal Risk Scenario



The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels, with adjustments for normal and extreme conditions. MRO-Manitoba determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized below. See the **Seasonal Risk Scenario Chart Description** for more information about this chart.

Risk Scenario Summary

Observation:
Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** All-time highest peak load
- **Outages:** Based on historical operating experience
- **Extreme Derates:** Thermal units derated for extreme temperature where appropriate

MRO-Manitoba Hydro Resource Adequacy Data

Demand, Resource, and Reserve Margin	2018 SRA	2019 SRA	2018 vs. 2019 SRA
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	3,237	3,224	-0.4%
Demand Response: Available	0	0	0.0%
Net Internal Demand	3,237	3,224	-0.4%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	5,288	5,161	-2.4%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	-1,342	-1,408	4.9%
Anticipated Resources	3,946	3,753	-4.9%
Existing-Other Capacity	122.3	215	75.4%
Prospective Resources	4,068	3,968	-2.5%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	21.9%	16.4%	-5.5
Prospective Reserve Margin	25.7%	23.1%	-2.6
Reference Margin Level	12.0%	12.0%	0.0

Highlights

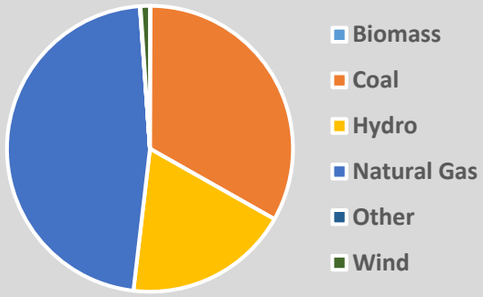
- There are no emerging reliability issues for the upcoming season in the Manitoba Hydro assessment area.
- Manitoba Hydro completed and commissioned the third HVdc line and placed it into service in July 2018. This addition significantly increased the system reliability by introducing an additional corridor for transmission of power generated by the bulk of Manitoba Hydro's generation in northern Manitoba to Southern Manitoba where the majority of the load is located.
- Reservoirs are at adequate storage levels and capable of supplying through design drought conditions.



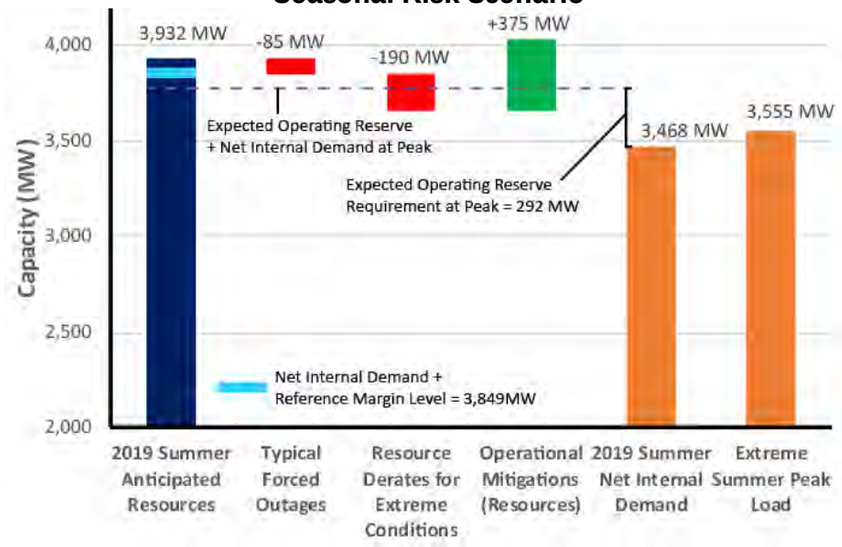
MRO-SaskPower

Saskatchewan is a province of Canada and comprises a geographic area of 651,900 square kilometers (251,700 square miles) with approximately 1.1 million people. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the Planning Coordinator and Reliability Coordinator for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan Bulk Electric System and its interconnections.

On-Peak Capacity: Generation Mix



Seasonal Risk Scenario



The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels, with adjustments for normal and extreme conditions. MRO-SaskPower determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized below. See the **Seasonal Risk Scenario Chart Description** for more information about this chart.

Risk Scenario Summary

Observation:

Resources meet operating reserve requirements under typical scenarios. Operating mitigations would be needed to meet reserve requirements in extreme outages and peak loads.

Scenario Assumptions

- **Extreme Peak Load:** Peak load with peak lighting and industrial demand
- **Maintenance Outages:** Estimated based on average maintenance outages in Summer 2018
- **Forced Outages:** Estimated using SaskPower model
- **Extreme Derates:** Derate on natural gas units based on historic data and manufacturer data

MRO-SaskPower Resource Adequacy Data

Demand, Resource, and Reserve Margin	2018 SRA	2019 SRA	2018 vs. 2019 SRA
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	3,426	3,553	3.7%
Demand Response: Available	85	85	0.0%
Net Internal Demand	3,341	3,468	3.8%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	4,013	3,907	-2.6%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	25	25	0.0%
Anticipated Resources	4,038	3,932	-2.6%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	4,038	3,932	-2.6%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	20.8%	13.4%	-7.4
Prospective Reserve Margin	20.8%	13.4%	-7.4
Reference Margin Level	11.0%	11.0%	0.0

Highlights

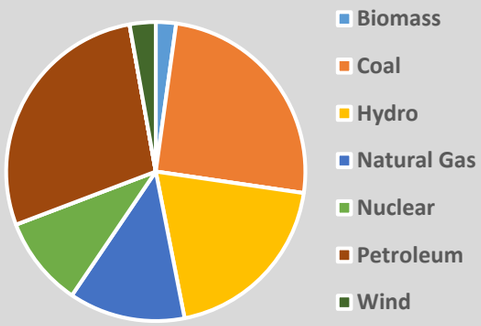
- No reliability issues are expected for the upcoming summer season. Saskatchewan experiences peak load in winter. Reserve margin is expected to be higher than the reference reserve margin for the upcoming summer
- SaskPower conducts an annual summer season joint operating study with Manitoba Hydro, with inputs from Basin Electric Power Cooperative (North Dakota), and prepares operating guidelines for identified issues.
- In case of extreme load conditions combined with large generation forced outages, SaskPower would use available demand response programs, short term power transfers from neighboring utilities, and short term load interruptions.



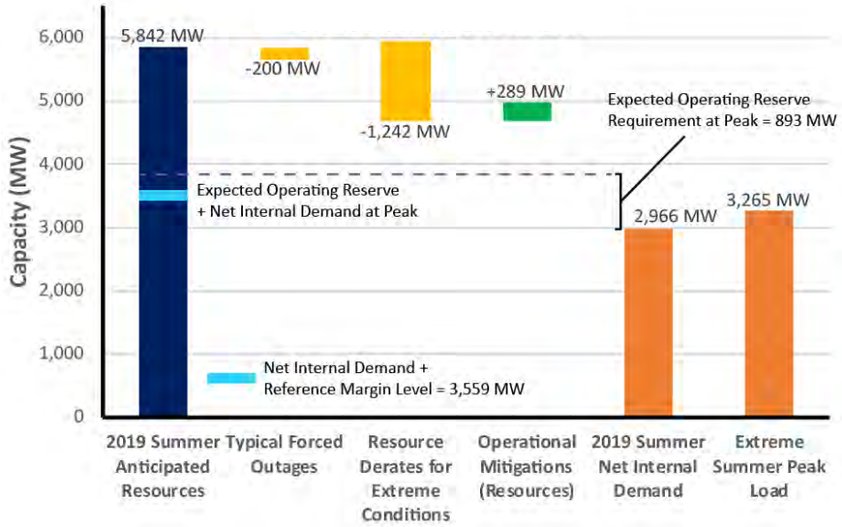
NPCC-Maritimes

The Maritimes assessment area is a winter-peaking NPCC subregion that contains two Balancing Authorities. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, and Prince Edward Island, and the northern portion of Maine, which is radially connected to the New Brunswick power system. The area covers 58,000 square miles with a total population of 1.9 million people.

On-Peak Capacity: Generation Mix



Seasonal Risk Scenario



NPCC-Maritimes Resource Adequacy Data

Demand, Resource, and Reserve Margin	2018 SRA	2019 SRA	2018 vs. 2019 SRA
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	3,235	3,255	0.6%
Demand Response: Available	300	289	-3.7%
Net Internal Demand	2,935	2,966	1.1%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	5,828	5,842	0.2%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	0	0	0.0%
Anticipated Resources	5,828	5,842	0.2%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	5,828	5,842	0.2%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	98.6%	97.0%	-1.6
Prospective Reserve Margin	98.6%	97.0%	-1.6
Reference Margin Level	20.0%	20.0%	0.0

The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels, with adjustments for normal and extreme conditions. NPCC-Maritimes determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized below. See the **Seasonal Risk Scenario Chart Description** for more information about this chart.

Risk Scenario Summary

Observation:
Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** 90/10 forecast
- **Outages:** Based on historical operating experience
- **Extreme Derates:** An extreme, low-likelihood scenario is used whereby thermal units are derated for extreme temperature and all wind unit capacity is unavailable

Highlights

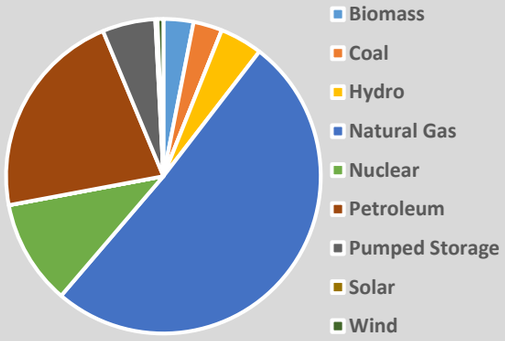
- The Maritimes area has not identified any operational issues that are expected to impact system reliability. If an event were to occur, there are emergency operations and planning procedures in place. All of the area's declared firm capacity is expected to be operational for the summer operating period.
- As part of the planning process, dual-fueled units will have sufficient supplies of heavy fuel oil (HFO) on-site to enable sustained operation in the event of natural gas supply interruptions.



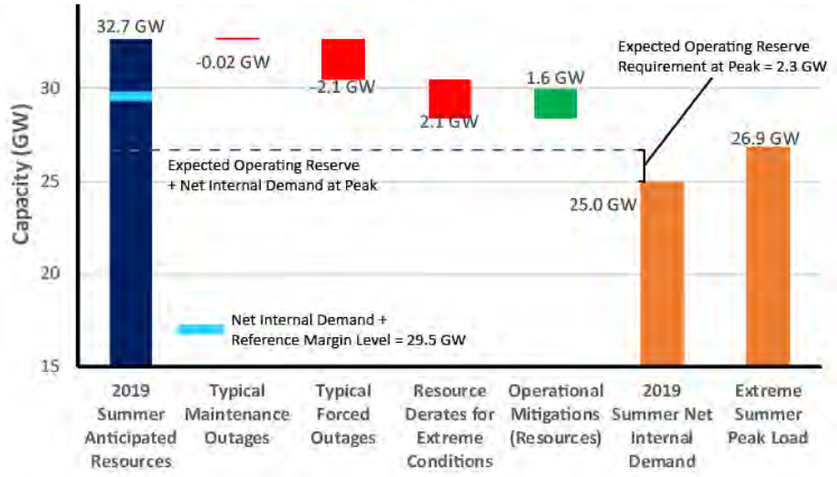
NPCC-New England

ISO New England (ISO-NE) Inc. is a Regional Transmission Organization that serves Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. It is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, and it also administers the area's wholesale electricity markets and manages the comprehensive planning of the regional BPS. The New England regional electric power system serves approximately 14.5 million people over 68,000 square miles.

On-Peak Capacity: Generation Mix



Seasonal Risk Scenario



The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels, with adjustments for normal and extreme conditions. NPCC-New England determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized below. See the **Seasonal Risk Scenario Chart Description** for more information about this chart.

Risk Scenario Summary

Observation:

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** 90/10 Forecast
- **Outages:** Near-zero MW due to summer peaking area
- **Extreme Derates:** Based on historical forced outages and any additional reductions for fuel-supply risk
- **Operating Mitigations:** Based on ISO-NE operating procedures

NPCC-New England Resource Adequacy Data

Demand, Resource, and Reserve Margin	2018 SRA	2019 SRA	2018 vs. 2019 SRA
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	25,729	25,323	-1.6%
Demand Response: Available	408	340	-16.7%
Net Internal Demand	25,321	24,983	-1.3%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	30,460	30,144	-1.0%
Tier 1 Planned Capacity	0	1,185	-
Net Firm Capacity Transfers	1,468	1,328	-9.5%
Anticipated Resources	31,928	32,657	2.3%
Existing-Other Capacity	421	704	67.2%
Prospective Resources	32,349	33,361	3.1%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	26.1%	30.7%	4.6
Prospective Reserve Margin	27.8%	33.5%	5.7
Reference Margin Level	16.8%	18.3%	1.5

Highlights

- The New England area expects to have sufficient resources to meet the 2019 summer peak demand forecast of 25,323 MW, with a corresponding projected net margin of 7,674 MW after accounting for demand response resources. This net margin is a 1,067 MW increase from the 2018 Anticipated Reserve Margin forecast. The increase can be largely attributed to new generation becoming available prior to the 2019 summer and a decrease in forecasted net demand.
- The upcoming retirement of the 674 MW Pilgrim nuclear unit is offset by additions in excess of 1,000 MW of combined cycle and combustion gas turbine generating units.
- The 2019 summer demand forecast is 406 MW (1.6%) lower than the 2018 summer forecast and takes into account the demand reductions associated with energy efficiency and behind-the-meter photovoltaic (BTM-PV) systems.
- The 18.3% Reference Margin Level is based on New England's net installed capacity requirement for the 2019–2020 commitment period, which was approved by FERC.

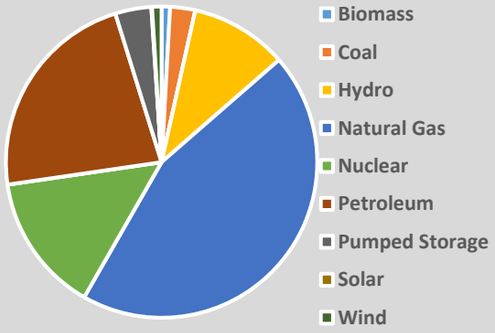


NPCC-New York

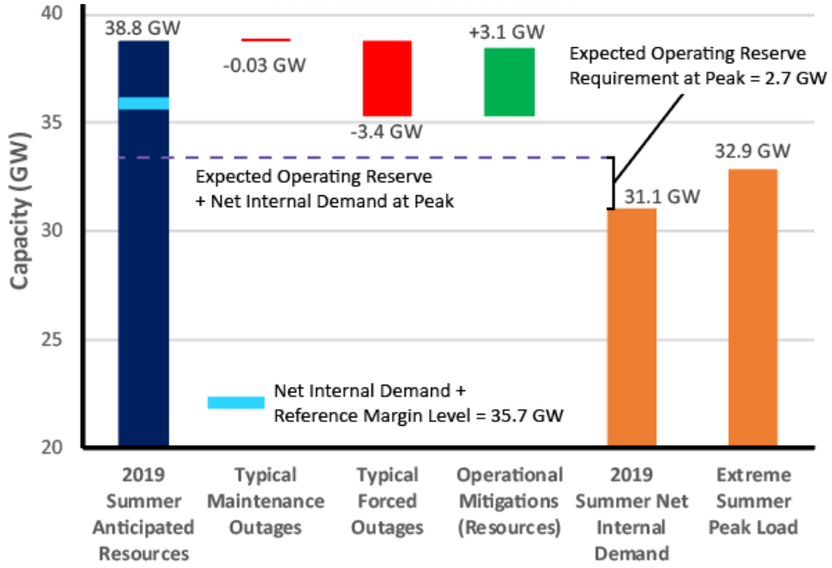
The New York Independent System Operator (NYISO) is the only Balancing Authority (NYBA) within the state of New York. NYISO is a single-state ISO that was formed as the successor to the New York Power Pool—a consortium of the eight IOUs—in 1999. NYISO manages the New York State transmission grid that encompasses approximately 11,000 miles of transmission lines, more than 47,000 square miles, and serving the electric needs of 19.5 million people. New York experienced its all-time peak load of 33,956 MW in the Summer 2013.

The NERC Reference Margin Level is 15%. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. However, New York requires load serving entities to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). NYSRC approved the 2019–2020 IRM at 17%.

On-Peak Capacity: Generation Mix



Seasonal Risk Scenario



The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels, with adjustments for normal and extreme conditions. NPCC-New York determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized below. See the **Seasonal Risk Scenario Chart Description** for more information about this chart.

Risk Scenario Summary

Observation:
Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** 90/10 forecast
- **Extreme Derates:** Near-zero MW due to summer peaking area
- **Forced Outages:** Based on five-year average performance
- **Operational Mitigation:** Based on operational/emergency procedures in NYISO Emergency Operations Manual

NPCC-New York Resource Adequacy Data

Demand, Resource, and Reserve Margin	2018 SRA	2019 SRA	2018 vs. 2019 SRA
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	32,904	32,382	-1.6%
Demand Response: Available	1,219	1,309	7.4%
Net Internal Demand	31,685	31,073	-1.9%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	39,066	37,304	-4.5%
Tier 1 Planned Capacity	260	27	-89.6%
Net Firm Capacity Transfers	1,625	1,452	-10.7%
Anticipated Resources	40,950	38,783	-5.3%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	40,950	38,783	-5.3%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	29.2%	24.8%	-4.4
Prospective Reserve Margin	29.2%	24.8%	-4.4
Reference Margin Level	18.2%	15.0%	-3.2

Highlights

- NYISO is not anticipating any operational issues in the New York control area for the upcoming summer operating period. Adequate capacity margins are anticipated and existing operating procedures are sufficient to handle any issues that may occur.
- High capacity factors on certain New York City peaking units could result in possible violations of their daily NOx emission limits if they were to fully respond to the NYISO dispatch signals. Significant run-time on peaking units, indicating the potential for a violation, could be the result of long duration hot weather events or loss of significant generation or transmission assets in New York City.

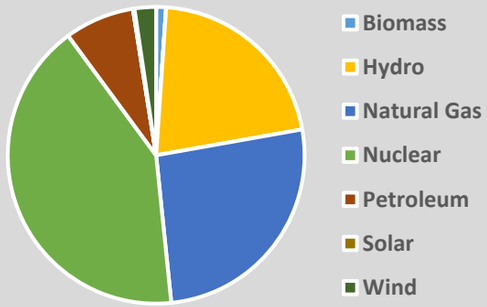


NPCC-Ontario

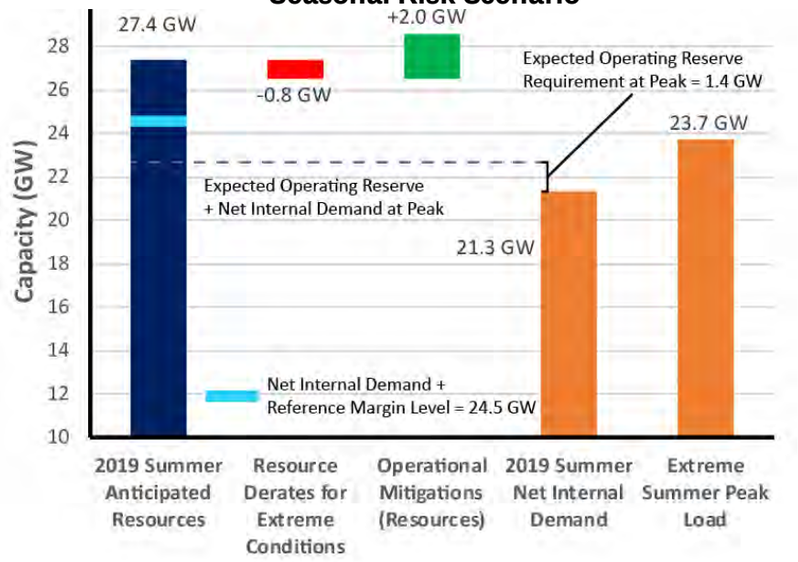
The Independent Electricity System Operator (IESO) is the Balancing Authority and Reliability Coordinator for the province of Ontario. In addition to administering the area's wholesale electricity markets, the IESO plans for Ontario's future energy needs. Ontario covers more than 415,000 square miles and has a population of more than 14 million people. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

Ontario IESO treats demand response as a resource for its own assessments, while in the NERC assessment demand response is used as a load-modifier. As a result, the total internal demand, reserve margin, and Reference Margin Level values differ in IESO's reports when compared to NERC reports.

On-Peak Capacity: Generation Mix



Seasonal Risk Scenario



NPCC-Ontario Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2018 SRA**	**2019 SRA**	**2018 vs. 2019 SRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	22,002	22,105	0.5%
Demand Response: Available	630	790	25.4%
Net Internal Demand	21,372	21,315	-0.3%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	25,731	26,581	3.3%
Tier 1 Planned Capacity	23	924	>100%
Net Firm Capacity Transfers	0	-102	-
Anticipated Resources	25,754	27,403	6.4%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	25,754	27,403	6.4%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	20.5%	28.6%	8.1
Prospective Reserve Margin	20.5%	28.6%	8.1
Reference Margin Level	13.3%	14.9%	1.6

The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels, with adjustments for normal and extreme conditions. NPCC-Ontario determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized below. See the **Seasonal Risk Scenario Chart Description** for more information about this chart.

Risk Scenario Summary

Observation:
Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** Based on severe historic weather conditions
- **Extreme Derates:** Based on thermal unit derating curves, and historical hydro performance in low-water year
- **Operational Mitigation:** 2,000 MW imports assessed as available from neighbors

Highlights

- There are sufficient resources to maintain the reliability of Ontario's electricity system under normal weather conditions for Summer 2019.
- The IESO recently revised its outage approval methods and will evaluate outages using its extreme weather scenario with only firm resources and up to 2,000 MW of imports.
- Driven by the need to enhance planning transparency and help market participants make more informed decisions and investments, the IESO has renewed its approach to planning with a particular emphasis on its commitment to regular sharing of information with stakeholders. As a first step in delivering on this commitment, and helping generators and transmitters plan for and schedule outages, the IESO now extends its 18-month outage planning horizon to five years twice yearly.

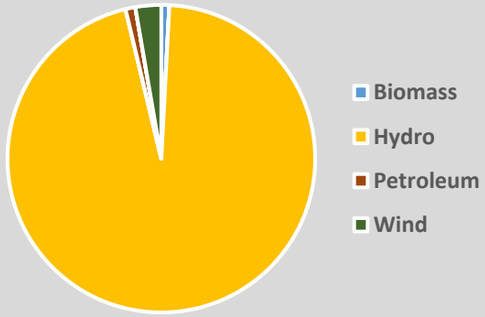


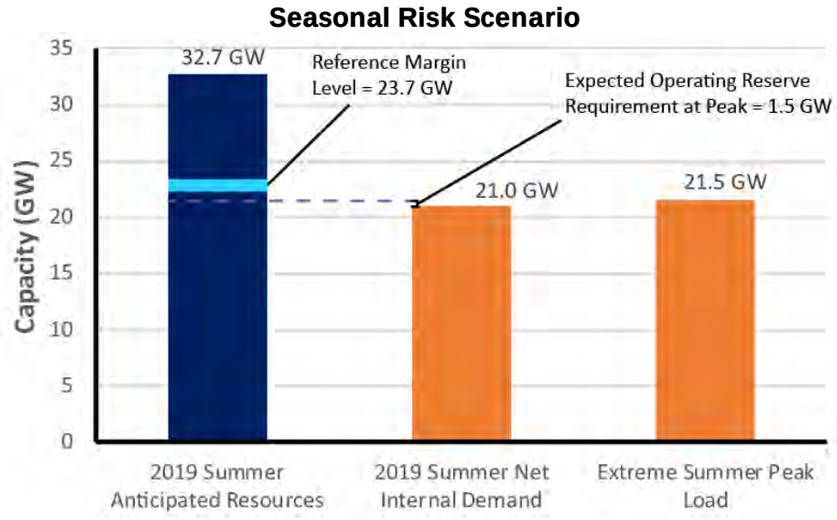
NPCC-Québec

The Québec Assessment Area (Province of Québec) is a winter-peaking NPCC subregion that covers 595,391 square miles with a population of eight million.

Québec is one of the four NERC Interconnections in North America, with ties to Ontario, New York, New England, and the Maritimes, consisting of either HVDC ties, radial generation, or load to and from neighboring systems.

On-Peak Capacity: Generation Mix





NPCC- Québec Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2018 SRA**	**2019 SRA**	**2018 vs. 2019 SRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	20,534	21,005	2.3%
Demand Response: Available	0	0	0.0%
Net Internal Demand	20,534	21,005	2.3%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	34,014	34,303	0.8%
Tier 1 Planned Capacity	0	28	-
Net Firm Capacity Transfers	-1,829	-1,663	-9.1%
Anticipated Resources	32,185	32,667	1.5%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	32,185	32,667	1.5%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	56.7%	55.5%	-1.2
Prospective Reserve Margin	56.7%	55.5%	-1.2
Reference Margin Level	12.6%	12.8%	0.2

The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels, with adjustments for normal and extreme conditions. NPCC-Québec determined the adjustments to peak demand based on methods or assumptions that are summarized below. See the **Seasonal Risk Scenario Chart Description** for more information about this chart.

Risk Scenario Summary

Observation:
Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** 90/10 forecast
- **Anticipated Resources:** Includes planned generator outages, deratings, bottling, historic hydroelectric reduction and 100% reduction in installed wind generation capacity

Highlights

- No issues are anticipated for the summer operating period since the system is winter peaking.
- A new 735 kV line is expected to be commissioned in May 2019 to meet NERC Reliability Standards and will provide more flexibility to operators.
- The Québec area expects to be able to provide assistance to neighboring areas if needed, up to the transfer capability available.

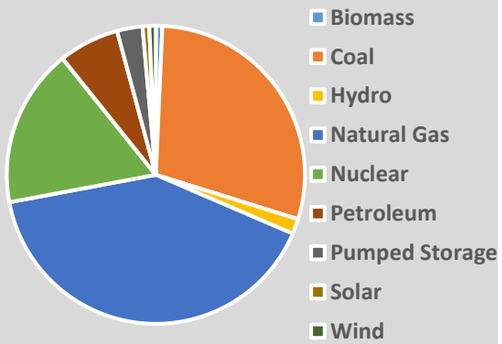


PJM

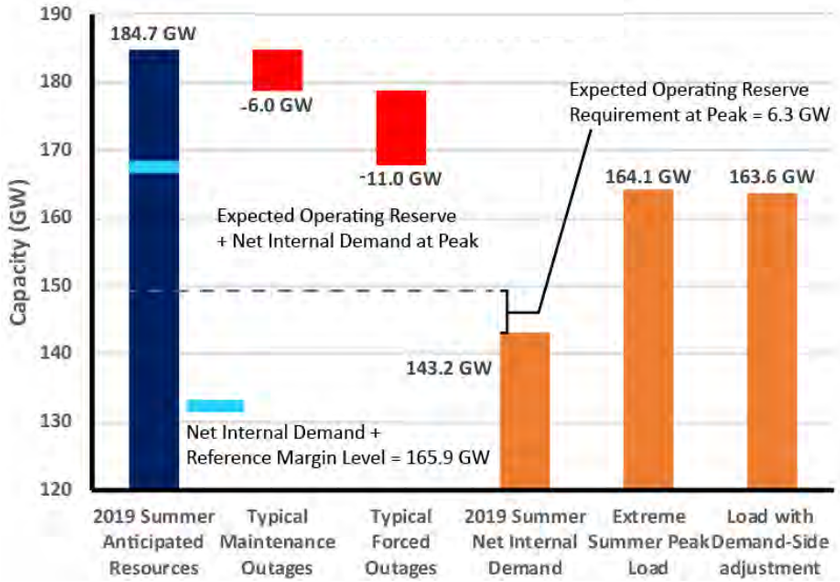
PJM Interconnection is a Regional Transmission Organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia.

PJM serves 65 million people and covers 369,089 square miles. PJM is a Balancing Authority, Planning Coordinator, Transmission Planner, Resource Planner, Interchange Authority, Transmission Operator, Transmission Service Provider, and Reliability Coordinator.

On-Peak Capacity: Generation Mix



Seasonal Risk Scenario



The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels, with adjustments for normal and extreme conditions. PJM determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized below. See the **Seasonal Risk Scenario Chart Description** for more information about this chart.

Risk Scenario Summary

Observation:
Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** 90/10 Forecast
- **Outages:** Approximate values based on review of previous summer peak periods

PJM Resource Adequacy Data

Demand, Resource, and Reserve Margin	2018 SRA	2019 SRA	2018 vs. 2019 SRA
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	152,108	151,358	-0.5%
Demand Response: Available	9,095	8,154	-10.3%
Net Internal Demand	143,013	143,204	0.1%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	185,440	181,013	-2.4%
Tier 1 Planned Capacity	0	2,200	-
Net Firm Capacity Transfers	4,419	1,535	-65.3%
Anticipated Resources	189,859	184,748	-2.7%
Existing-Other Capacity	0	0	0
Prospective Resources	189,859	184,748	-2.7%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	32.8%	29.0%	-3.8
Prospective Reserve Margin	32.8%	29.0%	-3.8
Reference Margin Level	16.1%	15.9%	-0.2

Highlights

- The PJM reserve margin for this summer is 29.0% with a requirement of 15.9%. With this level of capacity, PJM has not identified any emerging reliability issues regarding resource adequacy.
- Ohio Valley Electric Cooperative (OVEC) moved from MISO into PJM in December 2018. OVEC has two large generating plants that have moved from having significant transfers into PJM to now being part of the PJM market dispatch.



SERC

SERC's assessment areas are traditionally summer-peaking and cover approximately 72,000 circuit miles and serve a population estimated at 23 million.

For NERC's assessment, the Region is divided into three assessment areas: SERC- E, SERC-C, and SERC-SE. The assessment areas include 12 Balancing Authorities: Cube Hydro Carolinas LLC, Associated Electric Cooperative, Inc. (AECI), Duke Energy Carolinas (DEC), Duke Energy Progress (DEP), Electric Energy, Inc. (EEI), LG&E and KU Services Company (as agent for Louisville Gas and Electric and Kentucky Utilities (LG&E/ KU)), PowerSouth Energy Cooperative (PowerSouth), South Carolina Electric & Gas Company (SCE&G), South Carolina Public Service Authority (SCPSA), Southern Company Services, Inc. (SOCO), Southeastern Power Administration (SPA), and Tennessee Valley Authority (TVA).

SERC Resource Adequacy Data						
Demand, Resource, and Reserve Margins	**SERC-E**	**SERC-C**	**SERC-SE**	**2018 SRA SERC Total**	**2019 SRA SERC Total**	**2018 vs. 2019 SRA**
Demand Projections	**Megawatts**	**Megawatts**	**Megawatts**	**Megawatts**	**Megawatts**	**Net Change (%)**
Total Internal Demand (50/50)	43,704	40,781	47,311	131,994	131,796	-0.2%
Demand Response: Available	1,054	1,964	2,293	4,640	5,311	14.5%
Net Internal Demand	42,650	38,817	45,018	127,354	126,485	-0.7%
Resource Projections	**Megawatts**	**Megawatts**	**Megawatts**	**Megawatts**	**Megawatts**	**Net Change (%)**
Existing-Certain Capacity	50,976	50,391	61,182	161,532	162,549	0.6%
Tier 1 Planned Capacity	0	0	458	1,875	458	-75.6%
Net Firm Capacity Transfers	455	301	-1,905	-3,133	-1,150	-63.3%
Anticipated Resources	51,431	50,692	59,734	160,274	161,857	1.0%
Existing-Other Capacity	852	4,060	289	2,361	5,200	120.2%
Prospective Resources	52,282	54,752	60,023	162,635	167,057	2.7%
Planning Reserve Margins	**Percent**	**Percent**	**Percent**	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	20.6%	30.6%	32.7%	25.9%	28.0%	2.1
Prospective Reserve Margin	22.6%	41.1%	33.3%	27.7%	32.1%	4.4
Reference Margin Level	13.15%	13.15%	13.15%	15.00%	13.15%	-1.85

Highlights

- To date, there are no significant reliability risks expected for the 2019 summer season in the SERC Region.
- SERC continues to prepare for the integration of entities within FRCC. Both FRCC and the SERC Region are coordinating activities to ensure a successful transition of the new registered entities into the SERC Region's reliability programs and processes. For more information, visit the FRCC RE Integration webpage.[9]
- To align with SERC's subregional naming convention in its regional studies and assessments, the SERC North Assessment Area was changed to SERC Central Assessment Area in NERC Reliability Assessments.
- SERC Southeast entities have experienced loop flows from a high regional transfers between MISO North and MISO South. As a result, the impacted utilities along with MISO developed an operating procedure to address potential reliability issues that could result from high MISO regional transfers.

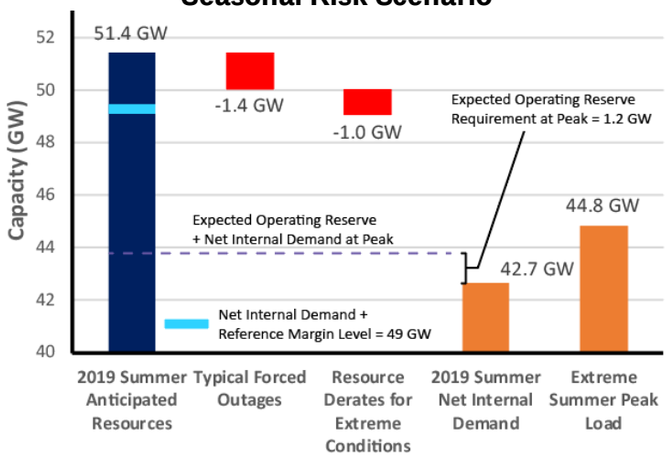
Charts

The charts on the next page provide potential summer peak demand and resource condition information. The table above presents a standard seasonal assessment and comparison to the previous year's assessment. The waterfall charts on the next page present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. SERC determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized on the next page. See the **Seasonal Risk Scenario Chart Description** for more information about the charts.

[9] See http://www.serc1.org/outreach/frcc-re-integration

SERC-E

Seasonal Risk Scenario



Risk Scenario Summary

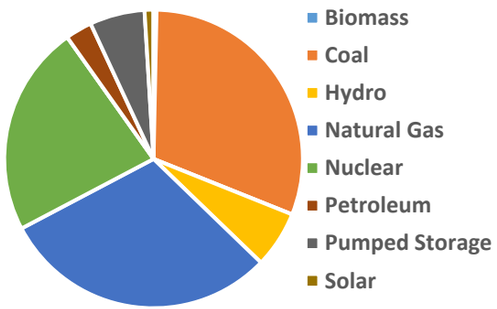
Observation:

Resources meet operating reserve requirements under studied scenarios

Scenario Assumptions

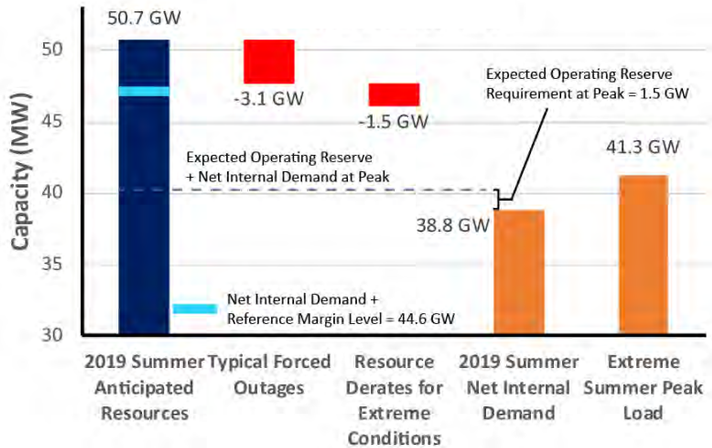
- **Extreme Peak Load:** Based on 2018 SERC Probabilistic Assessment, equal to or exceeding a 90/10 statistical level
- **Outages:** Based on historical data
- **Extreme Derates:** Based on 2018 SERC Probabilistic Assessment, equal to or exceeding a 90/10 statistic

On-Peak Capacity: Generation Mix



SERC-C

Seasonal Risk Scenario



Risk Scenario Summary

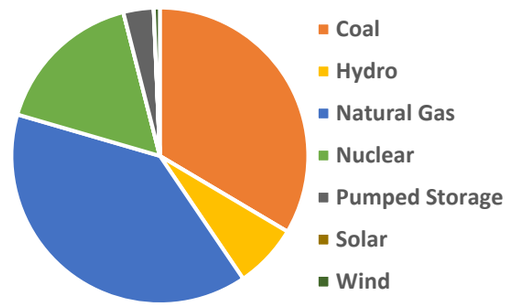
Observation:

Resources meet operating reserve requirements under studied scenarios

Scenario Assumptions

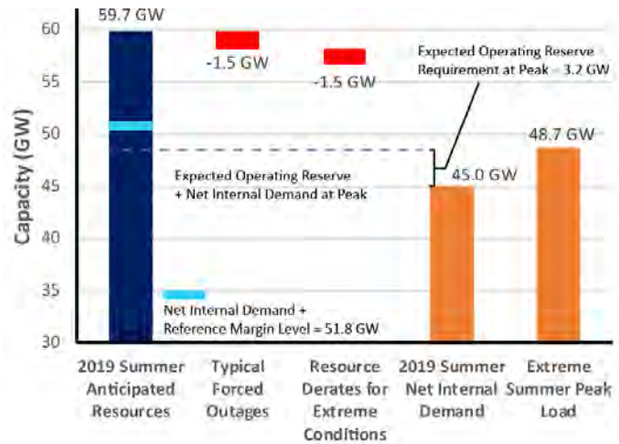
- **Extreme Peak Load:** Based on 2018 SERC Probabilistic Assessment, equal to or exceeding a 90/10 statistical level
- **Outages:** Based on historical data
- **Extreme Derates:** Based on 2018 SERC Probabilistic Assessment, equal to or exceeding a 90/10 statistic

On-Peak Capacity: Generation Mix



SERC-SE

Seasonal Risk Scenario



Risk Scenario Summary

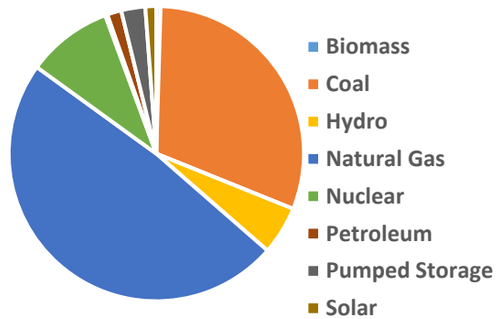
Observation:

Resources meet operating reserve requirements under studied scenarios

Scenario Assumptions

- **Extreme Peak Load:** Based on 2018 SERC Probabilistic Assessment, equal to or exceeding a 90/10 statistical level
- **Outages:** Based on historical data
- **Extreme Derates:** Based on 2018 SERC Probabilistic Assessment, equal to or exceeding a 90/10 statistic

On-Peak Capacity: Generation Mix



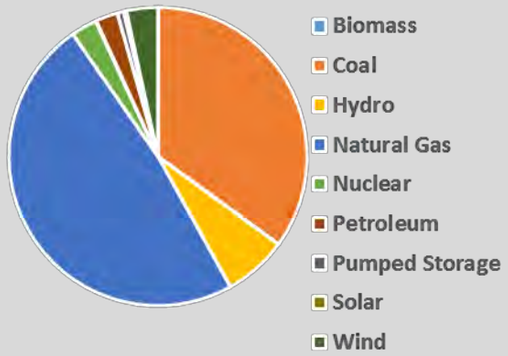


SPP

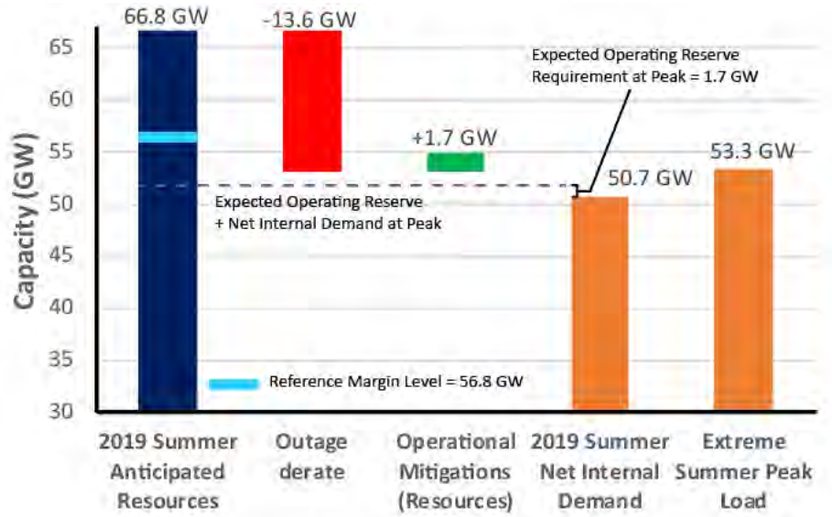
Southwest Power Pool (SPP) Planning Coordinator footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas and Wyoming.

The SPP long-term assessment is reported based on the Planning Coordinator footprint, which touches parts of the Midwest Reliability Organization Regional Entity, and WECC. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million people.

On-Peak Capacity: Generation Mix



Seasonal Risk Scenario



The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels, with adjustments for normal and extreme conditions. SPP determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized below. See the **Seasonal Risk Scenario Chart Description** for more information about this chart.

Risk Scenario Summary

Observation: Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** 90/10 Forecast
- **Outages:** A derate for forced outages and performance in extreme weather based on historical data

SPP Resource Adequacy Data

Demand, Resource, and Reserve Margin	2018 SRA	2019 SRA	2018 vs. 2019 SRA
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	52,554	51,520	-2.0%*
Demand Response: Available	867	835	-3.8%
Net Internal Demand	51,687	50,685	-1.9%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	67,649	67,960	0.5%
Tier 1 Planned Capacity	779.85	64	-91.8%
Net Firm Capacity Transfers	19	-1,244	-
Anticipated Resources	68,447	66,780	-2.4%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	68,447	66,780	-2.4%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	32.4%	31.8%	-0.6
Prospective Reserve Margin	32.4%	31.8%	-0.6
Reference Margin Level	12.0%	12.0%	0.0

* In 2018, Total Internal Demand was calculated on a non-coincident peak basis, resulting in higher demand calculations compared to coincident peak basis used for the 2019 SRA.

Highlights

- SPP does not anticipate any emerging reliability issues impacting the area for the 2019 summer season.
- SPP has experienced mid-range forecast error uncertainty in wind forecasts as the penetration of wind generation increases. This is not an issue if the error is short lived, but if the error continues throughout the day it can lead to short-term supply scarcity. Within SPP, a team is developing mitigation to ensure appropriate ramp product is available on a daily basis.

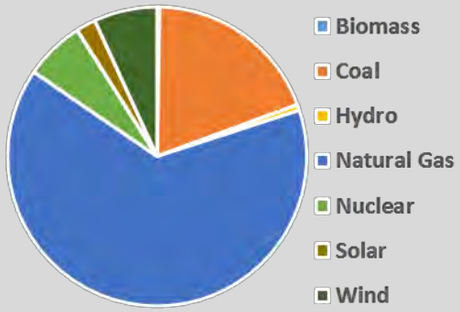


Texas RE-ERCOT

The Electric Reliability Council of Texas (ERCOT) is the ISO for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single Balancing Authority. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature.

ERCOT is a summer-peaking Region that covers approximately 200,000 square miles, connects over 46,500 miles of transmission lines, has 650 generation units, and serves more than 25 million customers. Texas RE is responsible for the regional RE functions described in the Energy Policy Act of 2005 for the ERCOT Region.

On-Peak Capacity: Generation Mix



Texas RE-ERCOT Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2018 SRA**	**2019 SRA**	**2018 vs. 2019 SRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	72,756	74,853	2.9%
Demand Response: Available	2,301	2,227	-3.2%
Net Internal Demand	70,455	72,626	3.1%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	76,654	77,482	1.1%
Tier 1 Planned Capacity	738.95	607	-17.9%
Net Firm Capacity Transfers	753	721	-4.2%
Anticipated Resources	78,146	78,810	0.9%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	78,146	78,810	0.9%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	10.9%	8.5%	-2.4
Prospective Reserve Margin	10.9%	8.5%	-2.4
Reference Margin Level	13.75%	13.75%	0.0

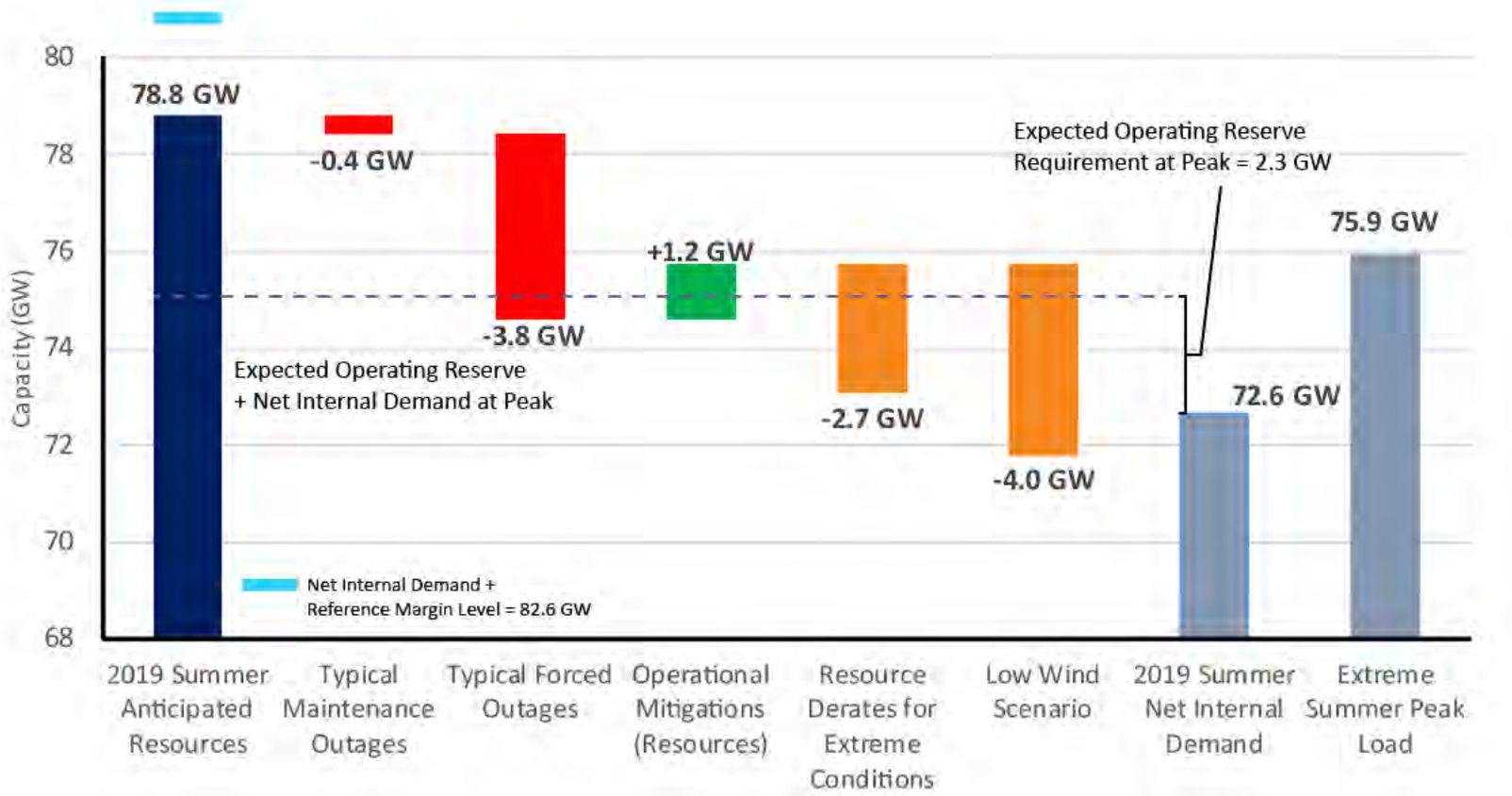
Highlights

- Despite growth in anticipated resources relative to last summer, even higher expected summer peak demand, combined with delays in planned generation projects and the announced mothballing of a 470 MW coal-fired unit, are expected to result in a tighter reserve margin for the upcoming summer.
- Notable transmission improvements include a new 250 MVAr STATCOM expected to be in-service prior to summer in the Far West Texas region to support the rapid growth of oil and gas production load in the Permian Basin. Additionally, a new 345 kV line in Central Texas will be energized in the spring to support the San Antonio area.
- There are no known transmission reliability, fuel supply, or essential reliability service procurement issues projected for the upcoming season. However, delays or cancellations of planned transmission expansion projects, if they occur, may contribute to potential localized reliability concerns.

Charts

The chart on the next page provide potential summer peak demand and resource condition information. The table above presents a standard seasonal assessment and comparison to the previous year's assessment. The waterfall charts on the next page present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. ERCOT determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized on the next page. See the **Seasonal Risk Scenario Chart Description** for more information about the chart.

Seasonal Risk Scenario



The table on page 26 and the chart above provide potential summer peak demand and resource condition information. The table presents a standard seasonal assessment and comparison to the previous year's assessment. The chart presents deterministic scenarios for further analysis of different demand and resource levels, with adjustments for normal and extreme conditions.

Risk Scenario Summary

Observation:

Operating Mitigations and Energy Emergency Alerts may be needed under peak and extreme conditions studied.

Scenario Assumptions (see Table 1 on Page 9 for detailed discussion)

- **Extreme Peak Load:** Based on 2011 historic summer peak load
- **Outages:** A derate for maintenance and forced outages based on the past three year summer periods
- **Operational Mitigations.** Additional resources (e.g., switchable generation resources, additional imports, and voltage reduction) to support maintaining operating reserves, not already counted in SRA reserve margins.



WECC

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members, which include 38 Balancing Authorities, represent a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million people, it is geographically the largest and most diverse of the NERC Regional Entities. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 western states in between. The WECC assessment area is divided into six subregions: Rocky Mountain Reserve Group (RMRG), Southwest Reserve Sharing Group (SRSG), California/Mexico (CA/MX), the Northwest Power Pool (NWPP), and the Canadian areas of Alberta (WECC AB) and British Columbia (WECC BC). These subregional divisions are used for this study, as they are structured around reserve sharing groups that have similar annual demand patterns and similar operating practices.

WECC Resource Adequacy Data									
Demand, Resource, and Reserve Margins	**WECC AB**	**WECC BC**	**CA/MX**	**NWPP-US**	**RMRG**	**SRSG**	**2018**	**2019**	**2018 vs. 2019 SRA**
Demand Projections	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**Total MW**	**Total MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,111	8,432	52,929	47,619	12,636	23,415	154,256	156,142	1.2%
Demand Response: Available	0	0	957	614	225	368	3,569	2,164	-39.4%
Net Internal Demand	11,111	8,432	51,972	47,006	12,411	23,047	150,687	153,979	2.2%
Resource Projections	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	14,560	9,746	61,806	60,056	16,627	31,413	184,981	194,208	5.0%
Tier 1 Planned Capacity	43	152	1,818	1,007	257	684	1,098	3,961	>100%
Net Firm Capacity Transfers	0	0	0	0	0	0	0	0	0.0%
Anticipated Resources	14,603	9,898	63,624	61,063	16,884	32,097	186,079	198,169	6.5%
Existing-Other Capacity	0	0	0	0	0	0	0	0	0.0%
Prospective Resources	14,603	9,898	63,624	61,063	16,884	32,097	186,079	198,169	6.5%
Planning Reserve Margins	**Percent**	**Percent**	**Percent**	**Percent**	**Percent**	**Percent**	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	31.4%	17.4%	22.4%	29.9%	36.0%	39.3%	23.5%	28.7%	5.2
Prospective Reserve Margin	31.4%	17.4%	22.4%	29.9%	36.0%	39.3%	23.5%	28.7%	5.2
Reference Margin Level	10.0%	10.0%	12.0%	20.0%	17.0%	15.0%	15.4%	15.4%	0.0

Highlights

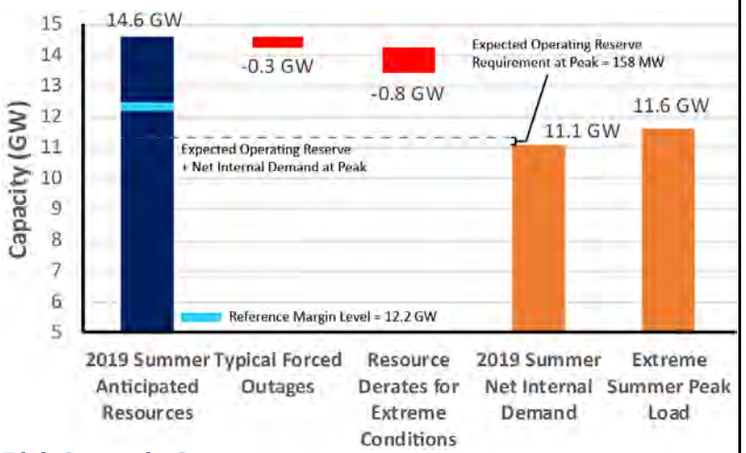
- The existing and Anticipated Reserve Margins for WECC, its subregions, and all zones within are expected to exceed their respective NERC Reference Margin Levels for the upcoming season.
- WECC and NERC are monitoring the transition of Reliability Coordinator (RC) responsibilities in the Western Interconnection as Peak RC winds down toward disestablishment at the end of 2019. NERC-certified RCs are scheduled to assume responsibilities in California (July 1) and British Columbia (September 2). All other areas will complete transition prior to December 31. Certification site visits, shadow-operating periods with Peak RC, and WECC-sponsored RC transition activities are being implemented to manage reliability risks.
- Inventories of the Aliso Canyon natural gas storage facility remain an item of focus for reliability within the Western Interconnection. This condition is being closely monitored by the CAISO, SoCal Gas, and WECC's Situational Awareness group.
- Above-average snowpack levels and the anticipated abundance of hydroelectric generation in California may be used to displace generation from natural-gas-fired units, freeing up more natural gas for Southern California if fuel availability becomes an issue.
- Localized short-term operational issues may occur due to wildfires, if seasonal wildfire predictions are accurate. Due to the widely dispersed nature of the transmission system, outages due to wildfires are generally not widespread.

Charts

The charts on the next page provide potential summer peak demand and resource condition information. The table above presents a standard seasonal assessment and comparison to the previous year's assessment. The waterfall charts on the next page present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. WECC entities determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized on the next page. See the **Seasonal Risk Scenario Chart Description** for more information about the charts.

WECC-Alberta

Seasonal Risk Scenario



Risk Scenario Summary

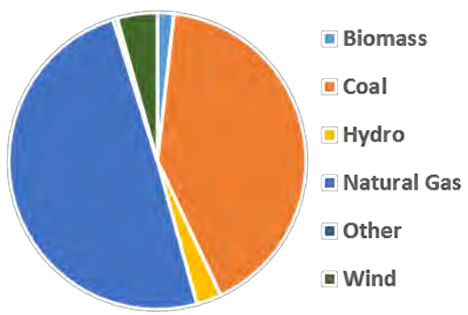
Observation:

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

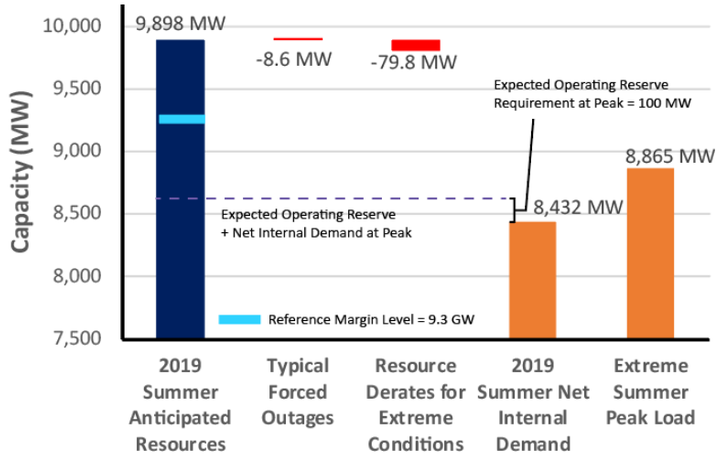
- **Extreme Peak Load:** Based on 90/10 demand forecast
- **Forced Outages:** Based on historical data
- **Extreme Derates:** Derates for thermal, wind, and solar were developed using the tenth percentile availability curves for the respective resources for the assessment area peak hour

On-Peak Capacity: Generation Mix



WECC-British Columbia

Seasonal Risk Scenario



Risk Scenario Summary

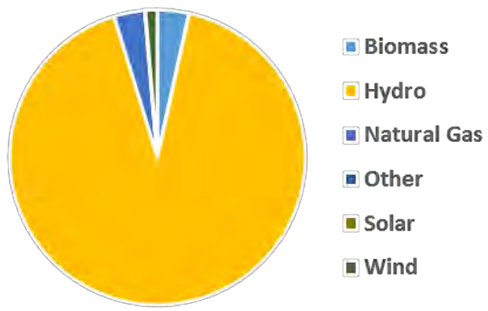
Observation:

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

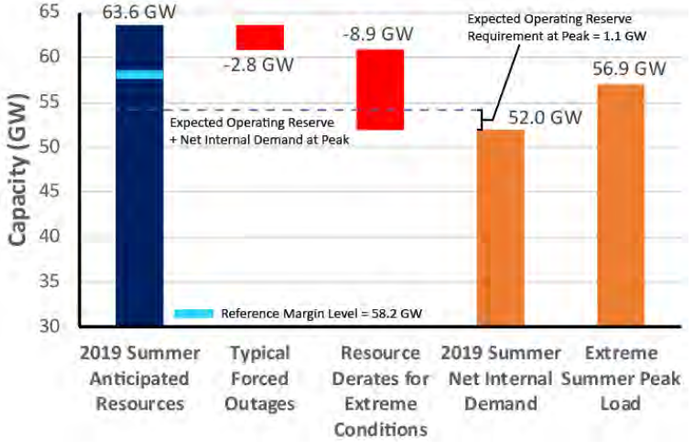
- **Extreme Peak Load:** Based on 90/10 demand forecast
- **Forced Outages:** Based on historical data
- **Extreme Derates:** Derates for thermal, wind, and solar were developed using the tenth percentile availability curves for the respective resources for the assessment area peak hour

On-Peak Capacity: Generation Mix



WECC-California / Mexico

Seasonal Risk Scenario



Risk Scenario Summary

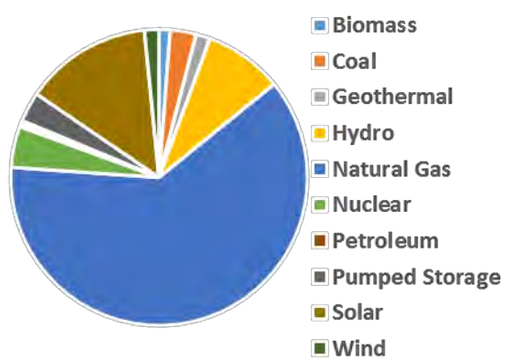
Observation:

Resources meet operating reserve requirements for typical outage conditions, peak load, and extreme peak loads. Extreme outages may result in insufficient resources at peak load.

Scenario Assumptions

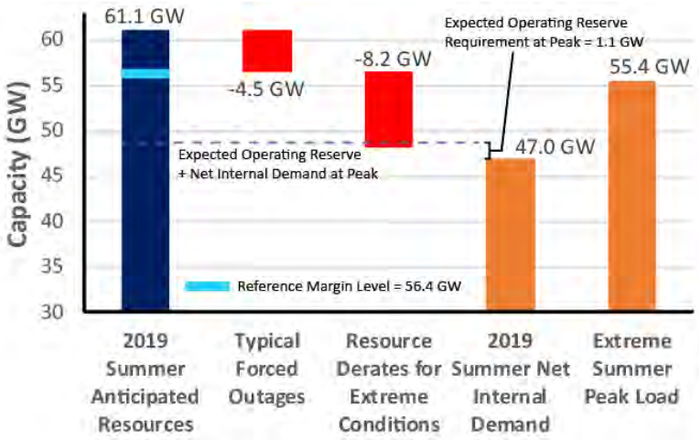
- **Extreme Peak Load:** Based on 90/10 demand forecast
- **Forced Outages:** Based on historical data
- **Extreme Derates:** Derates for thermal, wind, and solar were developed using the tenth percentile availability curves for the respective resources for the assessment area peak hour

On-Peak Capacity: Generation Mix



WECC-Northwest Power Pool

Seasonal Risk Scenario



Risk Scenario Summary

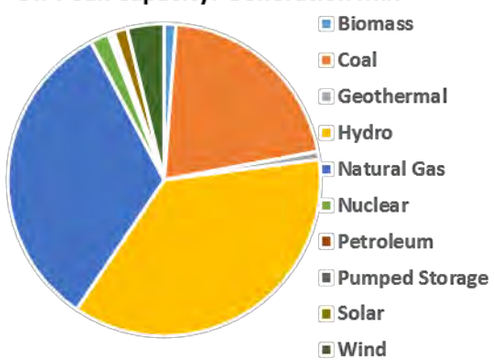
Observation:

Resources meet operating reserve requirements for typical outage conditions, peak load, and extreme peak loads. Extreme outages may result in insufficient resources at peak load.

Scenario Assumptions

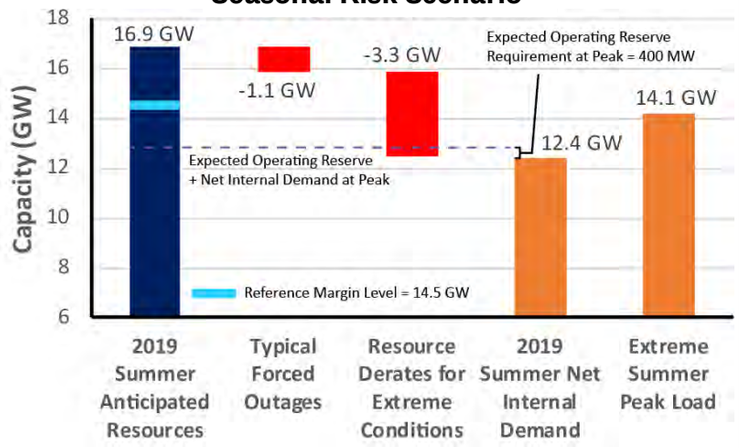
- **Extreme Peak Load:** Based on 90/10 demand forecast
- **Forced Outages:** Based on historical data
- **Extreme Derates:** Derates for thermal, wind, and solar were developed using the tenth percentile availability curves for the respective resources for the assessment area peak hour

On-Peak Capacity: Generation Mix



WECC-Rocky Mountain Reserve Sharing Group

Seasonal Risk Scenario



Risk Scenario Summary

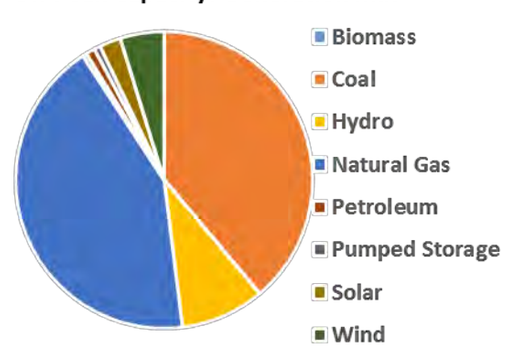
Observation:

Resources meet operating reserve requirements for typical outage conditions, peak load, and extreme peak loads. Extreme outages may result in insufficient resources at peak load.

Scenario Assumptions

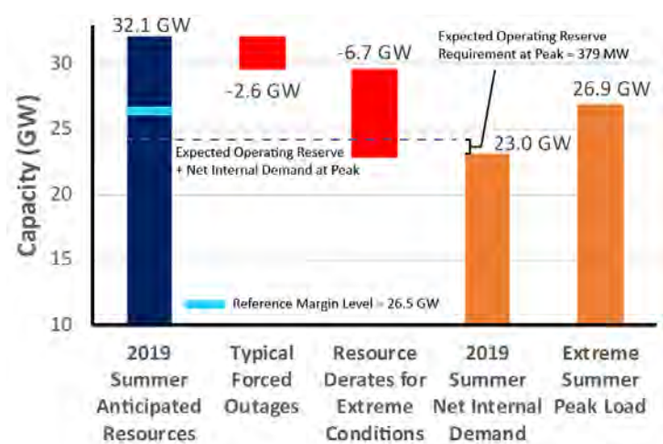
- **Extreme Peak Load:** Based on 90/10 demand forecast
- **Forced Outages:** Based on historical data
- **Extreme Derates:** Derates for thermal, wind, and solar were developed using the tenth percentile availability curves for the respective resources for the assessment area peak hour

On-Peak Capacity: Generation Mix



WECC-Southwest Reserve Sharing Group

Seasonal Risk Scenario



Risk Scenario Summary

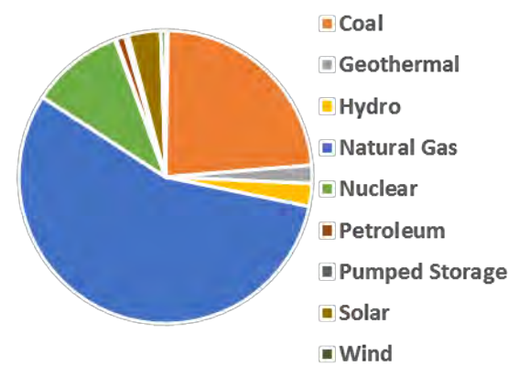
Observation:

Resources meet operating reserve requirements for typical outage conditions, peak load, and extreme peak loads. Extreme outages may result in insufficient resources at peak load.

Scenario Assumptions

- **Extreme Peak Load:** Based on 90/10 demand forecast
- **Forced Outages:** Based on historical data
- **Extreme Derates:** Derates for thermal, wind, and solar were developed using the tenth percentile availability curves for the respective resources for the assessment area peak hour

On-Peak Capacity: Generation Mix



Data Concepts and Assumptions

The table below explains data concepts and important assumptions used throughout this assessment.

General Assumptions

- Reliability of the interconnected BPS is comprised of both adequacy and operating reliability.
  - Adequacy is the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
  - Operating reliability is the ability of the electric system to withstand sudden disturbances such as electric short-circuits or unanticipated loss of system components.
- The reserve margin calculation is an important industry planning metric used to examine future resource adequacy.
- All data in this assessment is based on existing federal, state, and provincial laws and regulations.
- Differences in data collection periods for each assessment area should be considered when comparing demand and capacity data between year-to-year seasonal assessments.
- *2018 Long-Term Reliability Assessment* data has been used for most of this 2019 assessment period, augmented by updated load and capacity data.
- A positive net transfer capability would indicate a net importing assessment area; a negative value would indicate a net exporter.

Demand Assumptions

- Electricity demand projections, or load forecasts, are provided by each assessment area.
- Load forecasts include peak hourly load[10], or total internal demand, for the summer and winter of each year.[11]
- Total internal demand projections are based on normal weather (50/50 distribution[12]) and are provided on a coincident[13] basis for most assessment areas.
- Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour.

Resource Assumptions

Resource planning methods vary throughout the North American BPS. NERC uses the following categories to provide a consistent approach for collecting and presenting resource adequacy:

Anticipated Resources:

- **Existing-Certain Capacity**: included in this category are commercially operable generating units, or portions of generating units, that meet at least one of the following requirements when examining the period of peak demand for the summer season: unit must have a firm capability and have a power purchase agreement (PPA) with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or where energy-only markets exist, unit must be a designated market resource eligible to bid into the market.
- **Tier 1 Capacity Additions**: includes capacity that either is under construction or has received approved planning requirements.
- **Net Firm Capacity Transfers (Imports minus Exports)**: transfers with firm contracts.

Prospective Resources: Includes all anticipated resources, plus the following:

Existing-Other Capacity: included in this category are commercially operable generating units, or portions of generating units, that could be available to serve load for the period of peak demand for the summer or summer season but do not meet the requirements of existing-certain.

Reserve Margin Definitions

Reserve Margins: the primary metric used to measure resource adequacy; it is defined as the difference in resources (anticipated or prospective) and net internal demand then divided by net internal demand, shown as a percentage:

[10] *Glossary of Terms* Used in NERC Reliability Standards

[11] The summer season represents June–September and the winter season represents December–February.

[12] Essentially, this means that there is a 50% probability that actual demand will be higher and a 50% probability that actual demand will be lower than the value provided for a given season/year.

[13] Coincident: The sum of two or more peak loads that occur in the same hour. Noncoincident: The sum of two or more peak loads on individual systems that do not occur in the same time interval. Meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year. SERC and FRCC calculate total internal demand on a noncoincidental basis

Seasonal Risk Scenario Chart Description

Each assessment area performed an operational risk analysis that was used to produce the seasonal risk scenario charts in the **Regional Assessment Dashboards**. The chart presents deterministic scenarios for further analysis of different resource and demand levels. The left blue column shows Summer Anticipated Resources (from the Resource Adequacy Data table). The two orange columns at the right show two demand scenarios: normal peak net internal demand from the Resource Adequacy Data table and an extreme summer peak demand, both determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the Summer Anticipated Resources, such as the following:

- Reductions for typical generation outages (maintenance and forced, not already accounted for in Summer Anticipated Resources)
- Reductions that represent additional outage or performance derating by resource type for extreme, low-probability conditions (e.g., drought condition impacts on hydroelectric generation, low-wind scenario affecting wind generation, fuel supply limitations, or extreme temperature conditions resulting in reduced thermal generation output)
- Additional capacity resources that represent quantified capacity from operational procedures, if any, that are made available during scarcity conditions

Not all assessment areas have the same categories of adjustments to anticipated resources. Furthermore, each assessment area determined the adjustments to summer capacity based on methods or assumptions that are summarized below the chart. Methods and assumptions differ by assessment area and may not be comparable.

The chart enables evaluation of resource levels against levels of expected operating reserve requirement and the forecasted demand. Further, the effects from low-probability, extreme events can also be examined by comparing resource levels after applying extreme-scenario derates and/or extreme summer peak demand. Because such extreme scenario analysis depicts the cumulative impact resulting from the occurrence of multiple low-probability events, the overall likelihood of the scenario is very low.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2020 Summer Reliability Assessment

June 2020



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Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is divided into six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Region while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

About this Report

NERC's *2020 Summer Reliability Assessment* (SRA) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming summer season. In addition, the SRA presents peak electricity demand and supply changes and highlights any unique regional challenges or expected conditions that might impact the BPS. The reliability assessment process is a coordinated reliability evaluation between the Reliability Assessment Subcommittee (RAS), the Regions, and NERC staff. This report reflects NERC's independent assessment and is intended to inform industry leaders, planners, operators, and regulatory bodies so they are better prepared to take necessary actions to ensure BPS reliability. This report also provides an opportunity for the industry to discuss plans and preparations to ensure reliability for the upcoming summer period.

In April 2020, NERC published its *Special Report Pandemic Preparedness and Operational Assessment: Spring 2020* to advise electricity stakeholders about elevated risk to electric reliability as a result of the global health crisis.[1] NERC continues to assess risks to the reliability and security of the BPS from the global health crisis and reports on industry actions and preparedness in this SRA.

[1] https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC_Pandemic_Preparedness_and_Op_Assessment_Spring_2020.pdf

Findings

NERC's annual SRA covers the Summer 2020 (June–September) period. This assessment provides an evaluation of resource and transmission system adequacy necessary to meet projected summer peak demands. In addition to assessing resource adequacy, the SRA monitors and identifies potential reliability issues of interest and regional topics of concern. In 2020, there is heightened uncertainty in demand projections stemming from the progression of the coronavirus (COVID-19) pandemic and the response of governments, society, and the electricity industry. The following key findings represent NERC's independent evaluation of electric generation and transmission capacity as well as potential operational concerns that may need to be addressed for the upcoming summer:

- **Sufficient capacity resources are expected to be in-service for the upcoming summer.** In all areas, with the exception of ERCOT, the Anticipated Reserve Margin meets or surpasses the Reference Margin Level, indicating that planned resources in these areas are adequate to manage risk of a capacity deficiency under normal conditions.[2] Assessment areas are prepared to meet potential peak demand with or without pandemic-related demand reductions. Should pandemic related restrictions continue through the summer, peak demand is expected to be lower than forecast.
  - **Texas RE-ERCOT**. Projections for increased peak demand in ERCOT indicate the potential for energy emergency alerts (EEAs) during summer peak periods. Prior to the arrival of COVID-19 and the resulting mitigations that have impacted electricity demand, ERCOT planners were expecting similarly tight operating conditions to those faced in Summer 2019. The ERCOT Anticipated Reserve Margin has risen from 8.5% in Summer 2019 to 12.9% for the upcoming summer. The increase in reserve margin is driven by the addition of over 1.9 GW of on-peak resource capacity. ERCOT's forecast of peak demand for Summer 2020 is also forecasted to grow in 2020, but higher-growth projections have been tempered in recent months by COVID-19 economic impacts. The potential for EEAs and operating mitigation at peak load remains.
- **Maintenance and preparations for summer operations impacted by pandemic.** As summer peak operating season approaches each year, generator and transmission owners and operators engage in extensive preparations, including preventive maintenance, supply stocking, and training programs. However, many normal efforts have been impinged by the global pandemic. To avoid the risk of failing to complete maintenance on-time, some owners and operators have deferred or cancelled preseason maintenance in response to pandemic-related issues. Monitoring the progress of ongoing efforts to prepare staff and equipment for summer will be important to ensuring the availability of anticipated resources to meet electricity demand. Furthermore, system operators must be prepared to address demand forecast uncertainty and potentially challenging operating conditions as a result of low demand on the system.
- **Protecting critical electric industry workforce during the COVID-19 pandemic remains a priority for reliability and resilience.** System and generation plant operators have implemented operating postures and personnel restrictions prescribed by their pandemic plans in order to protect essential personnel and support reliable operations. Many of these measures will need to be maintained for the foreseeable future. There is a continuing risk that control centers or plants could be temporarily shut down if a significant number of operators or plant employees test positive for COVID-19 despite preparedness efforts. When relaxations can be implemented, operators will likely need to stay postured to return to heightened protections in response to dynamic public health conditions.
- **Late-summer wildfire season in western United States and Canada poses risk to BPS reliability.** Government agencies warn of the potential for above-normal wildfire risk beginning as early as June in parts of the Western United States as well as Central and Western Canada.[3] Operation of the BPS can be impacted in areas where wildfires are active as well as areas where there is heightened risk of wildfire ignition due to weather and ground conditions.

[2] For more information, see the description of the "Reference Margin Level" in the **Data Concepts and Assumptions** section of this report or refer to NERC's *Long-term Reliability Assessment*: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2019.pdf

[3] See North American Seasonal Fire Assessment and Outlook, April 2020: https://www.predictiveservices.nifc.gov/outlooks/NA_Outlook.pdf

Resource Adequacy

The Anticipated Reserve Margin, which is based on available resource capacity, is a metric used to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecasted peak demand.[4] Large year-to-year changes in anticipated resources or forecasted peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. Other than in ERCOT, all assessment areas have sufficient Anticipated Reserve Margins to meet or exceed their Reference Margin Level for Summer 2020 as shown in the **Figure 1**.

Although the pandemic introduces significant uncertainty into demand and some risk to generation resource availability, as discussed in the following section, the projections below provide indication that adequate resources are available to meet peak demand.

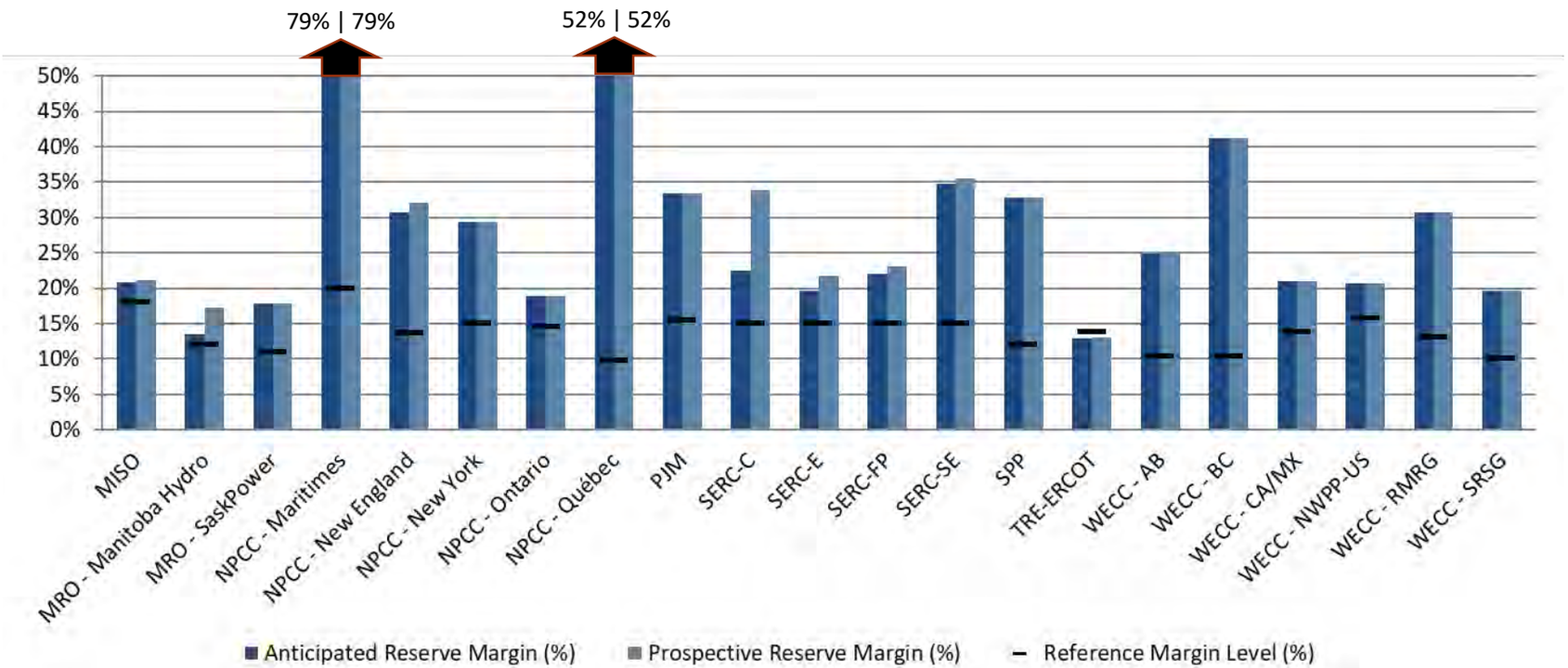


Figure 1: Summer 2020 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[4] Generally, anticipated resources include generators and firm capacity transfers that are expected to be available to serve load during electrical peak loads for the season. Prospective Resources are those that could be available but do not meet criteria to be counted as Anticipated Resources. Refer to the **Data Concepts and Assumptions** section for additional information on Anticipated/Prospective Reserve Margins, Anticipated/Prospective Resources, and Reference Margin Levels.

Changes from Year-to-Year

Understanding the changes from year-to-year is an essential step in assessing an area on a seasonal basis. **Figure 2** provides the relative change from the Summer 2019 to the Summer 2020 period. The **Regional Assessment Dashboards** provide details of the demand and resource components that make up the anticipated reserve margins for each assessment area. In the following areas, anticipated reserve margin changed by more than five percentage points: none of the changes result in a resource adequacy concern for the upcoming summer.

- **NPCC Maritimes:** The retirements of one coal-fired generator and two biomass generators contributed to lower anticipated reserve margins.
- **NPCC Ontario:** Anticipated Reserve Margins decrease due to nuclear unit refurbishments and reductions in the contribution of demand response and hydro.
- **WECC BC and WECC SRSG:** Reserve margin changes are attributed to revised variable generation capacity factors and changes in peak-hour demand.
- **WECC NWPP-US:** Forecasted summer peak demand increased by 6,300 MW (13.5%) while resource levels were relatively stable, resulting in lower reserve margins.

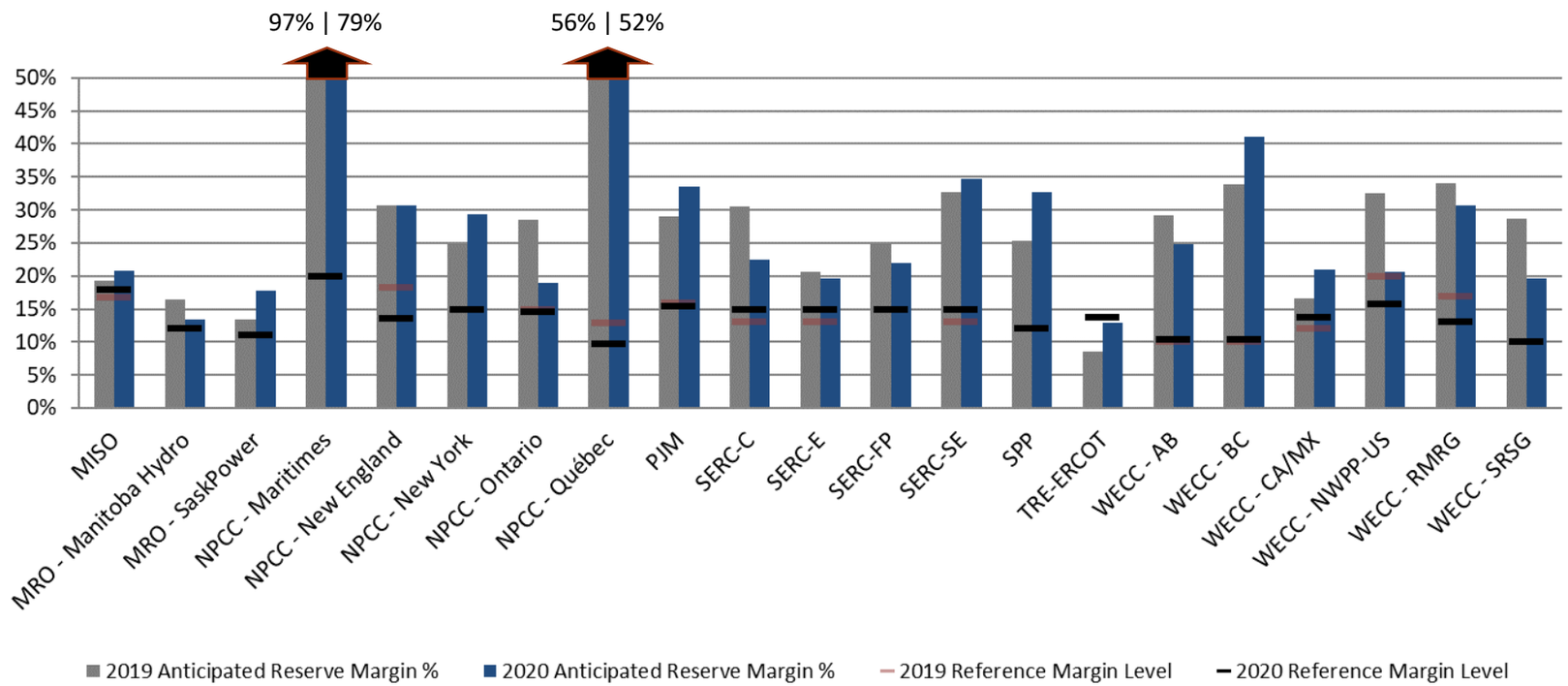


Figure 2: Summer 2019 to Summer 2020 Anticipated Reserve Margins Year-to-Year Change

Internal Demand

The changes in forecasted Net Internal Demand for each assessment area are shown in **Figure 3**.[5] Assessment areas develop these forecasts based on historic load and weather information as well as other long-term projections.

Most assessment area demand projections in this assessment have not been decreased to account for COVID-19 mitigation measures. Although government and societal responses to halt the spread of the coronavirus (i.e., shelter-in-place orders, minimal travel, and restrictions on public gatherings) have resulted in near-term decreased electricity demand, impact projections for summer are difficult to forecast. ERCOT is an exception, where planners reduced the pre-seasonal peak demand forecast by 1,496 MW but still anticipate potentially record-setting peak demand. The demand projections used in **Figure 3** and elsewhere throughout this report are likely higher than would be expected with pandemic mitigation completely factored in.

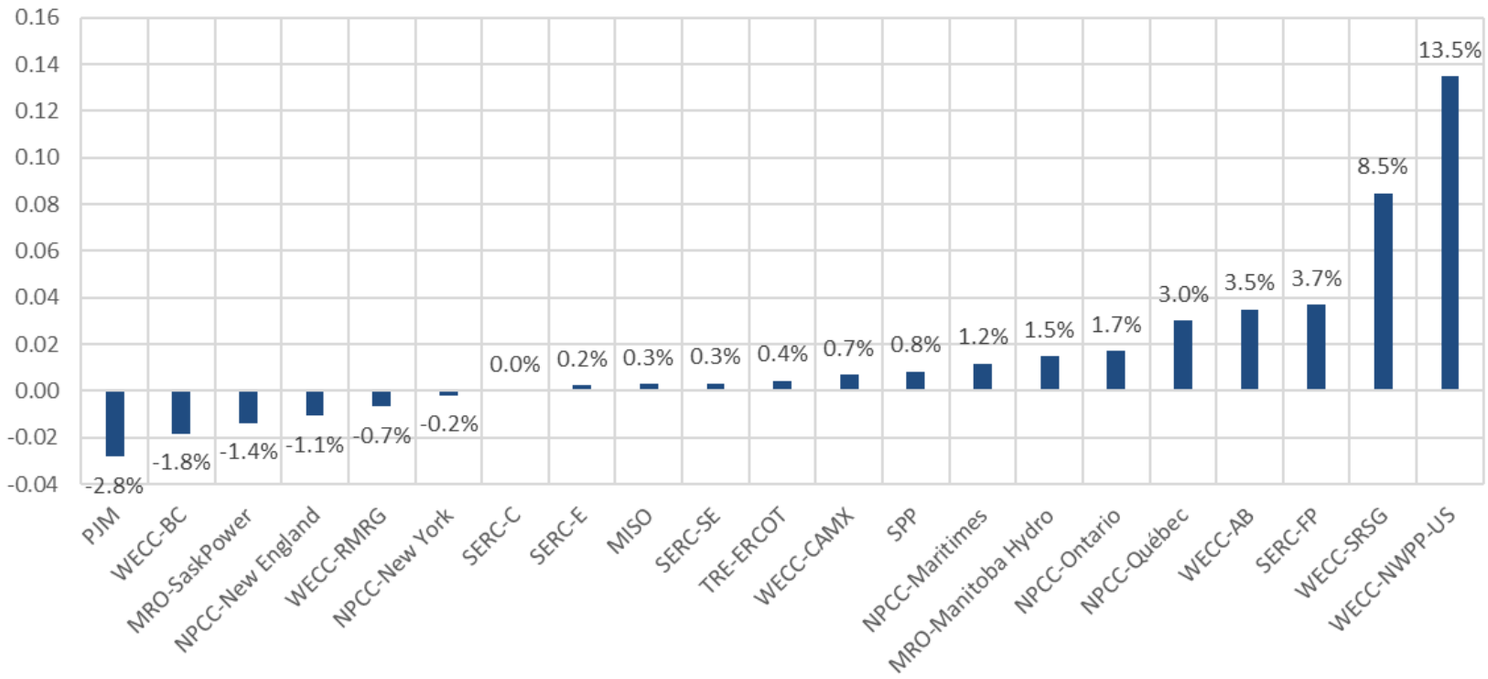


Figure 3: Change in Net Internal Demand: 2020 Summer Forecast Compared to 2019 Summer Forecast

[5] Changes in modeling and methods may also contribute to year-to-year changes in forecasted net internal demand projections.

Pandemic Preparedness and Operational Assessment—Summer 2020

The global health crisis has elevated the electric reliability risk profile due to potential workforce disruptions, supply chain interruptions, and increased cyber security threats. In April, NERC released its *Pandemic Preparedness and Operational Assessment – Spring 2020* (special report) to advise electricity stakeholders of the reliability considerations and assess the operational preparedness of the BPS owners and operators during pandemic conditions in April and May 2020. In its special report, NERC did not identify any specific threat or degradation to the reliable operation of the BPS for the spring time frame. The ERO continues to assess risks and conditions and is pursuing all available avenues to continue coordination with federal, state, and provincial regulators as well as work with industry to identify reliability implications and lessons learned.

Increased Reliability Risk Profile by Operating Period

Spring 2020	Summer 2020	Long-Term
• No specific reliability issue identified • Potential workforce disruptions • Supply chain interruption • Increased cyber security threat and monitoring • Different system conditions including lower demands and higher voltages. • System operators under sequester • Noncritical staff are remote	• Continued potential for workforce disruptions; support service disruption • Potential equipment and fuel supply chain disruptions • Deferred generation maintenance and other factors impacting unit availability • Generation in-service dates	• Potential changes to generation and transmission in-service dates • Increased remote operation of non-critical staff • Changes to pandemic preparedness and operating plans based on lessons learned Note: a more granular assessment will be Included in NERC's 2020 Long-Term Reliability Assessment

Since the start of the widening coronavirus infection in North America in February 2020, registered entities have taken steps from pandemic plans and industry advisories to maintain the reliability and security of the BPS. In March 2020, the Electricity Subsector Coordinating Council (ESCC) issued the first version of the *ESCC Resource Guide*[6] as a resource for electric power industry leaders to guide informed localized decisions in response to the COVID-19 global health emergency; it is updated on a regular basis as new approaches, planning considerations, and issues develop. The guide highlights data points, stakeholders, and options to consider in making decisions about operational status while protecting the health and safety of employees, customers, and communities. Sharing experiences and expertise helps users of the guide to make independent, localized decisions aimed at reducing negative impacts to the continent's power supply during the COVID-19 global pandemic. In addition to immediate measures designed to protect critical operations, personnel, and functions, entities are working to minimize risk to resource and BPS equipment availability, assure fuel supplies, and prepare operating personnel for peak season.

Maintenance Preparations for Summer Impacted

Since electricity demand is lower in a typical spring season than peak summer and winter periods, Transmission and Generator Owners normally have the opportunity to schedule maintenance and address training needs. Pandemic response and mitigation plans at national, state, provincial, and local levels can impact maintenance efforts by disrupting the flow of personnel and supply chains. Some delays to transmission projects due to disrupted travel of specialized contractors has been reported. To avoid the risk of failing to complete maintenance on time, some owners and operators have deferred or cancelled preseason maintenance in response to pandemic-related issues as can be seen by the MISO area example in **Figure 4**.

[6] https://www.electricitysubsector.org/

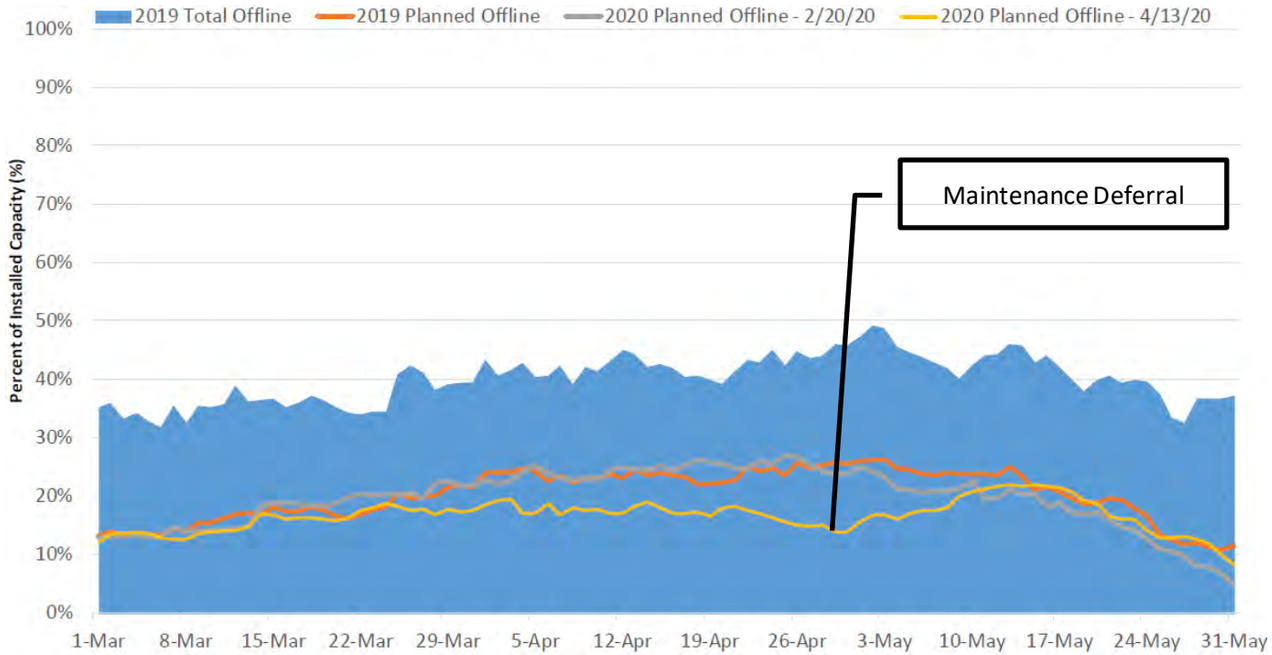


Figure 4: Generation Capacity Planned to be Off-line in MISO through May 31, 2020 (Scheduled February 20 and April 13, 2020).

In ERCOT, planners observed a higher-than-normal volume of generator maintenance outages in late March/early April possibly due to Generator Owners accelerating maintenance schedules to get ahead of potential supply chain or personnel delays. Planners and operators continue to manage schedules of equipment outages into the summer season to ensure sufficient resource availability and transmission system readiness. Maintenance that would have been performed prior to summer but is deferred can increase the risk of forced outages.

Operators in areas where a large portion of generators have deferred maintenance could experience higher-than-expected forced outages that could lead to generation supply deficiencies during periods of peak demand. NERC is implementing codes for its Generator Availability Data System (GADS) that will support collection of data on outages with pandemic causes for use in analyzing reliability impacts in later months.[7]

Electricity supply risk can be compounded by risks to the generator and to their supply of fuel. Natural-gas-fired generators can be at risk to fuel supply infrastructure disruption from mechanical or other issues; planners and operators in areas with impacted preseason maintenance are implementing measures to mitigate such risks. For example, in ISO-NE, the Electric/Gas Operations Committee has been conducting weekly meetings to determine and assess pandemic impacts to pipelines. The ISO has also increased surveying of generator owners and operators to assess outage risks.

[7] Information about GADS: https://www.nerc.com/pa/RAPA/gads/Pages/GeneratingAvailabilityDataSystem-(GADS).aspx

Demand Impacts Vary and Cause Forecast Uncertainty

The pandemic is negatively impacting electricity demand in many parts of North America just as it has elsewhere around the world. Prior to summer, when government stay-at-home orders and societal response were at their highest, some areas reported as much as 15% drop off in peak demand. However, these observed demand impacts varied across North America and in some areas were negligible. Throughout the pandemic, many independent system operators and regional transmission operators have periodically reported on demand impacts.[8] In most areas, weather continues to be the predominant factor in electricity demand. Diminished peak demand resulting from pandemic does not pose any meaningful risk to reliability for the summer season.

Many areas are experiencing variations in hourly load shapes as a result of changing societal behaviors and mechanisms implemented to halt the spread of the coronavirus. In general, these areas are seeing below-normal ramp in demand in morning hours and lower evening demand as can be seen in **Figure 5**. Changes to pre-pandemic patterns can affect accuracy of day-ahead demand forecasts that are relied upon to ensure resources are available for each hour of the day. In recent years, demand and resource forecasting has become more complex—and more critical—as the generation resource mix has changed to include higher levels of variable generation, and load shape has changed with increasing solar photovoltaic (PV) resources. When operating entities began observing discrepancies between predicted and actual demand as a result of pandemic behavior, many instituted measures designed to improve the accuracy of forecasts made available to system operators. In MISO and other ISOs, support teams have increased the frequency of short-term demand forecast simulations.

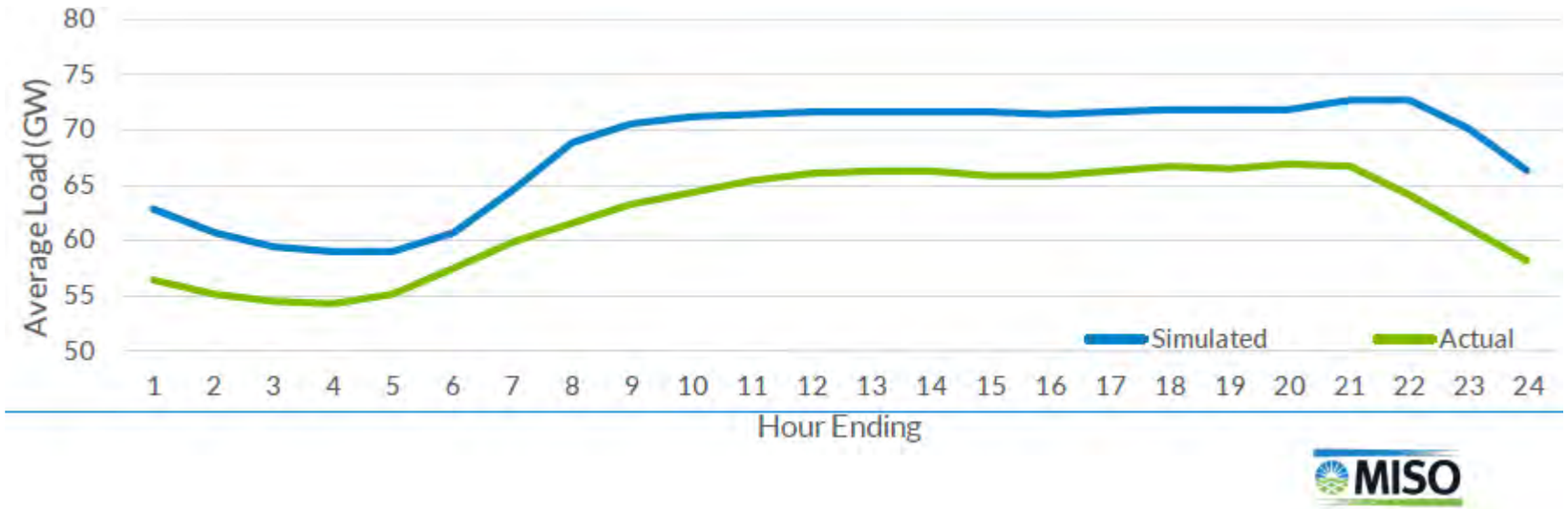


Figure 5: Average Simulated and Actual Load in MISO Area for April 4–10, 2020

[8] For example, see reports from ERCOT and CAISO: http://www.caiso.com/Documents/COVID-19-Impacts-ISOLoadForecast-Presentation.pdf
http://www.ercot.com/content/wcm/lists/200201/ERCOT_COVID-19_Analysis_FINAL.pdf

Potential Demand and Resource Challenges for System Operators

Where pandemic restrictions persist through the summer, system operators could encounter difficult system characteristics, such as increased impact of DERs on load profiles, distribution reverse power flows, higher than usual operating voltages, and minimum demands at all-time lows. Operating challenges such as these need to be addressed in real-time and often by using complex tools for studying dynamic system conditions.

The effect of distributed energy resources (DERs) on system performance can become more pronounced as synchronous generation can be replaced on the system during periods of lower minimum demand; operators could face challenges in maintaining sufficient amounts of frequency-responsive reserves necessary to regulate or arrest changes in frequency. Typically, DER effects on the system are more pronounced in the spring when milder temperatures reduce air conditioning load and increase efficiency in solar PV modules. With potentially lower demand on the system as a result of the pandemic, these conditions could extend into early summer. In areas with higher DER penetration (e.g., California and North Carolina), minimum loads and reverse power flows from the distribution system can cause some challenges for system operators.

Operators in some areas may also have to contend with how a reduction in industrial and commercial loads could affect operating strategies and emergency plans. The potential lack of industrial and commercial load could alter underfrequency or undervoltage load shedding plans that rely on tripping these loads as well as demand response programs that may be relied on to support emergency operations.

Operating Reliability Considerations

- Increased uncertainty in demand projections and daily use
- Potential for increased forced outages due to deferred maintenance, staff unavailability, or limited supplies and/or fuel
- Higher than usual operating voltages
- Light load conditions
- Reverse power flow and increased penetration levels of DERs
- Potential for reduced effectiveness in underfrequency/voltage load shedding schemes as industrial and commercial load may not be online

Utility Crews and Operators Must Stay Postured for Reliability, Security, and Resilience

As the coronavirus crisis unfolds in the lead up to summer, the industry is preparing to operate with a significantly smaller workforce, an encumbered supply chain, and limited support services for an extended and unknown period of time. Vigilance to cyber security threats intensifies as risks are elevated due to a greater reliance on remote working arrangements. The business continuity and pandemic plans developed by the different operating entities are designed to protect the people working for them and to ensure critical electricity operations and infrastructure are supported properly throughout an emergency.

Protecting critical electric industry workforce during the COVID-19 pandemic remains a priority for reliability and resilience. System and Generator Operators have implemented operating postures and personnel restrictions prescribed by their pandemic plans in order to protect essential personnel and support reliable operations. Many of these measures will need to be maintained for the foreseeable future. There is a continuing risk that control centers or plants could be temporarily shut down if a significant number of operators or plant employees test positive for COVID-19 despite preparedness efforts, including employee sequestration. As of April, many entities had begun developing return to work plans; however, the majority of entities indicated that they expected to maintain protective protocols for operating personnel through summer and beyond. When relaxations can be implemented, operators will likely need to stay postured to return to heightened protections if warranted by public health conditions.

An important component of BPS resilience and recovery from hurricanes and major storms is the effective mutual assistance rendered by organizations from outside the storm-affected areas. The comprehensive plans in place to rapidly deploy support teams and equipment take on even greater complexity for the 2020 North American hurricane season (May–November) due to the need to safeguard personnel from coronavirus infection. In April, the ESCC updated its *Resource Guide* to provide lessons learned from the experience of the utilities, electric cooperatives, and investor-owned electric companies affected by a series of storms in late March and early April of this year. Lessons learned include considerations for maintaining social distancing at all times, planning for personnel protection equipment needs, and increased need for local logistical and coordination personnel to support a decentralized response.[9]

[9] See *ESCC Resource Guide*, Version 7, April 27, 2020, p. 47–48.

Cyber Security Risk and Information Sharing

Electricity and other critical infrastructure sectors face elevated cyber security risks arising from the COVID-19 pandemic in addition to ongoing risks. Opportunistic actors are attempting to find and exploit new vulnerabilities that arise as entities shift work processes and locations to maintain business continuity. The Electricity Infrastructure Sharing and Analysis Center (E-ISAC) continues to exchange information with its members and has posted communications and guidance from the ESCC and from government partners, and other advisories on its Portal; members are encouraged to check in regularly to receive updates. The E-ISAC also continues to provide information regarding emerging cyber threats; these include attacks on conferencing and remote access infrastructure, disinformation, and spear phishing campaigns attempting to harvest credentials and other information. Members are encouraged to actively share information regarding threats and other malicious activities with the E-ISAC to enable broader communication with other sector participants and government partners.

Operational Risks Highlighted for Summer 2020

Seasonal Operational Risk Assessments of Resource and Demand Scenarios

Areas can face energy shortfalls despite having Planning Reserve Margins that exceed Reference Margin Levels. Operating resources may be insufficient during periods of peak demand for reasons that could include generator scheduled maintenance, forced outages due to normal and more extreme weather conditions and loads, and low-likelihood conditions that affect generation resource performance or unit availability, including constrained fuel supplies. The **Regional Assessment Dashboards** section in this report includes a seasonal risk scenario for each area that illustrates potential variation in resource and load as well as the potential effects that operating actions can have to mitigate shortfalls in operating reserves when insufficiencies occur. **Figure 6** shows an example seasonal risk assessment for the Southwest Power Pool (SPP) area that NERC developed using SRA data. A description of resource and demand variables is found in **Table 1**.

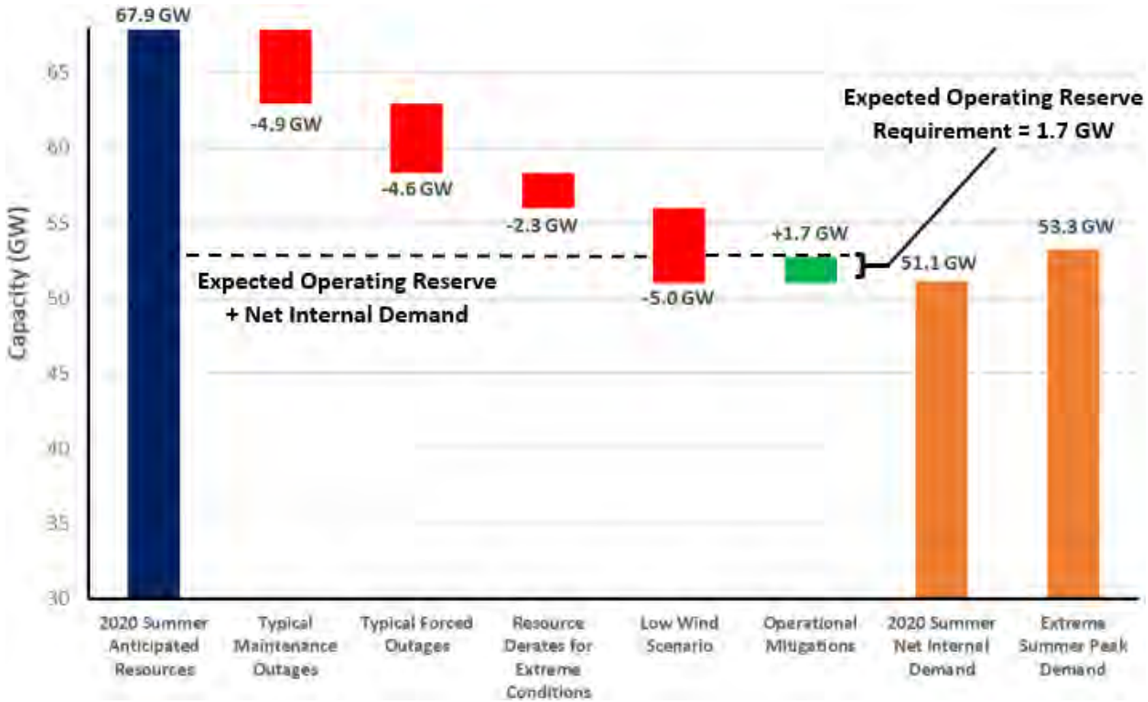


Figure 6: SPP Assessment Area Seasonal Risk Assessment

About the Seasonal Risk Assessment

The operational risk analysis shown in **Figure 6** provides a deterministic scenario for understanding how various factors affecting resources and demand can combine to impact overall resource adequacy. Adjustments are applied cumulatively to anticipated capacity, such as reductions for typical generation outages (maintenance and forced not already accounted for in anticipated resources) and additions that represent the quantified capacity from operational tools, if any, that are available during scarcity conditions but have not been accounted for in the SRA reserve margins.

Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The effects from low-probability, extreme events are also factored in through additional resource derates or extreme resource scenarios and extreme summer peak load conditions. Because the seasonal risk scenario shows the cumulative impact resulting from the occurrence of multiple low-probability events, the overall likelihood of the scenario is very low. An analysis similar to the SPP seasonal risk scenario in **Figure 6** can be found for each assessment area in the **Regional Assessment Dashboards** section of this report.

The seasonal risk assessment for the SPP assessment area shows that resources are available to meet peak summer demand, including normally hot and humid summer conditions. However, extreme heat and summer conditions, such as those associated with record-setting temperatures, could increase demand and reduce generator performance enough to cause operating emergencies. A low-output wind generation event, though rare, could lead to operating actions, including conservative operations plans and EEA declarations, to manage resources and demand. Despite anticipated resources in excess of Reference Margin Levels as shown in **Figure 1**, operators in SPP and other areas of North America can face resource constraints during extreme summer weather.

During the past two summers, system operators in SPP needed to take operating actions, including issuing one EEA in August 2019, to address resource shortfalls. In some instances, operators were responding to higher than expected planned and forced outages coupled with real time forecasting errors for load and wind. SPP has established operational mitigation teams and developed enhanced processes and procedures to support operators in maintaining real time reliability.

Table 1: Resource and Demand Variables in the SPP Seasonal Risk Assessment

Resource Scenarios	
Typical Maintenance Outages	Typical maintenance outages refer to an estimate of generation resources that will be out for maintenance during peak demand conditions. SPP calculated a value of 4,926 MW based on historical averages.
Typical Forced Outages	Typical forced outages refer to an estimate of generation resources that will experience forced outage during peak load conditions. SPP calculated a value of 4,638 MW based on historical averages.
Resource Derates for Extreme Conditions (Low-likelihood)	An estimated capacity derate due to extreme conditions is calculated and used for a low-likelihood resource scenario. The derate accounts for reduced capacity contributions due to generator performance in extreme conditions. SPP calculated a capacity derate of 2,276 MW for thermal generation due to extreme conditions.
Low-Wind Scenario (Low-likelihood)	The low-wind scenario is used to analyze the impact of low-likelihood weather conditions that severely reduce output from wind generation resources. A capacity adjustment of 5,017 MW is based on a low wind generator output historical event observed by system operators during summer peak conditions.
Operational Mitigations	SPP estimates that certain operational mitigations can contribute 1,700 MW of additional resources to support maintaining operating reserve requirements.
Demand Scenarios	
2020 Summer Net Internal Demand	Net internal demand is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour. It is based on historical average weather (i.e., forecasts for a 50/50 distribution).
Extreme Summer Peak Load	A seasonal load adjustment (2,313 MW) is added to 2020 Net Internal Demand to account for extreme weather conditions. The adjustment is based on a 90/10 statistical extreme load forecast.

Seasonal Risk Assessments for Other Areas

Seasonal risk scenarios for each assessment area are presented in the **Regional Assessment Dashboards** section of this report. Potential extreme generation resource outages and peak loads that can accompany extreme hot or humid weather may result in reliability risks in MISO, SPP, and ERCOT as well as the Canadian provinces of Manitoba, Saskatchewan, and the Maritimes. Parts of the system within the WECC area, including California ISO, could also experience resource shortfalls in low-likelihood resource derate scenarios. Under studied conditions for these areas, grid operators would need to employ operating mitigations or EEAs to obtain resources necessary to meet extreme peak demands.

Wildfire Risk Potential and BPS Impacts

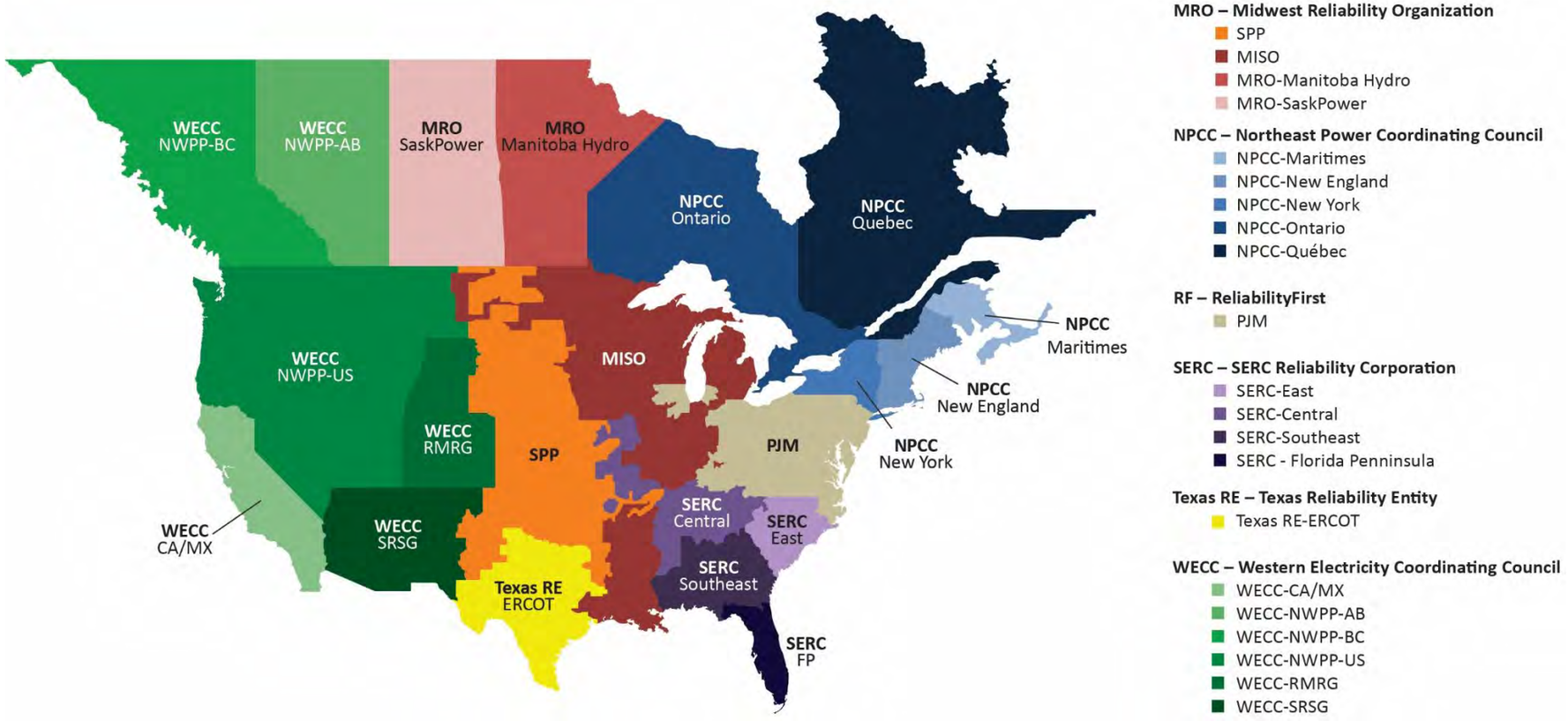
Government agencies predict normal to below-normal wildfire risk at the start of summer for the West Coast of the United States and the southwestern states. However, the latest three-month *Seasonal Fire Assessment and Outlook* published by the National Interagency Fire Center, Natural Resources Canada, and National Meteorological Service in Mexico warns that the trend toward warmer, drier weather could lead to above normal wildland fire potential in Northern California, Oregon, and Washington beginning in June.[10] Across most of western Canada, weather patterns and forecasts also suggest increased potential for wildland fires.

Operation of the BPS can be impacted in areas where wildfires are active as well as areas where there is heightened risk of wildfire ignition due to weather and ground conditions. Wildfire prevention planning in California and other areas include power shut-off programs in high fire-risk areas. When conditions warrant implementing these plans, power lines, including transmission-level lines, may be preemptively de-energized in high fire-risk areas to prevent wildfire ignitions. Other wildfire risk mitigation activities include implementing enhanced vegetation management, equipment inspections, system hardening, and added situational awareness measures.

[10] See *North American Seasonal Fire Assessment and Outlook*, May 2020: https://www.predictiveservices.nifc.gov/outlooks/NA_Outlook.pdf

Regional Assessment Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the Regional Entities on an assessment area basis.

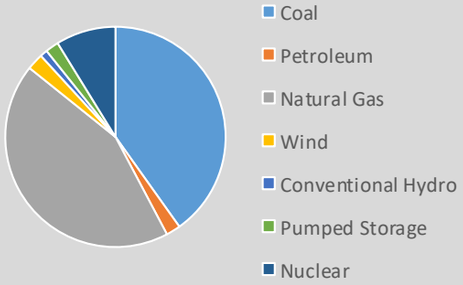




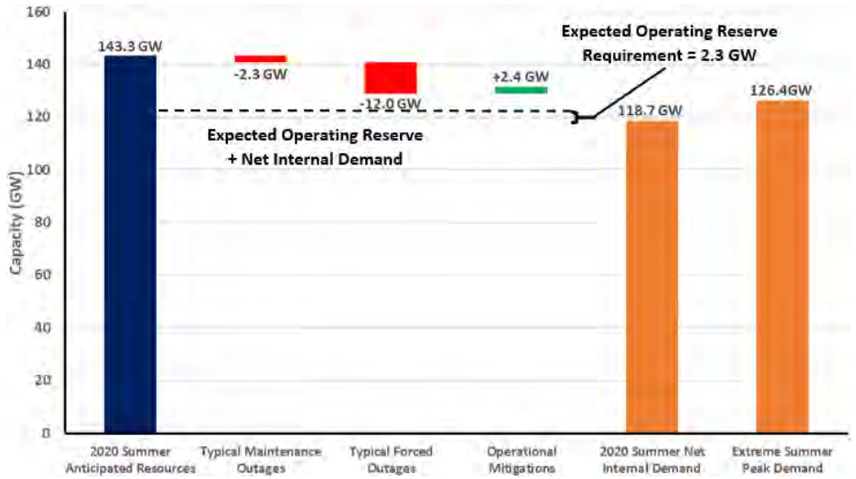
MISO

The Midcontinent Independent System Operator, Inc. (MISO) is a not-for-profit, member-based organization administering wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency.

MISO manages energy, reliability, and operating reserve markets that consist of 36 local Balancing Authorities and 394 market participants that serves approximately 42 million customers. Although parts of MISO fall in three NERC Regions, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.



Seasonal Risk Scenario



MISO Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2019 SRA**	**2020 SRA**	**2019 vs. 2020 SRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	124,744	124,866	0.1%
Demand Response: Available	6,385	6,172	-3.3%
Net Internal Demand	118,359	118,694	0.3%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	139,220	140,636	1.0%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,955	2,795	42.9%
Anticipated Resources	141,175	143,430	1.6%
Existing-Other Capacity	591	290	-50.9%
Prospective Resources	141,766	143,720	1.4%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	19.3%	20.8%	1.5
Prospective Reserve Margin	19.8%	21.1%	1.3
Reference Margin Level	16.8%	18.0%	1.2

The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels, with adjustments for normal and extreme conditions. MISO determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized below. See the **Data Concepts and Assumptions** for more information about this table and chart.

Risk Scenario Summary

Observation:

Resources meet operating reserve requirements under normal demand and outage scenarios. Extreme summer peak demand or outages could result in a need to employ operating procedures to mitigate resource shortfall.

Scenario Assumptions

- **Extreme Peak Load:** 90/10 forecast
- **Outages:** Average from highest peak hour over the past five summers

Highlights

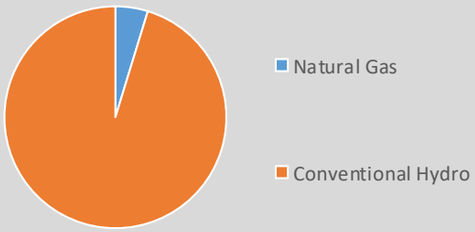
- Summer scenarios with high resource outages and high demand may require use of load modifying resources during peak periods as load modifying resources become an increasingly important segment of MISO's resource portfolio.
- Though MISO remains resource adequate for the 2020 summer, some areas may be resource and import constrained presenting local operating challenges.
- Near-term impacts of COVID-19 have resulted in generally lower loads and shifted morning and evening peaks to later hours. It is unclear how observed trends will change through the summer months.



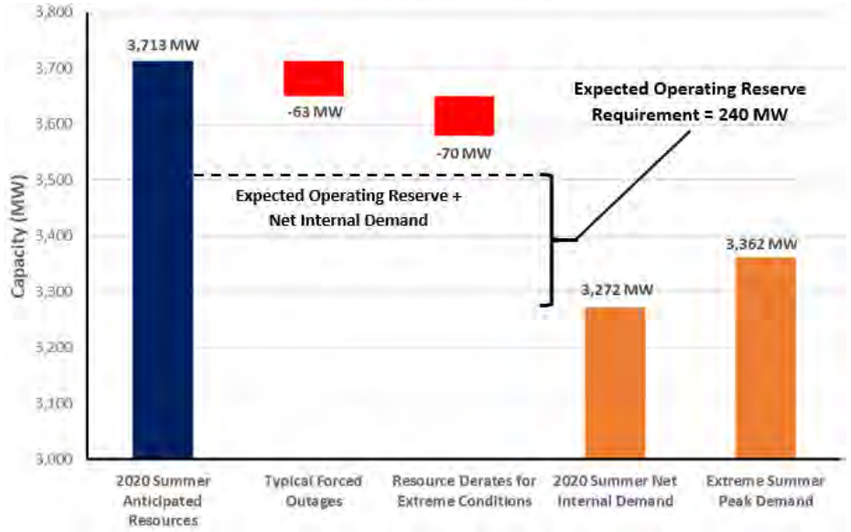
MRO-Manitoba Hydro

Manitoba Hydro is a provincial crown corporation that provides electricity to about 580,000 customers throughout Manitoba and natural gas service to about 282,000 customers in various communities throughout Southern Manitoba. The Province of Manitoba has a population of about 1.3 million people in an area of 250,946 square miles.

Manitoba Hydro is winter peaking. No change in the footprint area is expected during the assessment period. Manitoba Hydro is its own Planning Coordinator and Balancing Authority. Manitoba Hydro is a coordinating member of MISO. MISO is the Reliability Coordinator for Manitoba Hydro.



Seasonal Risk Scenario



MRO-Manitoba Hydro Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2019 SRA**	**2020 SRA**	**2019 vs. 2020 SRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	3,224	3,272	1.5%
Demand Response: Available	0	0	-
Net Internal Demand	3,224	3,272	1.5%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	5,161	5,239	1.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-1,408	-1,526	8.4%
Anticipated Resources	3,753	3,713	-1.1%
Existing-Other Capacity	215	125	-41.6%
Prospective Resources	3,968	3,838	-3.3%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	16.4%	13.5%	-2.9
Prospective Reserve Margin	23.1%	17.3%	-5.8
Reference Margin Level	12.0%	12.0%	0.0

The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. MRO-Manitoba determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below. See the **Data Concepts and Assumptions** for more information about this table and chart.

Risk Scenario Summary

Resources meet operating reserve requirements under normal demand and outage scenarios.

Scenario Assumptions

- **Extreme Peak Demand:** All-time highest peak load
- **Outages:** Based on historical operating experience
- **Extreme Derates:** Thermal units derated for extreme temperature where appropriate.

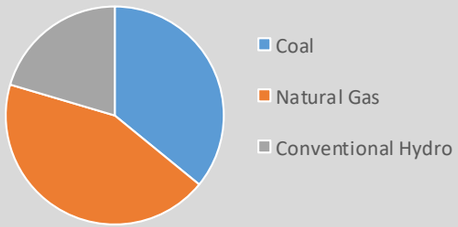
Highlights

- Manitoba Hydro has implemented measures to minimize coronavirus impact risk to operations. While the COVID-19 Pandemic is expected to be present over the summer assessment period, an impact on BPS reliability is not anticipated.
- Reservoir storage levels are above average and more than adequate to withstand the design-basis drought conditions.

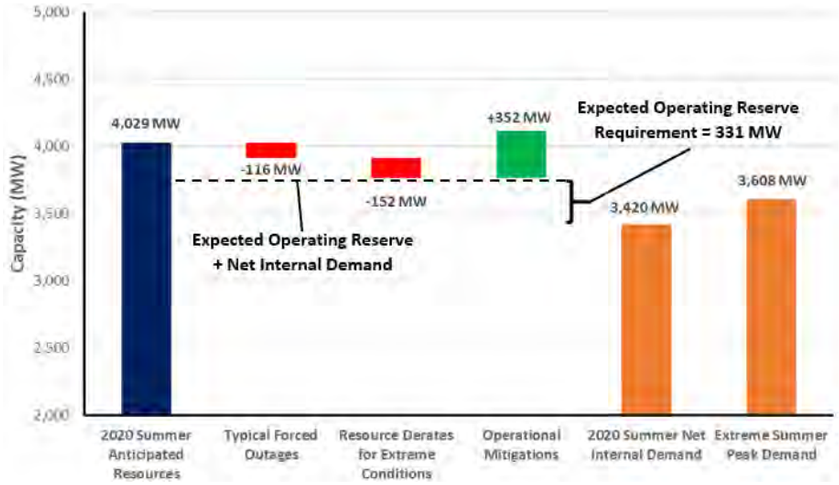


MRO-SaskPower

Saskatchewan is a province of Canada and comprises a geographic area of 651,900 square kilometers (251,700 square miles) with approximately 1.1 million people. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the Planning Coordinator and Reliability Coordinator for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial crown corporation, under provincial legislation, and is responsible for the reliability oversight of the Saskatchewan Bulk Electric System (BES) and its interconnections.



Seasonal Risk Scenario



MRO-SaskPower Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2019 SRA**	**2020 SRA**	**2019 vs. 2020 SRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	3,553	3,480	-2.1%
Demand Response: Available	85	60	-29.4%
Net Internal Demand	3,468	3,420	-1.4%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	3,907	3,904	-0.1%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	25	125	400.0%
Anticipated Resources	3,932	4,029	2.5%
Existing-Other Capacity	0	0	-
Prospective Resources	3,932	4,029	2.5%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	13.4%	17.8%	4.4
Prospective Reserve Margin	13.4%	17.8%	4.4
Reference Margin Level	11.0%	11.0%	0.0

The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. MRO-SaskPower determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below. See the **Data Concepts and Assumptions** for more information about this table and chart.

Risk Scenario Summary

Resources meet operating reserve requirements under normal scenarios. Extreme summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, and short-term load interruption.)

Scenario Assumptions

- **Extreme Peak Load:** Peak demand with lighting and all large consumer loads
- **Maintenance Outages:** Estimated based on average maintenance outages for June, July, August, and September for 2019
- **Forced Outages:** Estimated using SaskPower forced outage model
- **Extreme Derates:** Derate on natural gas units based on historic data and manufacturer data

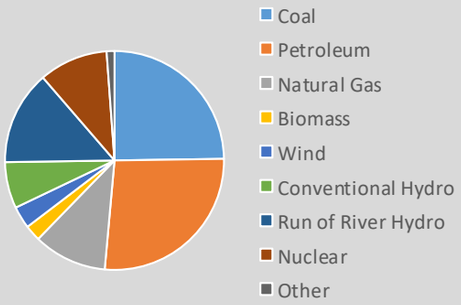
Highlights

- Saskatchewan experiences high load in summer as a result of extreme hot weather.
- SaskPower conducts an annual summer joint operating study with Manitoba Hydro with inputs from Basin Electric (North Dakota) and prepares operating guidelines for any identified issues.
- The risk of operating reserve shortage during peak load times or EEAs could increase if large generation forced outage occurs during peak load times in the end of August to early October 2020 when 641 MW of SaskPower's natural gas generating station is off-line for overhaul maintenance.

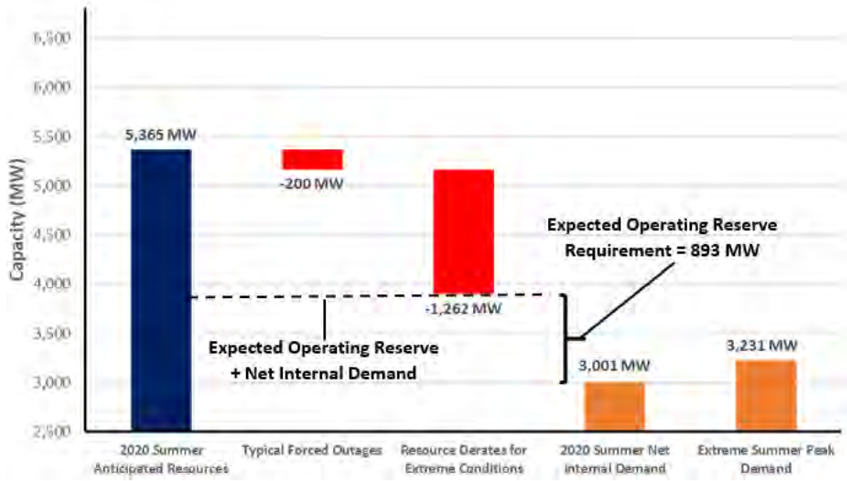


NPCC-Maritimes

The Maritimes assessment area is a winter-peaking NPCC subregion that contains two Balancing Authorities. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, and Prince Edward Island, and the northern portion of Maine that is radially connected to the New Brunswick power system. The area covers 58,000 square miles with a total population of 1.9 million.



Seasonal Risk Scenario



NPCC-Maritimes Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2019 SRA**	**2020 SRA**	**2019 vs. 2020 SRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	3,255	3,370	3.5%
Demand Response: Available	289	369	27.7%
Net Internal Demand	2,966	3,001	1.2%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	5,842	5,312	-9.1%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	0	53	0.0%
Anticipated Resources	5,842	5,365	-8.2%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	5,842	5,365	-8.2%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	97.0%	78.8%	-18.2
Prospective Reserve Margin	97.0%	78.8%	-18.2
Reference Margin Level	20.0%	20.0%	0.0

The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. NPCC-Maritimes determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below. See the **Data Concepts and Assumptions** for more information about this table and chart.

Risk Scenario Summary

Resources meet operating requirements under normal peak load scenario. Extreme summer peak load and outage conditions could result in the need to employ operating mitigation to manage resource shortfall.

Scenario Assumptions

- **Extreme Peak Load:** 90/10 forecast
- **Outages:** Based on historical operating experience
- **Extreme Derates:** An extreme, low-likelihood scenario is used whereby thermal units are derated for extreme temperature and all wind unit capacity is unavailable

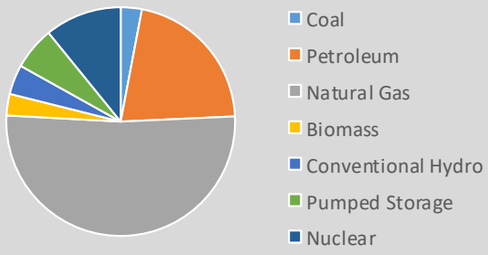
Highlights

- The Maritimes area has not identified any operational issues that are expected to impact system reliability. If an event was to occur, there are emergency operations procedures in place. All of the area's declared firm capacity is expected to be operational for the summer operating period.
- As part of the planning process, dual-fueled units will have sufficient supplies of heavy fuel oil (HFO) on-site to enable sustained operation in the event of natural gas supply interruptions.
- The effects of the COVID-19 pandemic on load patterns, energy use, and peak demands will continue to be evaluated as the pandemic evolves.
- The Maritimes are evaluating contingency plans for transmission, distribution and generation planned work, planned maintenance and forced outages to proceed conservatively while mitigating short term and longer term reliability risks.

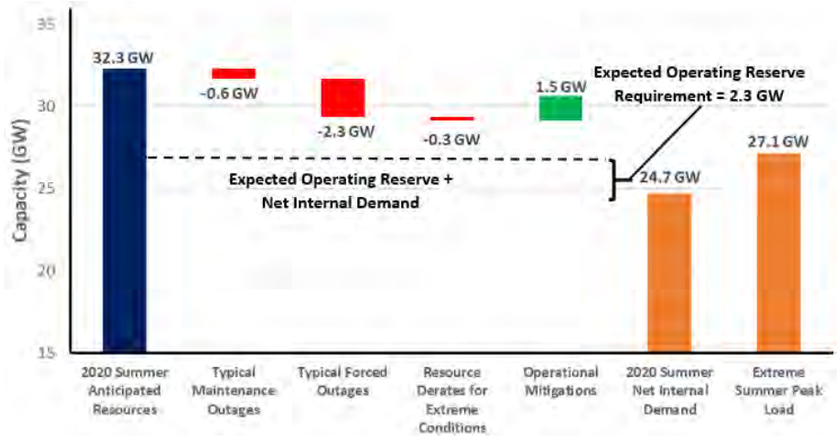


NPCC-New England

ISO New England (ISO-NE) Inc. is a regional transmission organization that serves Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. It is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, and it also administers the area's wholesale electricity markets and manages the comprehensive planning of the regional BPS. The New England regional electric power system serves approximately 14.5 million people over 68,000 square miles.



Seasonal Risk Scenario



NPCC-New England Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2019 SRA**	**2020 SRA**	**2019 vs. 2020 SRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	25,323	25,158	-0.7%
Demand Response: Available	340	443	30.3%
Net Internal Demand	24,983	24,715	-1.1%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	30,144	30,791	2.1%
Tier 1 Planned Capacity	1,185	0	-100.0%
Net Firm Capacity Transfers	1,328	1,510	13.7%
Anticipated Resources	32,657	32,301	-1.1%
Existing-Other Capacity	704	324	-54.0%
Prospective Resources	33,361	32,625	-2.2%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	30.7%	30.7%	0.0
Prospective Reserve Margin	33.5%	32.0%	-1.5
Reference Margin Level	18.3%	18.3%	0.0

The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. NPCC-New England determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below. See the **Data Concepts and Assumptions** for more information about this table and chart.

Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** 90/10 Forecast
- **Outages:** Based on weekly averages
- **Operating Mitigations:** Based on ISO-NE operating procedures

Highlights

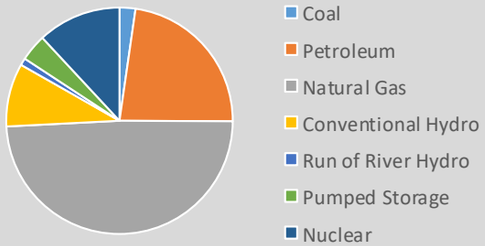
- The New England Area expects to have sufficient resources to meet the 2020 summer peak demand forecast of 25,158 MW for the week beginning July 5, 2020, with a projected net margin of 3,197MW (12.7%). The 2020 summer demand forecast is 165 MW (0.7%) less than the 2019 summer forecast of 25,323 MW and takes into account the demand reductions associated with energy efficiency, load management, behind-the-meter photovoltaic (BTM-PV) systems, and distributed generation.
- With residents and businesses across New England changing their behavior in response to the COVID-19 pandemic, ISO New England is seeing a decline in system demand of approximately 3–5% compared to what would normally be expected under weather conditions in the area. These percentages may change over time.
- In addition to overall declines in consumer demand, these societal changes are also affecting demand patterns across the region. Though the pandemic is affecting energy use, weather conditions remain the primary drivers of system demand. ISO-NE will continuously monitor these ever-changing trends in load patterns and make the appropriate adjustments to calculate an accurate load forecast. The area's power system continues to remain reliable.



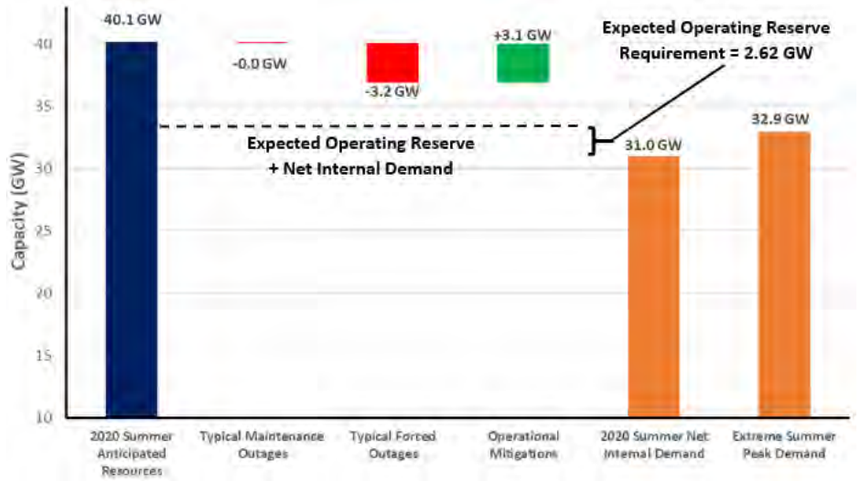
NPCC-New York

The New York Independent System Operator (NYISO) is the only Balancing Authority within the state of New York. NYISO is a single-state ISO that was formed as the successor to the New York Power Pool—a consortium of the eight IOUs—in 1999. NYISO manages the New York State transmission grid that encompasses approximately 11,000 miles of transmission lines, more than 47,000 square miles, and serving the electric needs of 19.5 million people. New York experienced its all-time peak load of 33,956 MW in the summer of 2013.

The NERC Reference Margin Level is 15%. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. However, New York requires load serving entities to procure capacity for their loads equal to their peak demand plus an IRM. The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). NYSRC approved the 2020–2021 IRM at 18.9%.



Seasonal Risk Scenario



NPCC-New York Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2019 SRA**	**2020 SRA**	**2019 vs. 2020 SRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	32,382	32,296	-0.3%
Demand Response: Available	1,309	1,282	-2.1%
Net Internal Demand	31,073	31,014	-0.2%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	37,304	38,475	3.1%
Tier 1 Planned Capacity	27	101	274.8%
Net Firm Capacity Transfers	1,452	1,562	7.6%
Anticipated Resources	38,783	40,138	3.5%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	38,783	40,138	3.5%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	24.8%	29.4%	4.6
Prospective Reserve Margin	24.8%	29.4%	4.6
Reference Margin Level	15.0%	15.0%	0.0

The table and chart above provide potential seasonal peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. NPCC-New York determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below. See the **Data Concepts and Assumptions** for more information about this table and chart.

Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Demand:** 90/10 load forecast with demand response adjustments
- **Extreme Derates:** Near-zero MW due to summer peaking area
- **Typical Outages:** Based on scheduled maintenance and GADS forced outage data
- **Operational Mitigation:** 3.1 GW based on operational/emergency procedures in NYISO *Emergency Operations Manual*

Highlights

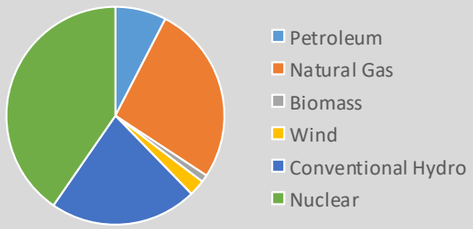
- NYISO is not anticipating any operational issues in the New York control area for the upcoming summer. Adequate capacity margins are anticipated and existing operating procedures are sufficient to handle any issues that may occur.
- New York requires load serving entities to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is determined and approved annually by the New York State Reliability Council (NYSRC). NYSRC approved a 2020–2021 IRM of 18.9%. The IRM meets the NPCC and NYSRC criterion of a loss of load expectation of no greater than 0.1 days per year. Its calculation is based on a study that accounts for the forced outage rates of thermal generators, the peak load forecast, the load forecast uncertainty, the actual hourly production data for wind and solar over the most recent five-year calendar period, long term capacity imports and exports, demand response programs derated to account for historic availability, various emergency operation procedures, and assistance from neighboring control areas. Historically since 2000, the IRM has ranged between 15.0% and 18.9%.



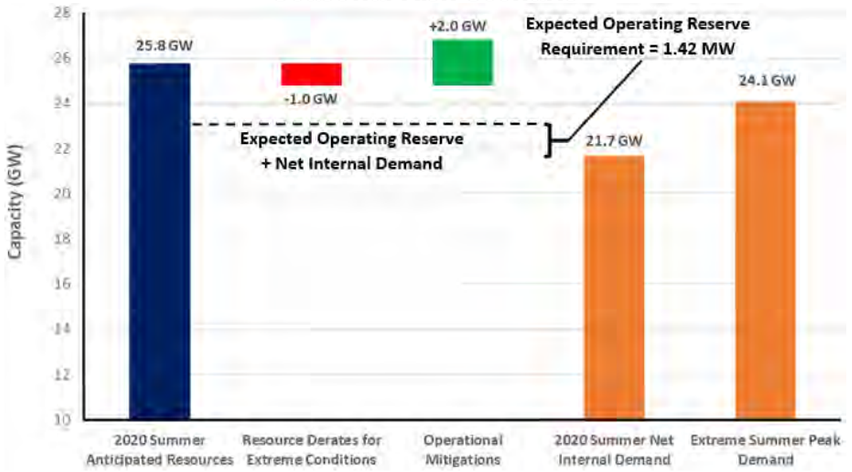
NPCC-Ontario

The Independent Electricity System Operator (IESO) is the Balancing Authority and Reliability Coordinator for the province of Ontario. In addition to administering the area's wholesale electricity markets, the IESO plans for Ontario's future energy needs. Ontario covers more than 415,000 square miles and has a population of more than 14 million. Ontario is interconnected electrically with Québec, MRO-Manitoba, statesin MISO (Minnesota and Michigan), and NPCC-New York.

Ontario IESO treats demand response as a resource for its own assessments while in the NERC assessment demand response is used as a load-modifier. As a result, the total internal demand, reserve margin, and Reference Margin Level values differ in IESO's reports when compared to NERC reports.



Seasonal Risk Scenario



NPCC-Ontario Resource Adequacy Data

Demand, Resource, and Reserve Margin	2019 SRA	2020 SRA	2019 vs. 2020 SRA
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	22,105	22,195	0.4%
Demand Response: Available	790	518	-34.5%
Net Internal Demand	21,315	21,677	1.7%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	26,581	25,719	-3.2%
Tier 1 Planned Capacity	924	49	-94.7%
Net Firm Capacity Transfers	-102	0	-100.0%
Anticipated Resources	27,403	25,768	-6.0%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	27,403	25,768	-6.0%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	28.6%	18.9%	-9.7
Prospective Reserve Margin	28.6%	18.9%	-9.7
Reference Margin Level	14.9%	14.6%	-0.3

The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. NPCC-Ontario determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below. See the **Data Concepts and Assumptions** for more information about this table and chart.

Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** Determined from the most severe historical weather
- **Extreme Derates:** Based on thermal unit derating curves and historical hydro performance for a low-water year
- **Operational Mitigation:** 2,000 MW imports assessed as available from neighbors

Highlights

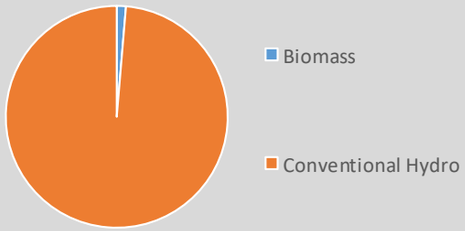
- The IESO expects to have sufficient generation supply for Summer 2020. Likewise, Ontario's transmission system is expected to continue to reliably supply province-wide demand throughout the summer season.
- Napanee Generating Station, a 994 MW natural-gas-fired plant, was added to Ontario's generation fleet in March 2020. The Darlington Nuclear Unit G2 (936 MW) is expected to return to service following refurbishment prior to summer.
- The year-on-year reduction in anticipated/prospective reserve margin is due to a greater number of nuclear units on refurbishment outage as well as reductions in demand response and hydroelectric contributions.
- The ongoing transmission outage of the phase angle regulator on the L33 circuit at the New York-St Lawrence interconnection continues to impact import and export capacity between Ontario and New York. The issue is being jointly managed by all involved parties.



NPCC-Québec

The Québec assessment area (Province of Québec) is a winter-peaking NPCC subregion that covers 595,391 square miles with a population of 8 million.

Québec is one of the four NERC Interconnections in North America; with ties to Ontario, New York, New England, and the Maritimes; consisting of either HVDC ties, radial generation, or load to and from neighboring systems.





NPCC- Québec Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2019 SRA**	**2020 SRA**	**2019 vs. 2020 SRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	21,005	21,635	3.0%
Demand Response: Available	0	0	0.0%
Net Internal Demand	21,005	21,635	3.0%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	34,303	34,771	1.4%
Tier 1 Planned Capacity	28	14	-49.1%
Net Firm Capacity Transfers	-1,663	-1,963	18.0%
Anticipated Resources	32,667	32,822	0.5%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	32,667	32,822	0.5%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	55.5%	51.7%	-3.8
Prospective Reserve Margin	55.5%	51.7%	-3.8
Reference Margin Level	12.8%	9.8%	-3.0

The table and chart above provide potential seasonal peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. NPCC-Québec determined the adjustments to peak demand based on methods or assumptions that are summarized below. See the **Data Concepts and Assumptions** for more information about this table and chart.

Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** 90/10 forecast
- **Forced Outages:** Hydro resources operate in extreme conditions without increased outage rates

Highlights

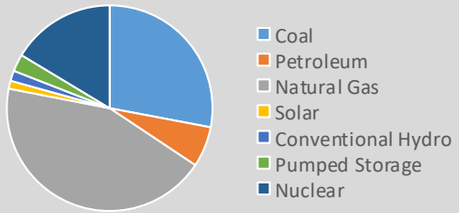
- No resource adequacy or reliability issues are anticipated for the upcoming summer operating period since the Quebec system is winter peaking.
- A strategic 735 kV line was commissioned in May 2019 in order to meet NERC Reliability Standards. The line will provide more flexibility to operators for the upcoming summer period.



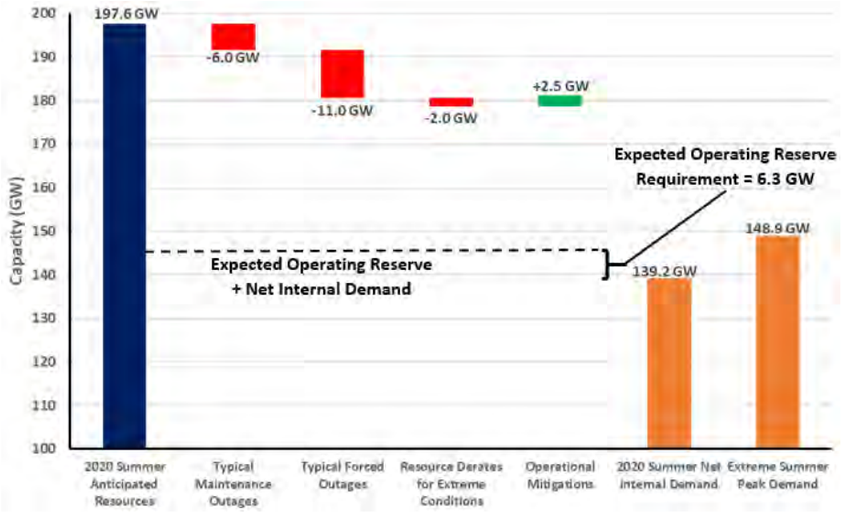
PJM

PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia.

PJM serves 65 million people and covers 369,089 square miles. PJM is a Balancing Authority, Planning Coordinator, Transmission Planner, Resource Planner, Interchange Authority, Transmission Operator, Transmission Service Provider, and Reliability Coordinator.



Seasonal Risk Scenario



PJM Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2019 SRA**	**2020 SRA**	**2019 vs. 2020 SRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	151,358	148,092	-2.2%
Demand Response: Available	8,154	8,929	9.5%
Net Internal Demand	143,204	139,163	-2.8%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	181,013	182,523	0.8%
Tier 1 Planned Capacity	2,200	1,800	-18.2%
Net Firm Capacity Transfers	1,535	1,412	-8.0%
Anticipated Resources	184,748	185,735	7.0%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	184,748	185,735	7.7%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	29.0%	33.5%	4.5
Prospective Reserve Margin	29.0%	33.5%	4.5
Reference Margin Level	15.9%	15.5%	-0.4

The table and chart above provide potential seasonal peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. PJM determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below. See the **Data Concepts and Assumptions** for more information about this table and chart.

Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** 90/10 forecast
- **Outages:** Approximate values based on review of previous summer peak periods

Highlights

- PJM's Anticipated Reserve Margin of 33.5% is well over the reserve margin requirement of 15.5%.
- No known operational challenges are anticipated in PJM for the upcoming summer season.
- PJM's capacity performance initiative has resulted in better generator performance than in years preceding its implementation.



SERC

On July 1, 2019, the integration of FRCC entities into SERC resulted in an additional SERC subregion (SERC FL-Peninsula) for inclusion in NERC's reliability assessments.

SERC is a summer-peaking assessment area that covers approximately 350,000 square miles and serves a population estimated at 69 million. SERC is divided into four assessment areas: SERC- E, SERC-N, SERC-SE, and SERC-FL Peninsula. The SERC assessment area includes 33 Balancing Authorities, 26 Planning Authorities, and 4 Reliability Coordinators.

SERC Resource Adequacy Data							
Demand, Resource, and Reserve Margins	**SERC-C**	**SERC-E**	**SERC-FP**	**SERC-SE**	**2019 SRA SERC Total**	**2020 SRA SERC Total**	**2019 vs. 2020 SRA**
Demand Projections	**Megawatts**	**Megawatts**	**Megawatts**	**Megawatts**	**Megawatts**	**Megawatts**	**Net Change (%)**
Total Internal Demand (50/50)	40,799	43,702	49,286	47,311	179,466	181,098	0.9%
Demand Response: Available	1,970	947	2,906	2,145	8,262	7,968	-3.6%
Net Internal Demand	38,829	42,755	46,380	45,166	171,204	173,130	1.1%
Resource Projections	**Megawatts**	**Megawatts**	**Megawatts**	**Megawatts**	**Megawatts**	**Megawatts**	**Net Change (%)**
Existing-Certain Capacity	48,368	50,825	55,093	61,495	214,712	215,780	0.5%
Tier 1 Planned Capacity	0	88	333	316	2,679	736	-72.5%
Net Firm Capacity Transfers	-807	266	1,146	-972	306	-367	-219.8%
Anticipated Resources	47,561	51,179	56,571	60,839	217,697	216,149	-0.7%
Existing-Other Capacity	4,427	852	529	348	6,034	6,155	2.0%
Prospective Resources	51,988	52,030	57,100	61,186	223,731	222,304	-0.6%
Planning Reserve Margins	**Percent**	**Percent**	**Percent**	**Percent**	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	22.5%	19.7%	22.0%	34.7%	27.2%	24.8%	-2.4
Prospective Reserve Margin	33.9%	21.7%	23.1%	35.5%	30.7%	28.4%	-2.3
Reference Margin Level	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	0.0

Highlights

- To date in the SERC region, there are no significant reliability risks expected for the 2020 summer season.
- All subregions within SERC meet or exceed the reserve margin target of 15%.
- Entities in the SERC region continue to participate actively in the SERC Near-Term and Long-Term Working Groups. These groups identify emerging and potential reliability impacts to transmission and resource adequacy along with transfer capability.

Charts

The charts on the following pages provide potential seasonal peak demand and resource condition information. The table above presents a standard seasonal assessment and comparison to the previous year's assessment. The waterfall charts on the following pages present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. SERC determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below each chart. See the **Data Concepts and Assumptions** for more information about the table and charts.

SERC-C

Seasonal Risk Scenario

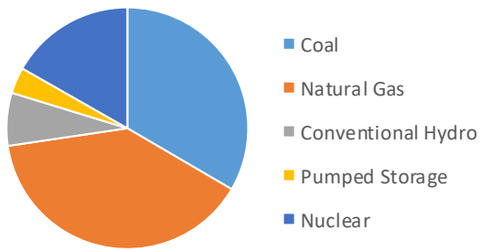


Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** Developed by adjusting subregional peak forecasted load using the probabilistic load multiplier developed in the SERC Probabilistic Assessment
- **Outages:** Based on historical data
- **Extreme Derates:** Determined by entities and aggregated at the subregional level



SERC-E

Seasonal Risk Scenario

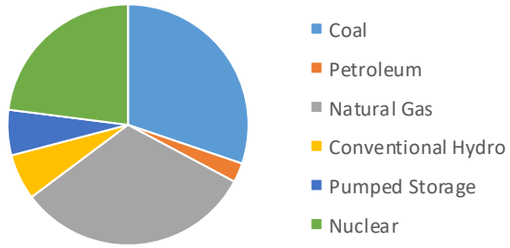


Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

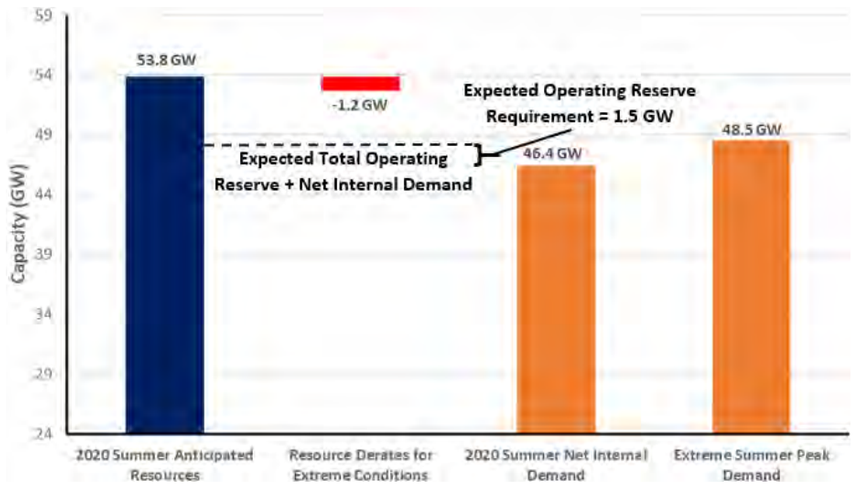
Scenario Assumptions

- **Extreme Peak Load:** Developed by adjusting subregional peak forecasted load using the probabilistic load multiplier developed in the SERC Probabilistic Assessment
- **Outages:** Based on historical data
- **Extreme Derates:** Determined by entities and aggregated at the subregional level



SERC-FP

Seasonal Risk Scenario

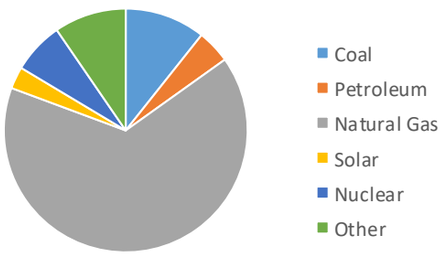


Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

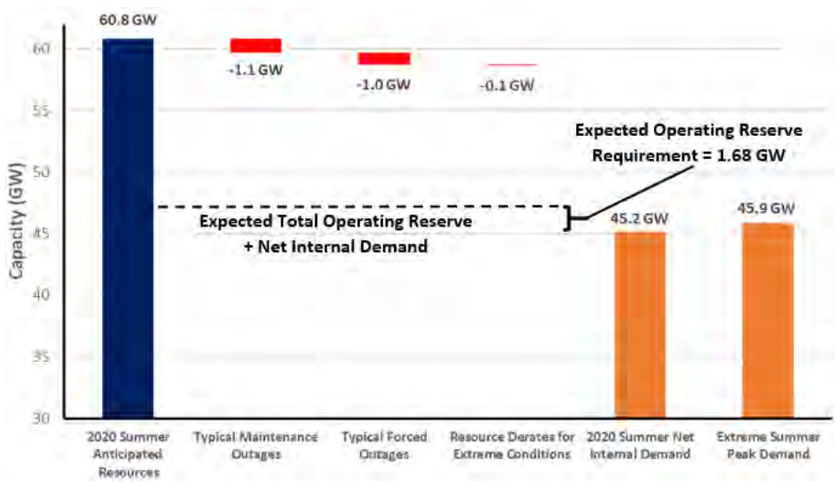
Scenario Assumptions

- **Extreme Peak Load:** Developed by adjusting subregional peak forecasted load using the probabilistic load multiplier developed in the SERC Probabilistic Assessment
- **Outages:** Based on historical data
- **Extreme Derates:** Determined by entities and aggregated at the subregional level



SERC-SE

Seasonal Risk Scenario

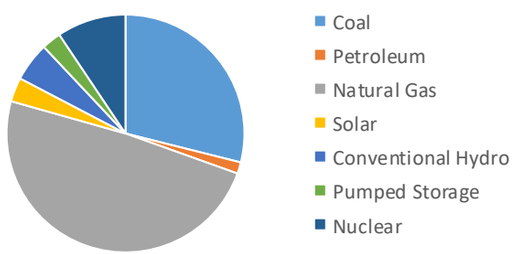


Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** Developed by adjusting subregional peak forecasted load using the probabilistic load multiplier developed in the SERC Probabilistic Assessment
- **Outages:** Based on historical data
- **Extreme Derates:** Determined by entities and aggregated at the subregional level

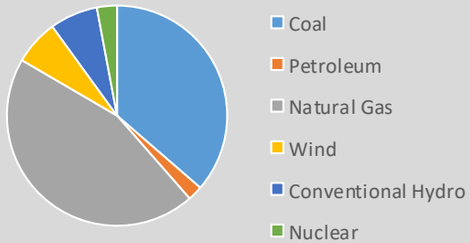




SPP

Southwest Power Pool (SPP) Planning Coordinator footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming.

The SPP long-term assessment is reported based on the Planning Coordinator footprint, which touches parts of the Midwest Reliability Organization Regional Entity, and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million.





SPP Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2019 SRA**	**2020 SRA**	**2019 vs. 2020 SRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	51,520	51,943	0.8%
Demand Response: Available	835	835	0.0%
Net Internal Demand	50,686	51,108	0.8%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	67,960	69,100	1.7%
Tier 1 Planned Capacity	64	0	-100.0%
Net Firm Capacity Transfers	-1,244	-1,244	0.0%
Anticipated Resources	66,780	67,856	1.6%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	66,780	67,856	1.6%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	31.8%	32.8%	1.0
Prospective Reserve Margin	31.8%	32.8%	1.0
Reference Margin Level	12.0%	12.0%	0.0

The table and chart above provide potential seasonal peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. SPP determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below. See the **Data Concepts and Assumptions** for more information about this table and chart.

Risk Scenario Summary

Operating mitigations and EEAs may be needed under extreme demand and extreme resource derated conditions studied.

Scenario Assumptions

- **Extreme Peak Load:** 90/10 Forecast
- **Outages:** A capacity derate for maintenance outages, forced outages, and performance in extreme weather based on historical data

Highlights

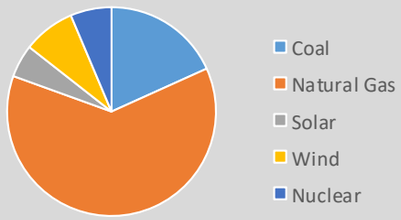
- SPP does not anticipate any emerging reliability issues impacting the area for the 2020 summer season.
- In an effort to minimize declared periods of conservative operations and EEAs that may arise from uncertainty in wind forecasts, SPP created new mitigation processes to deal with high impact areas of concern. SPP has developed operational mitigation teams as well as processes and procedures to maintain real time reliability needs; some of these are new and will be relied upon for the first time in the 2020 summer season.



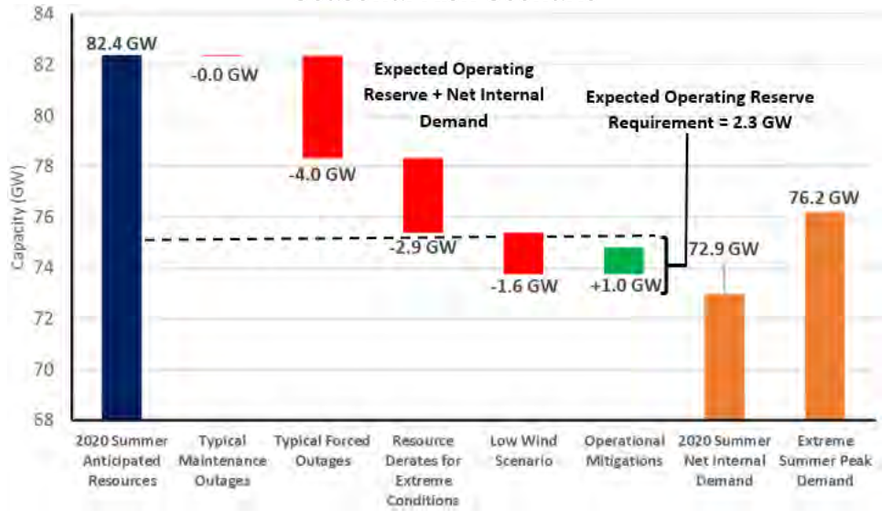
Texas RE-ERCOT

The Electric Reliability Council of Texas (ERCOT) is the ISO for the ERCOT Interconnection and is located entirely in the state of Texas; it operatesas a single Balancing Authority. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature.

ERCOT is a summer-peaking Region that covers approximately 200,000 square miles, connects over 46,500 miles of transmission lines, has over 680 generation units, and serves more than 26 million customers. Texas RE is responsible for the regional RE functions described in the *Energy Policy Act of 2005* for the ERCOT Region.



Seasonal Risk Scenario



Texas RE-ERCOT Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2019 SRA**	**2020 SRA**	**2019 vs. 2020 SRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	74,853	75,200	0.5%
Demand Response: Available	2,227	2,251	1.1%
Net Internal Demand	72,626	72,949	0.4%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	77,482	79,395	2.5%
Tier 1 Planned Capacity	607	2,172	257.9%
Net Firm Capacity Transfers	721	817	13.3%
Anticipated Resources	78,810	82,384	4.5%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	78,810	82,412	4.6%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	8.5%	12.9%	4.4
Prospective Reserve Margin	8.5%	13.0%	4.5
Reference Margin Level	13.75%	13.75%	0.0

The table and chart above provide potential seasonal peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. ERCOT determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below.

Risk Scenario Summary

Operating mitigations and EEAs may be needed to meet extreme demand or extreme resource derated conditions.

Scenario Assumptions

- **Extreme Peak Load:** Based on 2011 historic summer peak load
- **Outages:** A derate for maintenance and forced outages based on the past three summer periods
- **Extreme Derates:** Based on 95th percentile of historical forced outages for June – September, hours ending 2:00 p.m.–8:00 p.m. for the last three summer seasons
- **Operational Mitigations:** Additional resources (e.g., switchable generation resources, additional imports, and voltage reduction) to support maintaining operating reserves, not already counted in SRA reserve margins

Highlights

- ERCOT's anticipated reserve margin, 12.9%, is higher than last summer due mainly to greater planned wind and solar capacity. Increases are attributed to completion of new projects as well as delayed projects from 2019 and improved methods for calculating wind and solar capacity contributions.
- The Planning Reserve Margin is considered tight. ERCOT expects grid operations to be similar to last summer, assuming that peak loads hit record levels as forecasted.
- ERCOT assumes the availability of 817 MW of dc tie net imports from SPP during its forecasted summer peak load hours based on recent historical experience and expected energy market conditions for the upcoming summer. Emergency conditions in both areas simultaneously would impact imports into ERCOT. ERCOT does not expect COVID-19-related delays for planned projects with expected in-service dates prior to the summer season.
- There are no known transmission reliability, fuel supply, or essential reliability service procurement issues projected for summer. Continued penetration of wind and solar resources is expected to further stress system conditions and call for additional actions to maintain system stability. Stability constraints are managed through generic transmission constraints (GTCs) in real-time operations. ERCOT assesses the impact of future planned new generation to determine the adequacy of existing GTCs and the need for developing new GTCs or system improvements.



WECC

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members, which include 38 Balancing Authorities, represent a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million people, it is geographically the largest and most diverse of the NERC Regional Entities. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 western states of the United States in between. The WECC assessment area is divided into six subregions: Rocky Mountain Reserve Group (RMRG), Southwest Reserve Sharing Group (SRSG), California/Mexico (CA/MX), the Northwest Power Pool (NWPP), and the Canadian areas of Alberta (WECC AB), and British Columbia (WECC BC). These subregional divisions are used for this study as they are structured around reserve sharing groups that have similar annual demand patterns and similar operating practices.

WECC Resource Adequacy Data

Demand, Resource, and Reserve Margins	WECC AB	WECC BC	CA/MX	NWPP-US	RMRG	SRSG	2019	2020	2019 vs. 2020 SRA
Demand Projections	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**Total MW**	**Total MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,500	8,278	53,236	53,964	12,568	25,145	156,142	164,691	5.5%
Demand Response: Available	0	0	910	629	240	144	2,164	1,923	-11.1%
Net Internal Demand	11,500	8,278	52,326	53,335	12,328	25,001	153,979	162,768	5.7%
Resource Projections	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	14,356	11,471	63,186	62,770	16,068	29,440	194,208	197,292	1.6%
Tier 1 Planned Capacity	0	215	92	817	53	477	3961	1,653	-58.3%
Net Firm Capacity Transfers	0	0	0	749	0	0	0	749	0.0%
Anticipated Resources	14,356	11,686	63,278	64,336	16,122	29,917	198,169	199,694	0.8%
Existing-Other Capacity	0	0	0	0	0	0	0	0	0.0%
Prospective Resources	14,356	11,686	63,278	64,336	16,122	29,917	198,169	199,694	0.8%
Planning Reserve Margins	**Percent**	**Percent**	**Percent**	**Percent**	**Percent**	**Percent**	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	24.8%	41.2%	20.9%	20.6%	30.8%	19.7%	28.7%	22.7%	-6.0
Prospective Reserve Margin	24.8%	41.2%	20.9%	20.6%	30.8%	19.7%	28.7%	22.7%	-6.0
Reference Margin Level	10.4%	10.4%	13.7%	15.7%	13.0%	10.0%	15.4%	15.4%	0.0

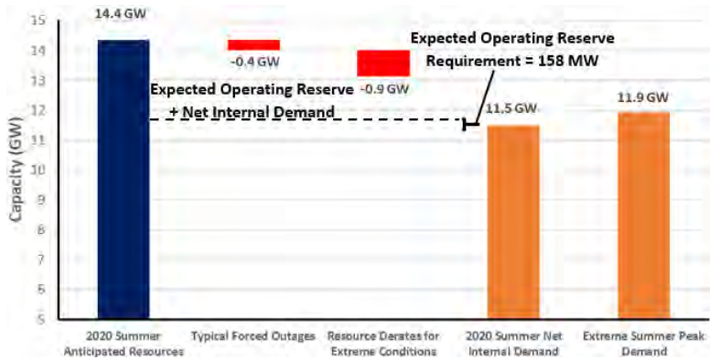
Highlights

- The existing and Anticipated Reserve Margins for WECC, its subregions, and all zones within are expected to exceed their respective NERC Reference Margin Levels for the upcoming season.
- Below-normal hydro conditions are present in California that could reduce energy available from hydro resources throughout the summer. Hydro resources and imports from neighboring areas are important for maintaining system reliability in the California ISO area, where dispatchable generation has declined and variable generation is increasing. Extreme heat extending over California and neighboring areas could pose operating risk if surplus energy for import is reduced. Risks are heightened later in the summer when energy from hydro resources will be lower and solar PV output is near zero at the peak hour.
- Inventories of the Aliso Canyon Natural Gas Storage Facility (Aliso Canyon) remain an item of focus for electric reliability within the Western Interconnection. Going into the 2020 summer, the Southern California Gas Company (SoCalGas) system has more natural gas in storage and additional transmission lines in service, making it better postured to support natural gas users including electricity generators. SoCalGas estimates that it will be able to meet the forecasted peak day demand under a "best case" supply assumption even without supply from Aliso Canyon. Under a "worst case" supply assumption, the forecasted peak day demand cannot be met without curtailment even with the use of supply from Aliso Canyon.

The charts on the next page provide potential peak demand and resource condition information. The table above presents a standard seasonal assessment and comparison to the previous year's assessment. The waterfall charts on the next page present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. WECC entities determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized on the next page. See the **Data Concepts and Assumptions** for more information about the table and charts.

WECC-Alberta

Seasonal Risk Scenario

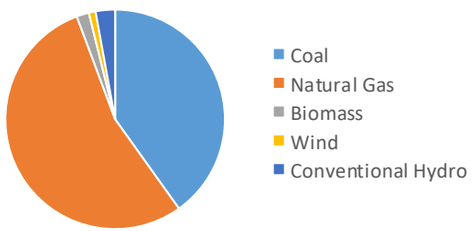


Risk Scenario Summary

Operating mitigations and EEAs may be needed under extreme demand and extreme resource derated conditions studied.

Scenario Assumptions

- **Extreme Peak Load:** Based on 90/10 demand forecast
- **Forced Outages:** Based on historical data
- **Extreme Derates:** Developed using the 10th percentile availability curves for the thermal, wind, and solar resources at the assessment area peak hour



WECC-British Columbia

Seasonal Risk Scenario

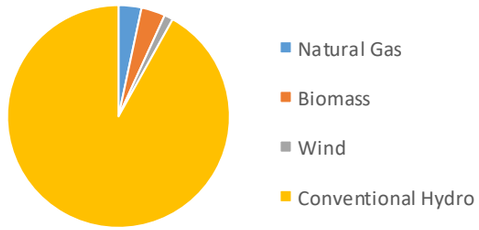


Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

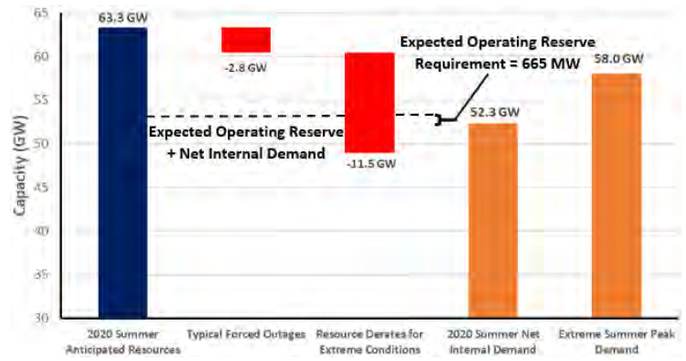
Scenario Assumptions

- **Extreme Peak Load:** Based on 90/10 demand forecast
- **Forced Outages:** Based on historical data
- **Extreme Derates:** Developed using the 10th percentile availability curves for the thermal, wind, and solar resources at the assessment area peak hour



WECC-California / Mexico

Seasonal Risk Scenario

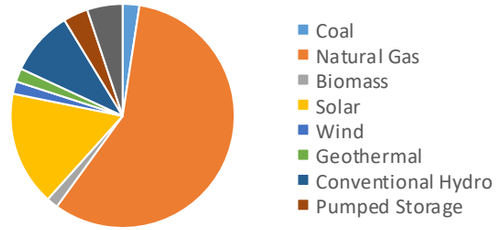


Risk Scenario Summary

Operating mitigations and EEAs may be needed under extreme demand and extreme resource derated conditions.

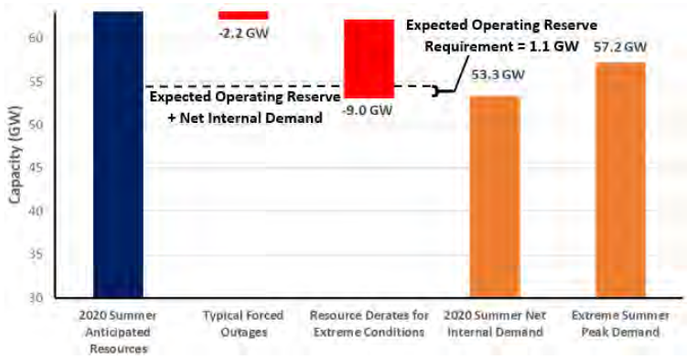
Scenario Assumptions

- **Extreme Peak Load:** Based on 90/10 demand forecast
- **Forced Outages:** Based on historical data
- **Extreme Derates:** Developed using the 10th percentile availability curves for the thermal, wind, and solar resources at the assessment area peak hour



WECC-Northwest Power Pool

Seasonal Risk Scenario

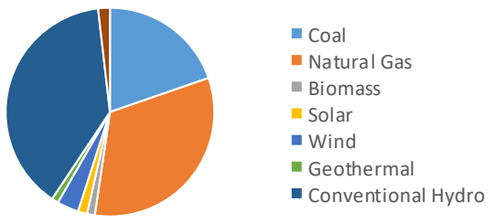


Risk Scenario Summary

Resources meet operating reserve requirements for normal peak-load and outage conditions. Operating mitigations and EEAs may be needed under extreme resource derated conditions.

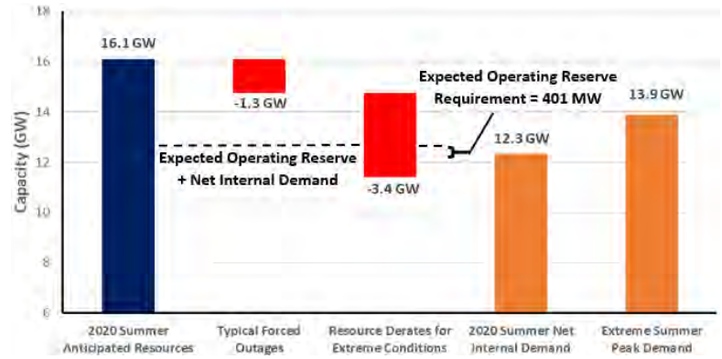
Scenario Assumptions

- **Extreme Peak Load:** Based on 90/10 demand forecast
- **Forced Outages:** Based on historical data
- **Extreme Derates:** Developed using the 10th percentile availability curves for the thermal, wind, and solar resources at the assessment area peak hour



WECC-Rocky Mountain Reserve Sharing Group

Seasonal Risk Scenario

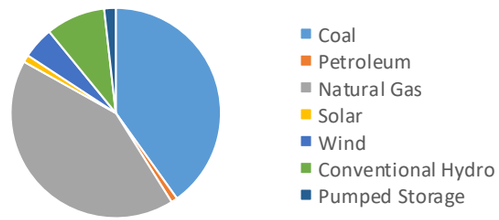


Risk Scenario Summary

Resources meet operating reserve requirements for normal peak-load and outage conditions. Operating mitigations and EEAs may be needed under extreme resource derated conditions.

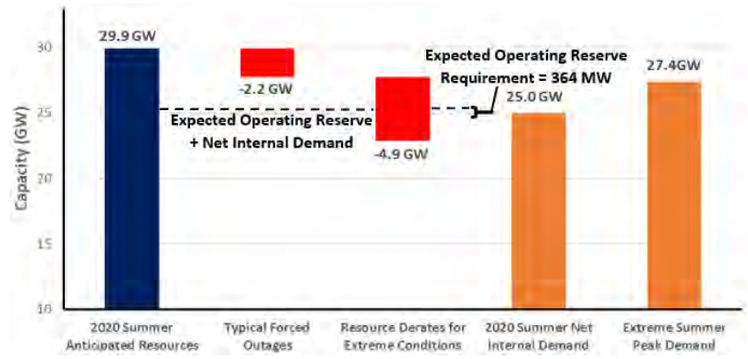
Scenario Assumptions

- **Extreme Peak Load:** Based on 90/10 demand forecast
- **Forced Outages:** Based on historical data
- **Extreme Derates:** Developed using the 10th percentile availability curves for the thermal, wind, and solar resources at the assessment area peak hour



WECC-Southwest Reserve Sharing Group

Seasonal Risk Scenario

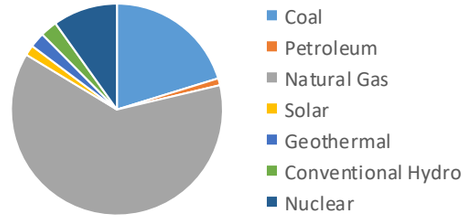


Risk Scenario Summary

Resources meet operating reserve requirements for normal peak-load and outage conditions. Operating mitigations and EEAs may be needed under extreme resource derated conditions.

Scenario Assumptions

- **Extreme Peak Load:** Based on 90/10 demand forecast
- **Forced Outages:** Based on historical data
- **Extreme Derates:** Developed using the 10th percentile availability curves for the thermal, wind, and solar resources at the assessment area peak hour



Data Concepts and Assumptions

The table below explains data concepts and important assumptions used throughout this assessment.

General Assumptions
• Reliability of the interconnected BPS is comprised of both adequacy and operating reliability: ▪ Adequacy is the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components. ▪ Operating reliability is the ability of the electric system to withstand sudden disturbances such as electric short-circuits or unanticipated loss of system components.
• The reserve margin calculation is an important industry planning metric used to examine future resource adequacy.
• All data in this assessment is based on existing federal, state, and provincial laws and regulations.
• Differences in data collection periods for each assessment area should be considered when comparing demand and capacity data between year-to-year seasonal assessments.
• *2019 Long-Term Reliability Assessment* data has been used for most of this 2020 assessment period augmented by updated load and capacity data.
• A positive net transfer capability would indicate a net importing assessment area; a negative value would indicate a net exporter.
Demand Assumptions
• Electricity demand projections, or load forecasts, are provided by each assessment area.
• Load forecasts include peak hourly load[11] or total internal demand for the summer and winter of each year.[12]
• Total internal demand projections are based on normal weather (50/50 distribution[13]) and are provided on a coincident[14] basis for most assessment areas.
• Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour.
Resource Assumptions
Resource planning methods vary throughout the North American BPS. NERC uses the categories below to provide a consistent approach for collecting and presenting resource adequacy. **Table 2** below shows the wind and solar generation resources in each assessment area and describes how capacity contributions values are determined.
Anticipated Resources: • **Existing-Certain Capacity**: Included in this category are commercially operable generating unit or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the summer season: unit must have a firm capability and have a power purchase agreement (PPA) with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or where energy-only markets exist, unit must be a designated market resource eligible to bid into the market. • **Tier 1 Capacity Additions**: This category includes capacity that either is under construction or has received approved planning requirements. • **Net Firm Capacity Transfers (Imports minus Exports)**: This category includes transfers with firm contracts.
Prospective Resources: Includes all anticipated resources plus the following: **Existing-Other Capacity**: Included in this category are commercially operable generating units or portions of generating units that could be available to serve load for the period of peak demand for the season but do not meet the requirements of existing-certain.
Reserve Margin Descriptions
Planning Reserve Margin: This is the primary metric used to measure resource adequacy; it is defined as the difference in resources (anticipated or prospective) and net internal demand then divided by net internal demand and shown as a percentage.

[11] *Glossary of Terms* used in NERC Reliability Standards

[12] The summer season represents June–September and the winter season represents December–February.

[13] Essentially, this means that there is a 50% probability that actual demand will be higher and a 50% probability that actual demand will be lower than the value provided for a given season/year.

[14] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval; this is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year. SERC and FRCC calculate total internal demand on a noncoincidental basis.

Reference Margin Level: The assumptions and naming convention of this metric vary by assessment area. The Reference Margin Level can be determined using both deterministic and probabilistic (based on a 0.1/year loss of load study) approaches. In both cases, this metric is used by system planners to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing a Reference Margin Level is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increase demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, a Reference Margin Level is established by a state, provincial authority, ISO/RTO, or other regulatory body. In some cases, the Reference Margin Level is a requirement. Reference Margin Levels may be different for the summer and winter seasons. If a Reference Margin Level is not provided by an assessment area, NERC applies 15% for predominately thermal systems and 10% for predominately hydro systems.

Seasonal Risk Scenario Chart Description

Each assessment area performed an operational risk analysis that was used to produce the seasonal risk scenario charts in the **Regional Assessment Dashboards**. The chart presents deterministic scenarios for further analysis of different resource and demand levels: The left blue column shows anticipated resources (from the resource adequacy data table), and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand from the resource adequacy data table and the extreme summer peak demand—both determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources, such as the following:

- Reductions for typical generation outages (i.e., maintenance and forced, not already accounted for in anticipated resources)
- Reductions that represent additional outage or performance derating by resource type for extreme, low-probability conditions (e.g., drought condition impacts on hydroelectric generation, low-wind scenario affecting wind generation, fuel supply limitations, or extreme temperature conditions that result in reduced thermal generation output)
- Additional capacity resources that represent quantified capacity from operational procedures, if any, that are made available during scarcity conditions

Not all assessment areas have the same categories of adjustments to anticipated resources. Furthermore, each assessment area determined the adjustments to capacity based on methods or assumptions that are summarized below the chart. Methods and assumptions differ by assessment area and may not be comparable.

The chart enables evaluation of resource levels against levels of expected operating reserve requirement and the forecasted demand. Further, the effects from low-probability, extreme events can also be examined by comparing resource levels after applying extreme-scenario derates and/or extreme summer peak demand. Because such extreme scenario analysis depicts the cumulative impact resulting from the occurrence of multiple low-probability events, the overall likelihood of this scenario is very low.

BPS Wind and Solar Generation Resources by Assessment Area

Assessment Area	Wind			Solar		
	Nameplate (MW)	Available Peak Demand Hour Capacity (MW)	Available/Nameplate (%)	Nameplate (MW)	Available Peak Demand Hour Capacity (MW)	Available/Nameplate (%)
MISO	21,594	4,417	20.5%	663	390	58.8%
MRO-Manitoba Hydro	259	44	17.0%	0	0	-
MRO-SaskPower	241	55.8	23.2%	29	0	0.0%
NPCC-Maritimes	1,170	283	24.2%	2	0	0.0%
NPCC-New England	1,421	178	12.5%	200	119	59.5%
NPCC-New York	1,985	301	15.2%	57	16	27.7%
NPCC-Ontario	4,846	664	13.7%	478	66	13.8%

BPS Wind and Solar Generation Resources by Assessment Area						
Assessment Area	Wind			Solar		
	Nameplate (MW)	Available Peak Demand Hour Capacity (MW)	Available/Nameplate (%)	Nameplate (MW)	Available Peak Demand Hour Capacity (MW)	Available/Nameplate (%)
NPCC-Quebec	3,904	0	0.0%	0	0	-
PJM	10,399	1,648	15.8%	4,684	2,415	51.6%
SERC-C	480	456	95.0%	10	8	80.0%
SERC-E	0	0	-	555	546	98.4%
SERC-FP	0	0	-	2,969.3	1,582.3	-
SERC-SE	0	0	-	2,266	2,259	99.7%
SPP	23,529	5,761	24.5%	272	201	73.9%
Texas RE-ERCOT	27,847	6,924	24.9%	3,735	2,838	76.0%
WECC-AB	1,445	142	9.8%	115	4.5	3.9%
WECC-BC	727.5	146	20.1%	2	0.6	30.0%
WECC-CAMX	6,773	1,097	16.2%	13,774	10,090	73.3%
WECC-NWPP-US	10,898	2,023	18.6%	5,831	883	15.1%
WECC-RMRG	3,852	774	20.1%	756	180	23.8%
WECC-SRSG	1,327	203	15.3%	1,698	458	27.0%

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2021 Summer Reliability Assessment

May 2021



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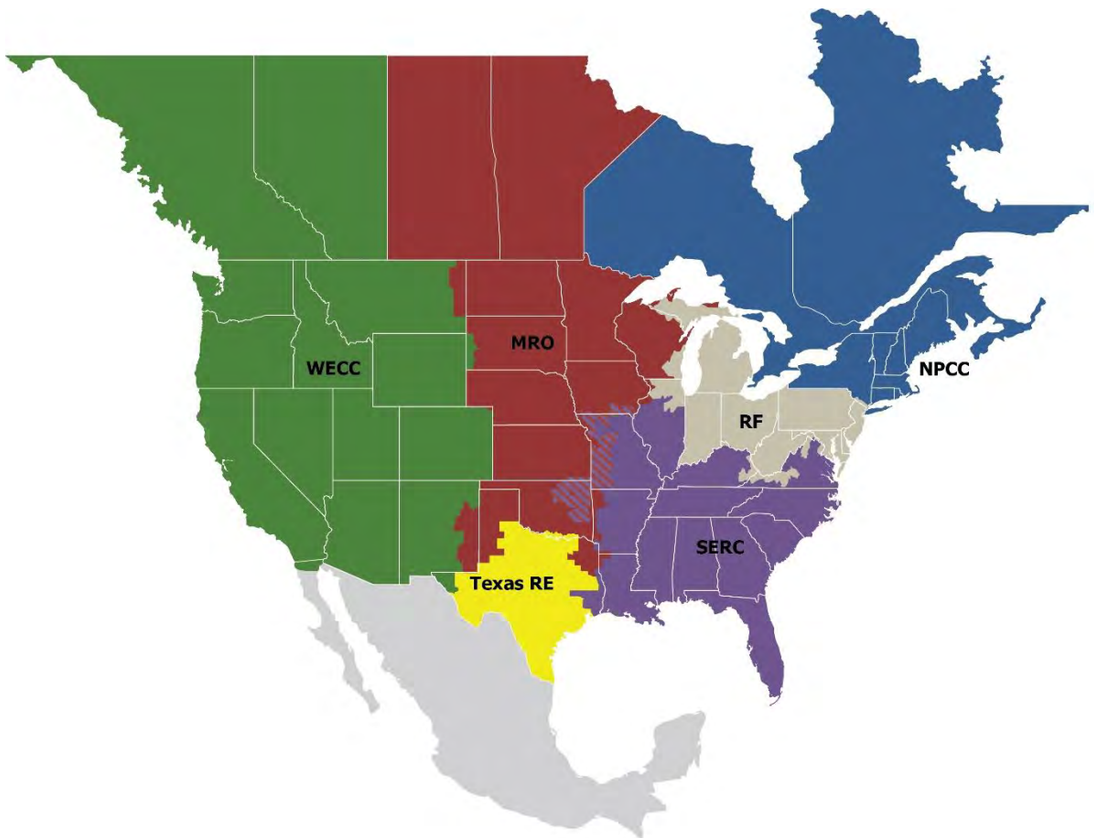
Preface

The vision for the Electric Reliability Organization Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (RE), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six RE boundaries as shown in the map below. The multicolored area denotes overlap as some load-serving entities participate in one RE while associated Transmission Owners/Operators participate in another. Refer to the **Data Concepts and Assumptions** section for more information. A map and list of the assessment areas can be found in the **Regional Assessments Dashboards** section.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

About this Report

NERC's *2021 Summer Reliability Assessment* (SRA) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming summer season. In addition, the SRA presents peak electricity demand and supply changes and highlights any unique regional challenges or expected conditions that might impact the BPS. The reliability assessment process is a coordinated reliability evaluation between the Reliability Assessment Subcommittee (RAS), the RE, and NERC staff. This report reflects NERC's independent assessment and is intended to inform industry leaders, planners, operators, and regulatory bodies so that they are better prepared to take necessary actions to ensure BPS reliability. This report also provides an opportunity for the industry to discuss plans and preparations to ensure reliability for the upcoming summer period.

Findings

NERC's annual SRA covers Summer 2021 (June–September). This assessment provides an evaluation of the resource and transmission system adequacy that is necessary to meet projected summer peak demands. In addition to assessing resource adequacy, the SRA monitors and identifies potential reliability issues of interest and regional topics of concern. The following key findings represent NERC's independent evaluation of electric generation and transmission capacity as well as potential operational concerns that may need to be addressed for the upcoming summer:

- Parts of North America are at elevated risk to energy emergencies (see **Figure 1**). Above-normal heat in summer can challenge grid operators by increasing demand from temperature-dependent loads (such as air-conditioning and refrigeration) and reducing electricity supplies as a result of lower-than-capacity resource output or increased outages. Wide-area heat events (such as the August 2020 heat wave that affected much of the Western United States and Mexico) are especially challenging as fewer resources are available for electricity transfers between areas because they are required to serve native load:
  - In **Texas RE**, on-peak Planning Reserve Margins have increased to 15.3% from 12.9% last summer with the addition of 7,858 MW wind, solar, and battery resources since 2020. However, extreme weather can affect both generation and demand and cause energy shortages that lead to energy emergencies in the Electric Reliability Council of Texas (ERCOT). Furthermore, with a significant portion of electricity supply coming from wind generation, operators must have sufficient flexible resources to cover periods of low-wind output.
  - Across most of **WECC**, resource and energy adequacy is a significant concern for the summer with overall capacity and demand projections for the area at similar levels to those seen in 2020 when a wide-area heat event caused energy emergencies and managed firm load loss. Though new flexible resources have been added in California, peak demand projections have also increased in many parts of the west, and overall resource capacity is lower compared to 2020. Increasing demand and lower resource capacity across WECC can mean the availability of surplus capacity for transfer into stressed areas is declining.
  - **MISO** and **NPCC-New England** have sufficient resources for periods of peak demand. However, the above-normal levels of demand in the 90/10 forecast are likely to exceed capacity resources and require additional non-firm transfers from surrounding areas.
  - All other areas have sufficient resources to manage normal summer peak demand and are at low risk of energy shortfalls from more extreme demand or generation outage conditions. Anticipated Reserve Margins meet or surpass the Reference Margin Level, indicating that planned resources in these areas are adequate to manage the risk of a capacity deficiency under normal conditions.[1] Furthermore, based on risk scenario analysis in these areas, resources and energy appear adequate.

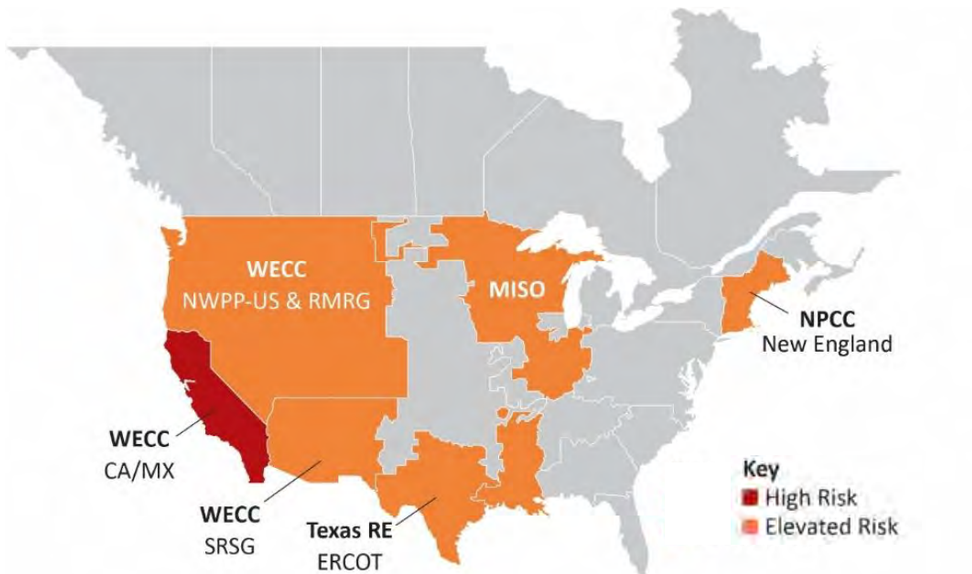


Figure 1: Energy Emergency Risk Areas

- **WECC-California is at risk of energy emergencies during periods of normal peak summer demand and high risk when above-normal demand is widespread in the west.** Prior to summer, the planning reserve margin (which is based on existing and firm capacity) for the California-Mexico assessment area was below the 18.4% Reference Margin Level that WECC calculates is

[1] For more information, see the description of the "Reference Margin Level" in the **Data Concepts and Assumptions** section of this report or refer to NERC's *Long-term Reliability Assessment*: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2020.pdf

needed for maintaining loss-of-load risk below a 1-day-in-10-year benchmark (a 400 MW shortfall at peak demand). Probabilistic studies indicate 10,185 MWh of energy in the area is expected to go unserved this summer. Over 3 GW of additional resources are expected for this summer with most coming in the form of new solar photovoltaic (PV) generation. These generation plants can provide energy to support peak demand; however, solar PV output falls off rapidly in late afternoon while high demand often remains.

Imports to the area are needed to maintain reliability when demand peaks in the afternoon and to ramp up even further for several hours as internal resources draw down. California will have 675 MW of new battery energy storage systems on-line at the start of the summer that can continue to supply stored energy for periods when needed. Reliance on non-firm imports to cover high demand or low resource output conditions heightens the risk that operators will need to use energy emergency alerts (EEA)—and trigger the shedding of firm load in above-normal heat conditions—to maintain a stable BPS at times. Planned resource additions of 1,300 MW over the summer, including 825 MW of new battery storage, are expected to help mitigate late-summer risks.

- **Protecting the critical electrical workforce from health risks during pandemic remains a priority.** Protocols put in place for reducing risks to personnel in control centers and on the front lines, including mutual assistance in hurricane-damaged areas, should be maintained as warranted by public health conditions. Also related to the coronavirus (COVID-19) pandemic, operators must continue to give attention to daily load shapes that can be sensitive to changing behaviors of the workforce and commercial loads. In 2021, there is remaining uncertainty in demand projections as governments adjust to changing public health guidelines and conditions and as the behavior of society adapts.
- **The Late-summer wildfire season in Western United States and Canada poses risk to BPS reliability.** Government agencies warn of the potential for above-normal wildfire risk beginning in July in parts of the Western United States as well as Central and Western Canada.[2,3] Operation of the BPS can be impacted in areas where wildfires are active as well as areas where there is heightened risk of wildfire ignition due to weather and ground conditions (see **Figure 3**).

Implications and Recommendations

The summer of 2021 is shaping up to be a challenge for electric system operators in many parts of North America, combining the resource situation described above with significant drought, fire, and high temperature risk assessments by independent agencies. In the near term, NERC recommends the following:

- Load-serving entities (LSE) and regulators work with their Balancing Authorities (BA) and Reliability Coordinators (RC) to ensure that clear lines of communication are open for coordination during periods of system stress. RC, BA, and Transmission Operators review outage schedules well in advance and coordinate across the RC area.
- BA and RC conduct drills on their alert programs to ensure that they are prepared to signal need for conservative operations, restrictive maintenance periods, etc. BA and Generator Operators verify protocols and operator training for communication and dispatch.
- LSE prepare for demand-side conservation measures and potentially condition customers to their need and efficacy.
- RC and BA maintain the highest vigilance during peak risk hours and forecasted high temperature periods.
- LSE review non-firm customer inventories and rolling black out procedures to ensure that no critical infrastructure loads (e.g., natural gas, telecommunications, etc.) would be affected.

Finally, the potential for these conditions to emerge were reflected in NERC's *2018* and *2020 Long-Term Reliability Assessments*; we recommend policy makers, system planners, LSE, and Generator Owners review these assessments and factor them into their integrated resource plans, and ISO/RTO factor them into their own generation queue management and long-range planning processes.[4]

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[2] See North American Seasonal Fire Assessment and Outlook, April 2021: https://www.predictiveservices.nifc.gov/outlooks/NA_Outlook.pdf.
[3] See Natural Resources Canada seasonal wildland fire forecasts: https://cwfis.cfs.nrcan.gc.ca/maps/forecasts
[4] NERC's Reliability Assessments web page: https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx

Summer Temperature and Drought Forecasts

Peak electricity demand in most areas is strongly influenced by temperature. Weather officials are expecting above normal temperatures for much of North America this summer (see **Figure 2**). Assessment area load forecasts account for many years of historical demand data, often up to 30 years, to predict summer peak demand and prepare for more extreme conditions. Above average seasonal temperatures can contribute to high peak demand as well as increases in forced outages for generation and some BPS equipment. Effective preseason maintenance and preparations are particularly important to BPS reliability in severe or prolonged periods of above-normal temperatures.

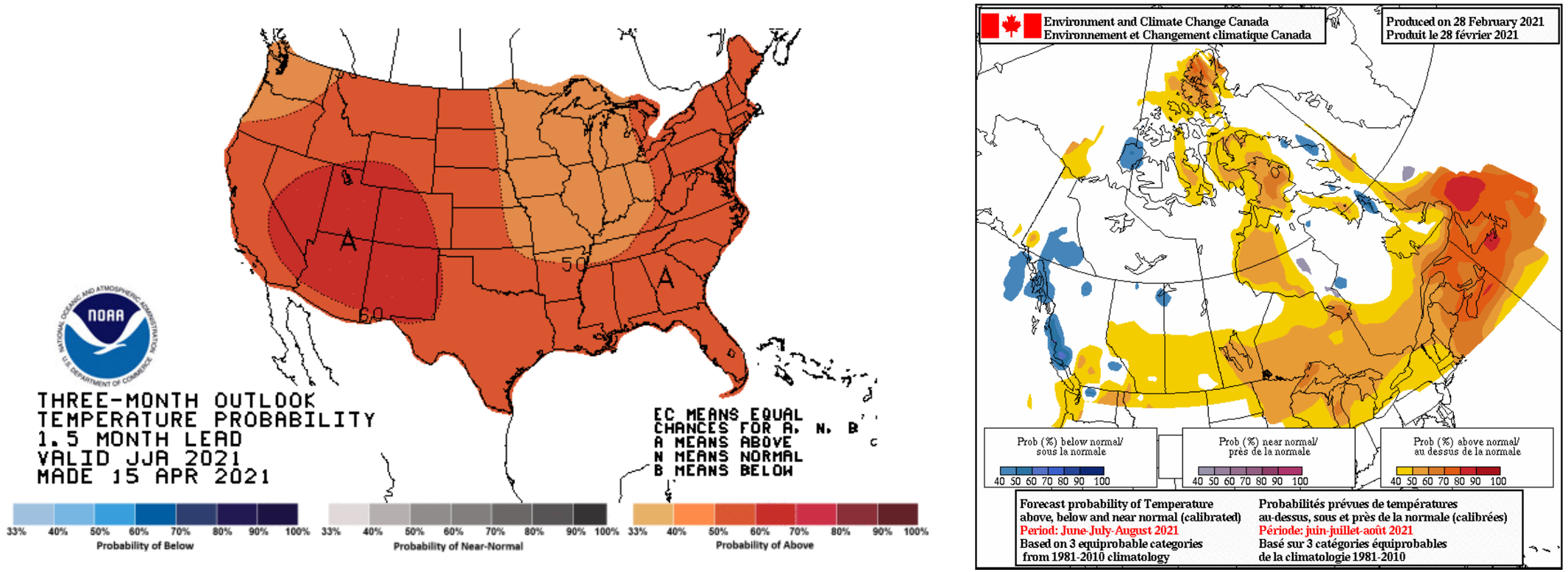


Figure 2: United States and Canada Summer Temperature Outlook[5]

[5] Seasonal forecasts obtained from U.S. National Weather Service and Natural Resources Canada: https://www.cpc.ncep.noaa.gov/products/predictions/long_range/ and https://weather.gc.ca/saisons/prob_e.html

Wildfire Risk Potential and BPS Impacts

Drought conditions extend over the western half of the United States and the middle-third of Canada. Above-normal fire risk at the beginning of the summer exists in the Southwest United States and over the middle-third of North America in the spring, setting the stage for an active fire season at the beginning of the summer (see **Figure 3**). Government agencies predict an active early fire season in the Southwest United States as well as above-normal risk in the lower half of central Canada (Southern Prairies, Boreal forest, grassland and parkland areas).[6] In late summer, hotter and drier conditions are expected to cause elevated fire risk in California and the United States West Coast. BPS operation can be impacted in areas where wildfires are active as well as areas where there is heightened risk of wildfire ignition due to weather and ground conditions (see **Finding: Risk Discussion**).

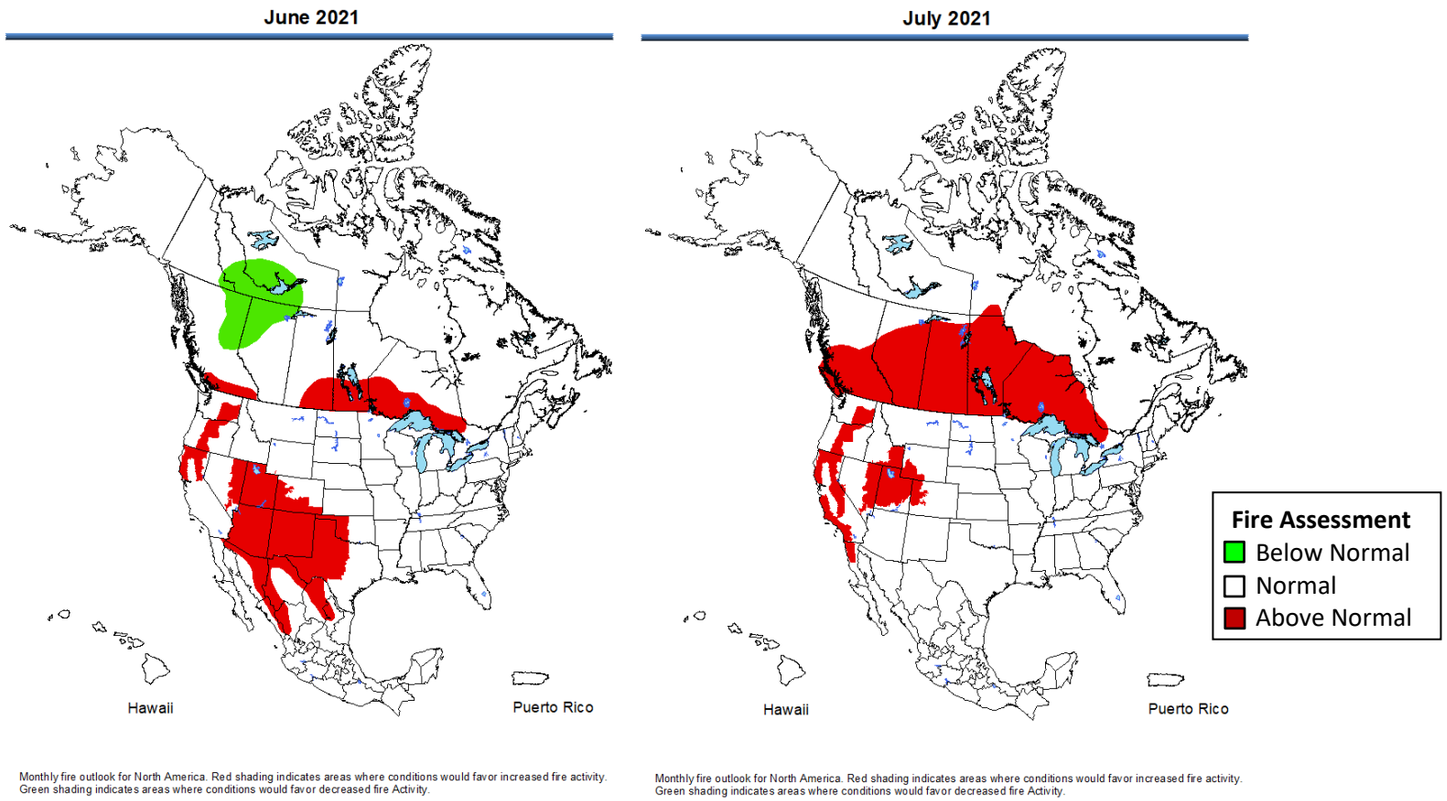


Figure 3: North American Seasonal Fire Assessment for June and July 2021

[6] See North American Seasonal Fire Assessment and Outlook, April 2021: https://www.predictiveservices.nifc.gov/outlooks/NA_Outlook.pdf

Finding: Risk Discussion

Texas RE: ERCOT Interconnection

With forecasted growth in peak demand and new generation resources primarily coming in the form of variable wind and solar generation, the risk of shortages that lead to energy emergencies in ERCOT continues for the upcoming summer. On-peak Planning Reserve Margins have increased to 15.3% from 12.9% last summer with the addition of 7,858 MW wind, solar, and battery resources since 2020; This exceeds the 13.75% Reference Margin Level established in ERCOT for reliably serving demand under normal summer peak conditions. However, extreme weather can affect both resource and demand and cause energy shortages that lead to energy emergencies in ERCOT. Furthermore, with a significant portion of electricity supply coming from wind generation, operators must have sufficient flexible resources to cover periods of low-wind output (see **Figure 4** for a risk scenario involving 90/10 low wind conditions and normal 50/50 peak demand). Operational mitigations may be needed in unexpected wind generation shortfalls to avoid energy emergencies.

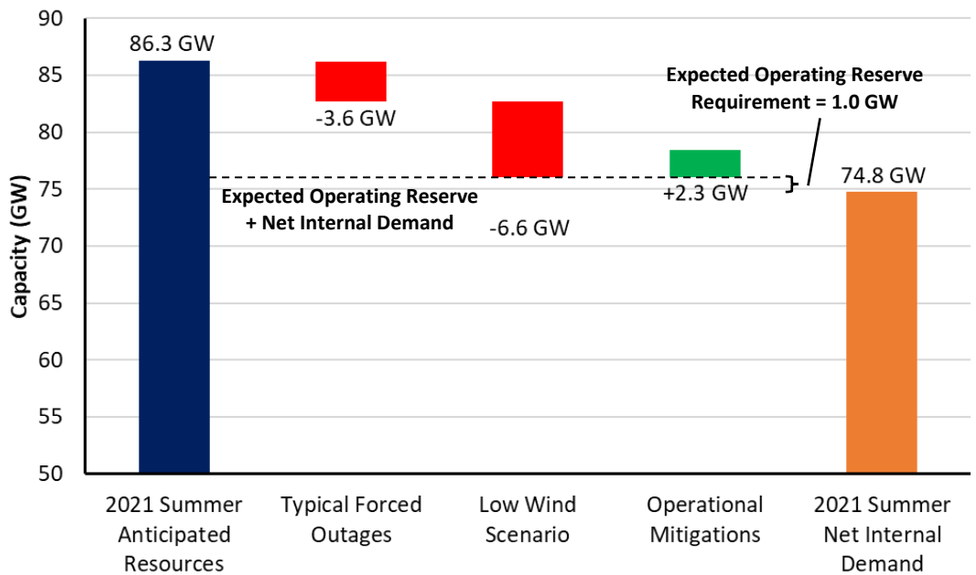


Figure 4: Combination of Low-Wind and Normal Generator Outages at Peak Demand in ERCOT

Weather conditions can create an elevated risk of operating emergencies in ERCOT in the event that higher demand or lower resource output diminishes the relatively low reserve margins that exist on the system. Shown in **Figure 5** are the 1-in-10 year high demand levels alongside an extreme low-resource scenario: 12.1% of expected thermal resources are unavailable as well as 76.8% reduced output of expected wind (this is 6.2% of the total installed nameplate wind capacity operating). Combinations of high peak demand and extreme low resource output are exceedingly rare; however, they are plausible and provide industry and stakeholders with insights into potential emergency conditions. The result of the described scenario is a 12.7 GW shortfall. In challenging conditions like those depicted, operators would resort to implementing rotating outages as a measure of preserving the BPS.

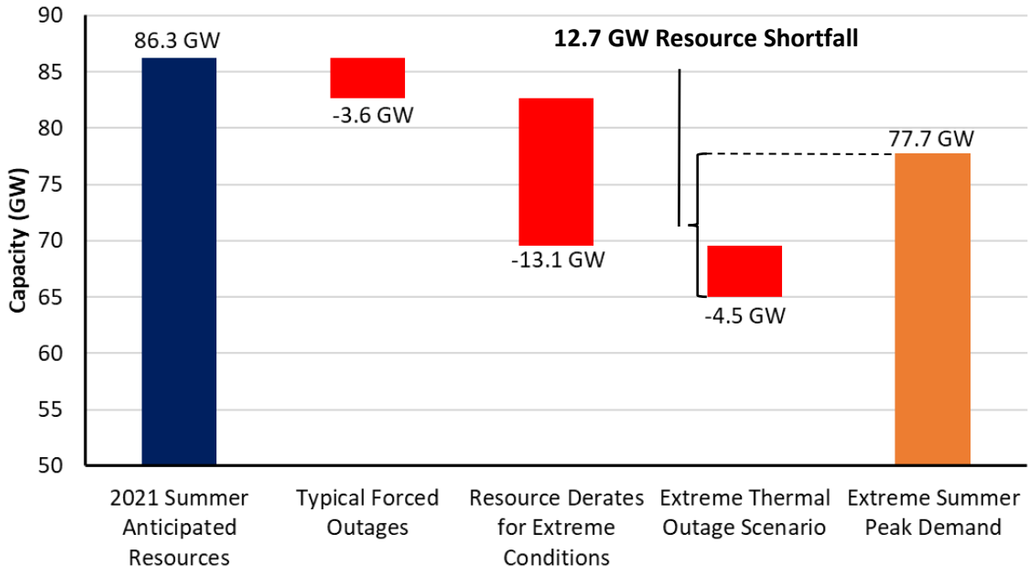


Figure 5: Impact of Extreme Demand and Resource Outages in ERCOT

In addition to the 1-in-10 year demand scenario above, ERCOT conducted an additional extreme demand scenario based on a wide-area heat event. In this scenario, peak demand increases by over 4,900 MW from a normal 50/50 demand forecast as all of ERCOT's eight weather zones show simultaneous high levels of demand from higher temperatures. Even with the normal resource performance and low outages typically seen in ERCOT, the electricity demand from a wide-area heat event would likely lead to operating emergencies and a potential for unserved load.[7]

Currently, much of Texas is experiencing a drought, and projections for below-normal rainfall are cause for concern for electric reliability.[8] If drought conditions continue to deteriorate, the likelihood of the actual summer peak demand exceeding the forecast and/or generation derates due to low cooling lake levels increases. Generator outages are expected to increase during severe and prolonged drought conditions due to cooling water supply and temperature issues. These issues can cause forced outages of the thermal and wind fleet.

Generator performance in ERCOT is optimized for summer conditions, supporting reliable system performance despite relatively lower reserve margins. The generation fleet in ERCOT is a diverse mix of fuel types, including natural gas, nuclear, on-shore and coastal wind, solar, and a small amount of coal-fired generation. Some design choices, such as open-air thermal plants, provide optimum summer efficiency but may contribute to operating stress at other times. The availability of reliable, flexible generation is important to balancing system needs with a high penetration of variable, weather-dependent generation from wind and solar.

[7] See ERCOT's *2021 Summer Seasonal Assessment of Resource Adequacy (SARA)*: http://www.ercot.com/content/wcm/lists/219840/SARA-FinalSummer2021.pdf
[8] https://droughtmonitor.unl.edu/CurrentMap/StateDroughtMonitor.aspx?TX

WECC: Western Interconnection

Resource and energy adequacy is a significant concern for the summer across most of the Western Interconnection with overall capacity and demand projections for the area at similar levels to those seen in 2020 when a wide-area heat event caused energy emergencies and managed firm load loss. New flexible resources have been added in California and some plans for generation retirements have been put on hold to improve resource availability for periods of peak demand as well as for times when variable generation output falls off. However, peak demand projections have also increased in many parts of the Western United States, and overall resource capacity is lower compared to 2020 (see **Table 1**). Increased demand and lower resource capacity across the Western Interconnection can mean limited availability of surplus capacity for transfer into load centers for parts of California.

August 2020 Heatwave Event in the Western Interconnection

From August 14 through August 19, 2020, the Western United States suffered an intense and prolonged heatwave that affected many areas across the Western Interconnection.[9] Because of above-average temperatures, generation and transmission capacity struggled to keep up with increased electricity demand. Throughout many supply-constrained hours over this same period, generation resource output was below preseason peak forecasts for nearly all resource types, including natural gas, wind, solar, and hydro. During the event, 10 Western Interconnection BA issued 18 separate EEA. The impacts of the August heatwave struck the entirety of the Western Interconnection and caused a peak demand record of 162,017 MW on August 18, 2020, at 4:00 p.m. Mountain time. Although demand peaked on August 18, the most severe reliability consequence of the heatwave event occurred at the beginning, when 1,087 MW of firm load was shed on August 14 and 692 MW was shed on August 15 in California. An in-depth evaluation of the August 2020 Heatwave Event on BPS operations will be included in the 2021 State of Reliability report. The State of Reliability covers significant BPS events from the prior year and is typically published mid-year.

Table 1: Western Interconnection On-Peak Resource Adequacy

WECC - AB			
	2020 SRA	2021 SRA	2020 vs. 2021 SRA
Demand Projections	Megawatts (MW)	Megawatts (MW)	Net Change (%)
Total Internal Demand (50/50)	11,500	10,886	-5.3%
Net Internal Demand	11,500	10,886	-5.3%
Resource Projections	Megawatts (MW)	Megawatts (MW)	Net Change (%)
Existing-Certain Capacity	14,356	12,205	-15.0%
Anticipated Resources	14,356	13,928	-3.0%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	24.8%	27.9%	3.1
Reference Margin Level	10.4%	9.7%	-0.7
WECC - BC			
Demand, Resource, and Reserve Margins	2020 SRA	2021 SRA	2020 vs. 2021 SRA
Demand Projections	Megawatts (MW)	Megawatts (MW)	Net Change (%)
Total Internal Demand (50/50)	8,278	8,264	-0.2%
Net Internal Demand	8,278	8,264	-0.2%
Resource Projections	Megawatts (MW)	Megawatts (MW)	Net Change (%)
Existing-Certain Capacity	11,471	11,178	-2.6%
Anticipated Resources	11,686	11,363	-2.8%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference

[9] WECC August Heat Wave Event information provided by WECC's *August Heat Wave Analysis* Presentation

Table 1: Western Interconnection On-Peak Resource Adequacy			
Anticipated Reserve Margin	41.2%	37.5%	-3.7
Reference Margin Level	10.4%	9.7%	-0.7
WECC - CA/MX			
Demand, Resource, and Reserve Margins	2020 SRA	2021 SRA	2020 vs. 2021 SRA
Demand Projections	Megawatts (MW)	Megawatts (MW)	Net Change (%)
Total Internal Demand (50/50)	53,236	55,409	4.1%
Net Internal Demand	52,326	54,487	4.1%
Resource Projections	Megawatts (MW)	Megawatts (MW)	Net Change (%)
Existing-Certain Capacity	63,186	63,396	0.3%
Anticipated Resources	63,278	67,440	6.6%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	20.9%	23.8%	2.9
Reference Margin Level	13.7%	18.4%	4.7
WECC - NWPP-US & RMRG			
Demand, Resource, and Reserve Margins	2020 SRA	2021 SRA	2020 vs. 2021 SRA
Demand Projections	Megawatts (MW)	Megawatts (MW)	Net Change (%)
Total Internal Demand (50/50)	66,532	67,117	0.9%
Net Internal Demand	65,664	66,030	0.6%
Resource Projections	Megawatts (MW)	Megawatts (MW)	Net Change (%)
Existing-Certain Capacity	78,839	70,069	-11.1%
Anticipated Resources	80,457	77,210	-4.0%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	*	16.9%	*
Reference Margin Level	*	14.3%	*
WECC - SRSG			
Demand, Resource, and Reserve Margins	2020 SRA	2021 SRA	2020 vs. 2021 SRA
Demand Projections	Megawatts (MW)	Megawatts (MW)	Net Change (%)
Total Internal Demand (50/50)	25,145	24,751	-1.6%
Net Internal Demand	25,001	24,419	-2.3%
Resource Projections	Megawatts (MW)	Megawatts (MW)	Net Change (%)
Existing-Certain Capacity	29,440	26,850	-8.8%
Anticipated Resources	29,917	27,904	-6.7%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	19.7%	14.3%	-5.4
Reference Margin Level	10.0%	9.8%	-0.2

Responding to supply shortages from August 2020 and a directive from the California Public Utilities Commission, utilities in California have been procuring additional generating capacity for Summer 2021.[10] Existing on-peak capacity for the California-Mexico (CAMX) assessment area is 63.4 GW, a slight increase from 2020. However, a total of 3.4 GW of new resources are in late-stage planning for addition this summer; without these resources, the CAMX area will have an on-peak planning reserve margin of 17.6%, just short of the 18.4% Reference Margin Level target set by WECC for the area.[11] See **Figure 6** for peak hour existing certain and anticipated resource reserve margins for the Western Interconnection assessment areas.

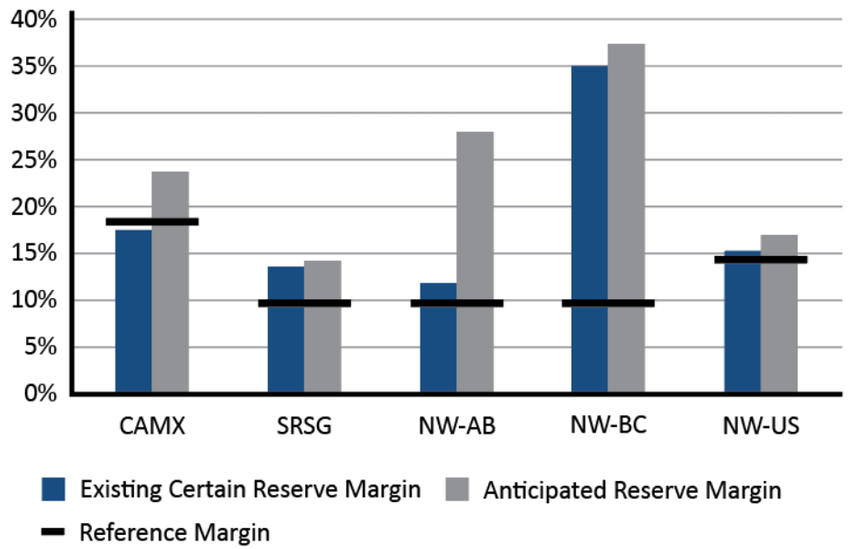


Figure 6: On-Peak Planning Reserve Margins in the Western Interconnection Assessment Areas

Most of the resource additions in California come in the form of new solar PV generation. These generation plants can provide energy to support peak demand; however, solar PV output falls off rapidly in late afternoon while summer demand often remains (see the discussion in the **Western Interconnection Risk Scenarios** section). Battery storage systems can supply energy to smooth the system ramping needs associated with high amounts of variable generation; by summer, nearly 600 MW of large-scale battery storage projects will have come on-line in California with an additional 800 MW expected by August 1.[12] The California Independent System Operator (CAISO) has performed significant work to support the integration of these new technologies into market and operating systems so that they will enhance grid reliability.

Throughout the Western Interconnection, BAs rely on flexible resources to support balancing the increasingly weather-dependent load with the variable generation within the resource mix. Dispatchable generation from hydroelectric and thermal plants internal to the BA's area as well as imports from surplus energy in another area are called upon by operators when area shortfalls are anticipated. Under normal

[10] See California Public Utilities Commission Emergency Reliability Rulemaking R.20-11-003

[11] WECC's Reference Margin Levels are based on a probabilistic approach for Loss-of-Load Probability (LOLP) less than or equal to 0.02% (approximately a 1-day-in-10-year loss of load). For more information see the *NERC 2020 Long-Term Reliability Assessment (LTRA)* Table 10: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2020.pdf

[12] A summary of resource additions in the CAISO area is found in Table 10 of the *CAISO Summer Loads and Resources Assessment, May 2021*: http://www.caiso.com/Documents/2021-Summer-Loads-and-Resources-Assessment.pdf

conditions, there is sufficient energy and resource capacity and an adequate transmission network for transfers between areas to meet system ramping needs. However, conditions such as wide-area heat events can reduce the availability of resources for transfer as areas serve higher internal demands. Additionally, transmission networks can become stressed when events such as wildfires or wide-area heatwaves cause network congestion. The growing reliance on transfers within the Western Interconnection and falling resource capacity in many adjacent areas increases the risk that extreme events will lead to load interruption.

Western Interconnection Risk Scenarios

Probabilistic studies performed by WECC identified a continued risk of energy shortfalls. For the upcoming summer, the WECC-CAMX area has 10,180 MWh of expected unserved energy (EUE) and the Northwest Power Pool and the Rocky Mountain Reserve Sharing Group (WECC-NWPP & RMRG) has 3,442 MWh of EUE; all other WECC areas have negligible EUE. WECC examined risk across a wide probability spectrum of potential combinations of high loads and low generation levels, with and without dependency on neighboring BA areas, and how deviations from those expected means would affect reliability.[13] The risk analysis charts in the **Regional Assessments Dashboards** illustrate the potential for above-normal peak demand and resource outage scenarios, similar to those seen in 2020, to result in operating emergencies in all WECC assessment areas with the exception of the winter-peaking Canadian provinces. For example, **Figure 7** is for the WECC CAMX area. Wide-area heatwave events can heighten energy shortfall risks throughout the Western Interconnection by reducing the availability of surplus capacity for sharing or by loading the transmission network to the limits of its transfer capability.

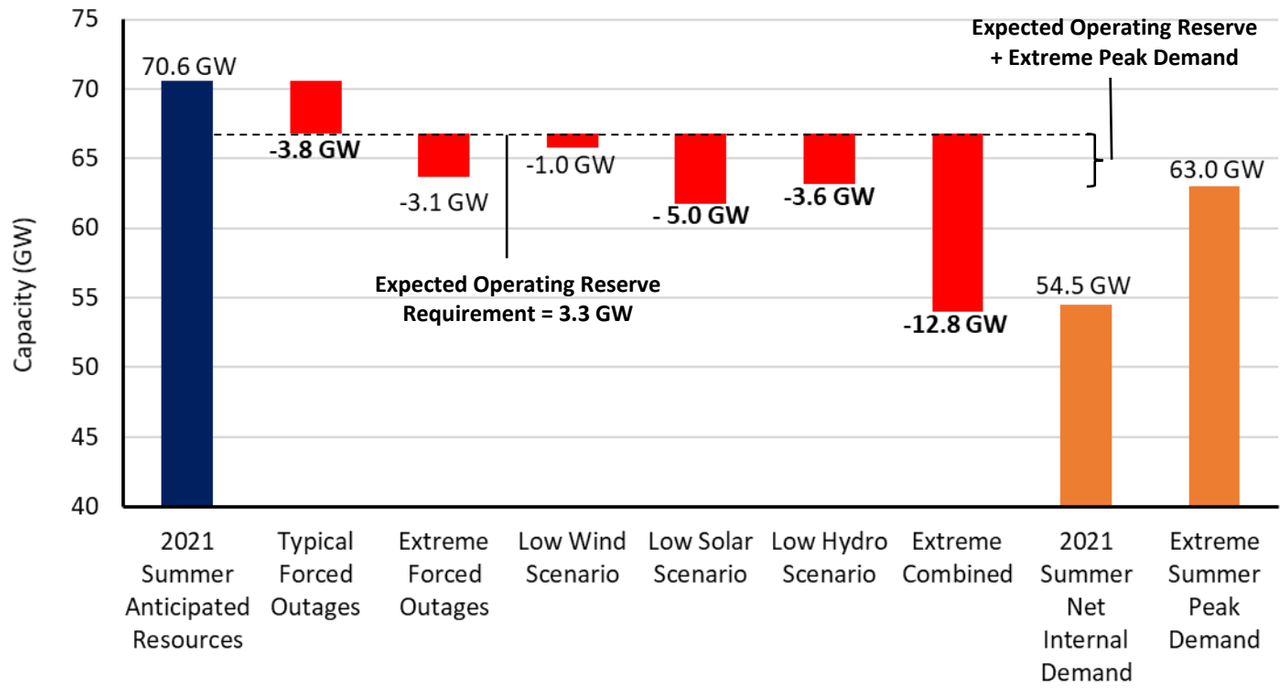


Figure 7: CAMX On-Peak Risk Scenario

[13] See *Western Assessment of Resource Adequacy Report*: Western Assessment of Resource Adequacy Report 12-18 (Final).pdf.pdf (wecc.org)

In summer, CAMX can be exposed to greater risk of resource shortfall for the hours that immediately follow the peak demand. The reason the risk is greater in these hours is that solar resource output is rapidly diminishing with the setting sun. Shown in the scenario depicted in Figure 8, anticipated resources are lower than on peak due to the reduced solar PV outputs. During periods of peak demand and normal forced outages, imports provide the needed energy to ensure demand and operating reserve requirements are met. Demand or resource derates from extreme conditions that cannot be satisfied with imports will result in energy emergencies and the potential for load shedding. Though trends for off-peak risk are increasing in other parts of the Western Interconnection, WECC's analysis indicates that greater risk exposure after the demand peak is only exhibited in CAMX.

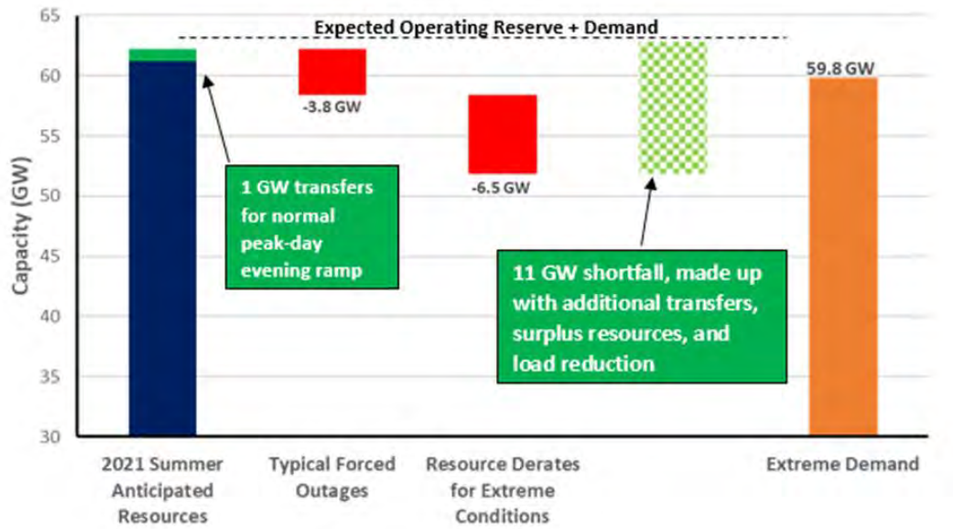


Figure 8: CAMX Highest Risk Hour Scenario (Hour Ending 7:00 p.m. Pacific Time)

Given that little has changed in the available electricity resources and the expected demand throughout the Western Interconnection, the summer-peaking areas remain at risk for localized shortfalls to exceed the availability of resource assistance and transmission deliverability during events like the 2020 August wide-area heat wave. Early generation and load forecasting based on long-term meteorological conditions will be important to maximize available generation and prepare load management plans for challenging weather. Enhancements to day-ahead markets and operational planning that were put in place and were effective in mitigating the impacts of the second, higher temperature heat wave that extended across the Western United States in September 2020 will need to be employed again to support BPS reliability in similar conditions.

Wildfire Impacts to the BPS in the Western Interconnections

Operation of the BPS can be impacted in areas where wildfires are active as well as areas where there is heightened risk of wildfire ignition due to weather and ground conditions. Wildfire prevention planning in California and other areas include power shut-off programs in high fire-risk areas. When conditions warrant implementing these plans, power lines (including transmission-level lines) may be preemptively de-energized in high fire-risk areas to prevent wildfire ignitions. Other wildfire risk mitigation activities include implementing enhanced vegetation management, equipment inspections, system hardening, and added

situational awareness measures. In January 2021, the Electric Reliability Organization published the *Wildfire Mitigation Reference Guide*[14] to promote preparedness within the North American electric power industry and share the experience and practices from utilities in the Western Interconnection.

On-Peak Planning Reserve Margins

The Anticipated Reserve Margin, which is based on available resource capacity, is a metric used to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecasted peak demand.[15] Large year-to-year changes in anticipated resources or forecasted peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. All assessment areas have sufficient Anticipated Reserve Margins to meet or exceed their Reference Margin Level for Summer 2021 (see **Figure 9**). Variable energy resources, including wind, solar, and types of hydro generation, often contribute significantly less of their installed capability at the period of peak demand. Consequently, the capacity contribution of variable energy resources to an areas anticipated resources may be a fraction of the installed capacity (see **Variable Energy Resource Contributions**).

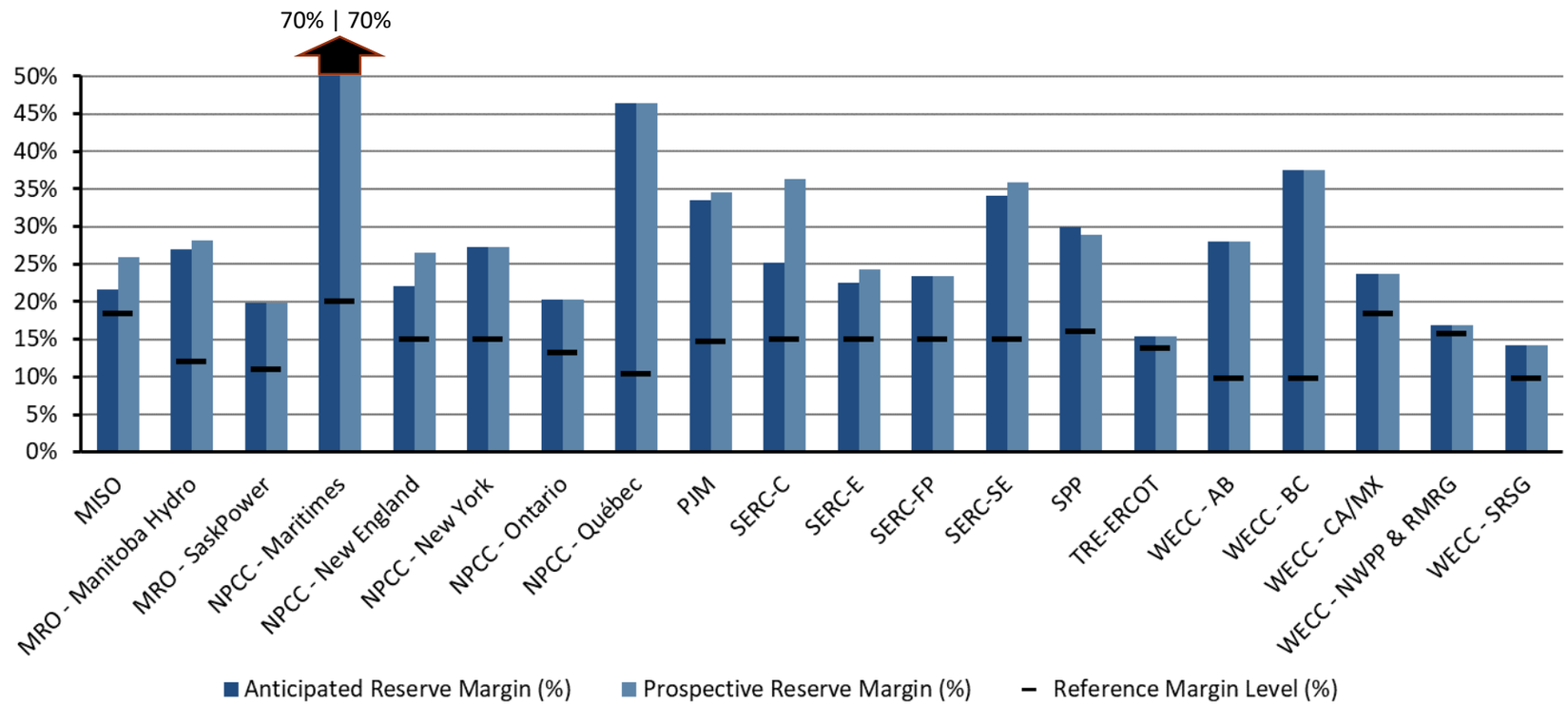


Figure 9: Summer 2021 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[14] See the NERC Wildfire Mitigation Reference Guide, January 2021: https://nerc.com/comm/RSTC/Documents/Wildfire%20Mitigation%20Reference%20Guide_January_2021.pdf

[15] Generally, anticipated resources include generators and firm capacity transfers that are expected to be available to serve load during electrical peak loads for the season. Prospective Resources are those that could be available but do not meet criteria to be counted as Anticipated Resources. Refer to the **Data Concepts and Assumptions** section for additional information on Anticipated/Prospective Reserve Margins, Anticipated/Prospective Resources, and Reference Margin Levels.

Changes from Year-to-Year

Understanding the changes from year-to-year can give insights for the upcoming season. Figure 10 provides the relative change from the Summer 2020 to the Summer 2021 period. The assessment area tables in the Demand and Resource Tables section provide details of the demand and resource components that make up the Anticipated Reserve Margins for each assessment area. In the following areas, Anticipated Reserve Margin changed by more than five percentage points, and none of the changes result in a resource adequacy concern for the upcoming summer:

- **MRO-Manitoba Hydro:** New hydro generators begin operation in May and July.
- **NPCC-Maritimes:** A decrease in demand-side management availability accounts for the majority of Anticipated Reserve Margin loss for the Maritimes footprint.
- **NPCC-New England, Québec, and WECC-SRSG:** Resources have fallen year-on-year with generation retirements.

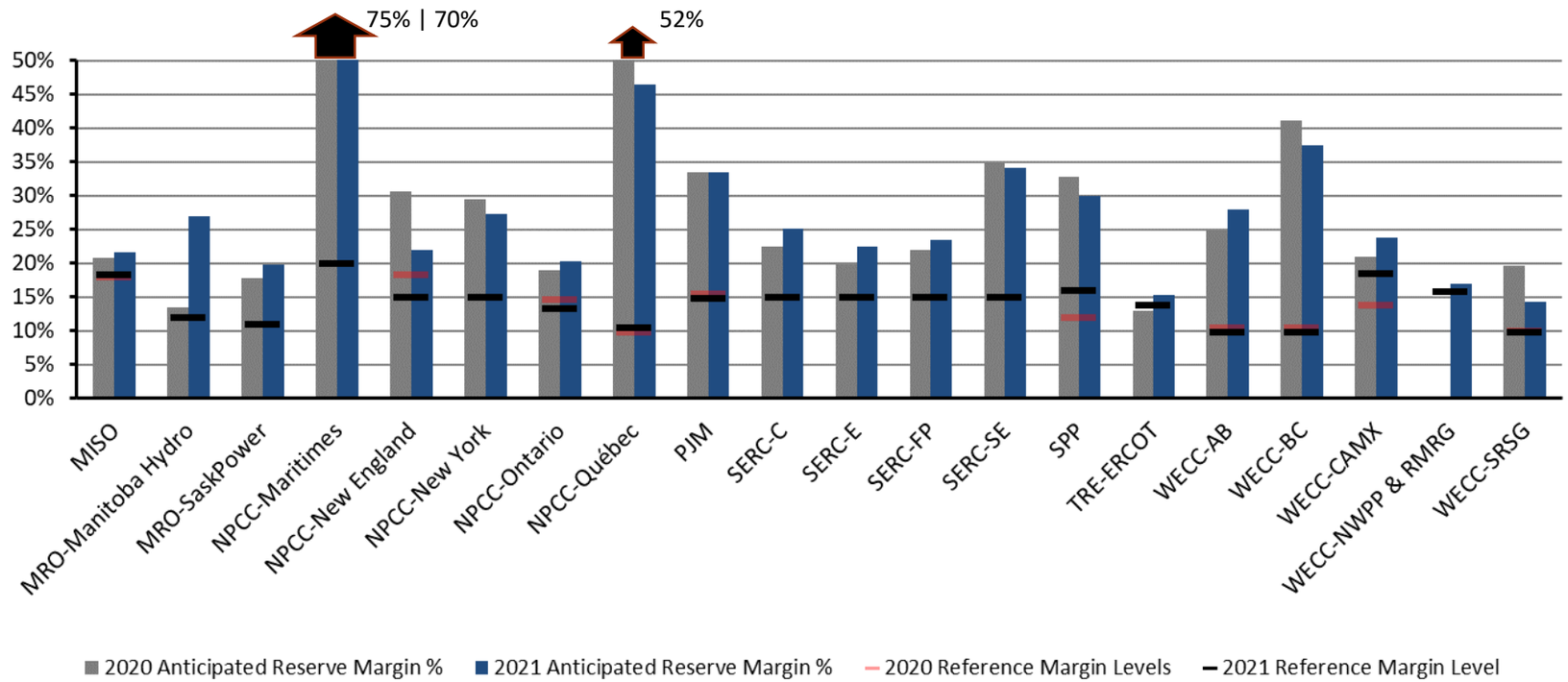


Figure 10: Summer 2020 to Summer 2021 Anticipated Reserve Margins Year-to-Year Change[16]

[16] WECC-NWPP and WECC-RMRG merged in 2020, so an Anticipated Reserve Margin or a Reference Margin Level was not produced for the 2020 assessment year for comparison.

Risk Assessments of Resource and Demand Scenarios

Areas can face energy shortfalls despite having Planning Reserve Margins that exceed Reference Margin Levels. Operating resources may be insufficient during periods of peak demand for reasons that could include generator scheduled maintenance, forced outages due to normal and more extreme weather conditions and loads, and low-likelihood conditions that affect generation resource performance or unit availability, including constrained fuel supplies. Grid operators employ operating mitigations or EEA (see Table 2) to obtain resources necessary to meet peak demands when operating resources are insufficient. The Regional Assessments Dashboards section in this report includes a seasonal risk scenario for each area that illustrates potential variation in resource and load as well as the potential effects that operating actions can have to mitigate shortfalls in operating reserves when insufficiencies occur.

About the Seasonal Risk Assessment

The operational risk analysis shown in the Regional Assessments Dashboards provides a deterministic scenario for understanding how various factors affecting resources and demand can combine to impact overall resource adequacy. Adjustments are applied cumulatively to anticipated capacity—such as reductions for typical generation outages (maintenance and forced not already accounted for in anticipated resources) and additions that represent the quantified capacity from operational tools, if any—that are available during scarcity conditions but have not been accounted for in the SRA reserve margins.

Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The effects from low-probability events are also factored in through additional resource derates or low-output scenarios and extreme summer peak load conditions. Because the seasonal risk scenario shows the cumulative impact resulting from the occurrence of multiple low-probability events, the overall likelihood of the scenario is very low.

Table 2: Energy Emergency Alert Levels

EEA Level	Description	Circumstances
EEA 1	All available generation resources in use	• The BA is experiencing conditions where all available generation resources are committed to meet firm load, firm transactions, and reserve commitments, and is concerned about sustaining its required contingency reserves. • Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
EEA 2	Load management procedures in effect	• The BA is no longer able to provide its expected energy requirements and is an energy deficient BA. • An energy deficient BS has implemented its operating plan(s) to mitigate emergencies. • An energy deficient BA is still able to maintain minimum contingency reserve requirements.
EEA 3	Firm Load interruption is imminent or in progress	• The energy deficient BA is unable to meet minimum contingency reserve requirements.

Transfers in a Wide-Area Event

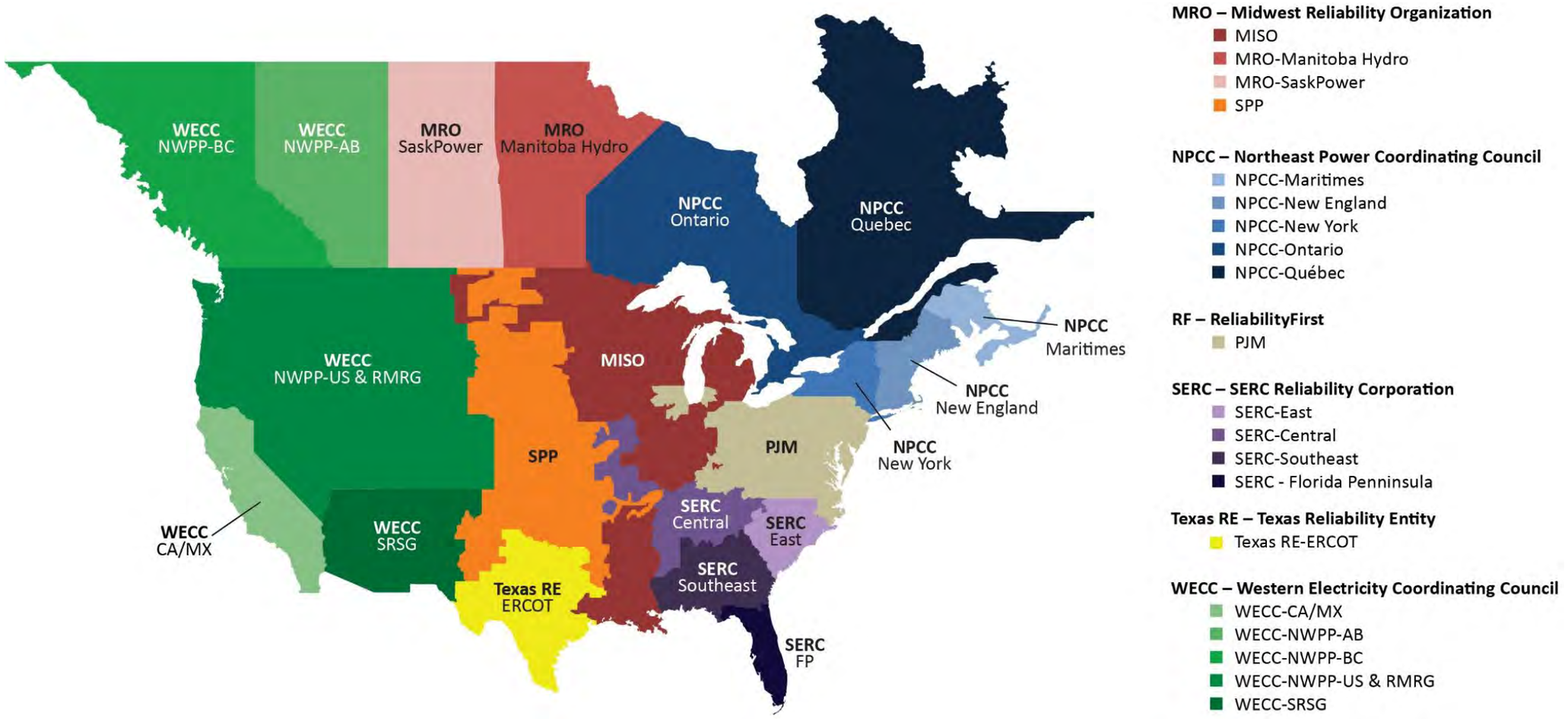
When above-normal temperatures extend over a wide area, resources can be strained in multiple assessment areas simultaneously, increasing the risk of shortfalls. Some assessment areas expect imports from other areas to be available to meet periods of peak demand and have contracted for firm transfer commitments. A summary of area firm on-peak imports and exports is shown in **Table 3**. Firm resource transactions, such as these, are accounted for in all assessment area anticipated resources and reserve margins. Areas with net imports show a positive transfer amount, and areas with net exports show a negative transfer amount. Only areas that contained transfers for the previous or upcoming summer seasons are shown in **Table 3**; the data in this table is sourced from the data adequacy tables in the **Data Concepts and Assumptions** section. In the unlikely event that multiple assessment areas are experiencing energy emergencies as could occur in a wide-area heatwave, some transfers may be at risk of not being fulfilled. Transfer agreements may include provisions that allow the exporting entity to prioritize serving native load. Loss of transfers could exacerbate resource shortages that occur from outages and derates.

Table 3: 2020 and 2021 On-Peak Net Firm Transfers

Assessment Area	2020 Summer Transfers (MW)	2021 Summer Transfers (MW)	Year-to-Year Change
MISO	2,795	2,979	6.6%
MRO-Manitoba	-1,526	-1,596	4.6%
MRO-SaskPower	125	125	0.0%
NPCC-Maritimes	-53	-57	7.5%
NPCC-New England	1,510	1,208	-20.0%
NPCC-New York	1,562	1,816	16.3%
NPCC-Ontario	0	80	N/A
NPCC-Quebec	-1,963	-1,995	1.6%
PJM	1,412	1,460	3.4%
SERC-C	-807	172	-121.3%
SERC-E	266	562	111.3%
SERC-FP	1,146	1,007	-12.1%
SERC-SE	-972	-1,115	14.7%
SPP	-1,244	186	-115.0%
TRE-ERCOT	817	210	-74.3%
WECC-AB	0	0	N/A
WECC-BC	0	0	N/A
WECC-CAMX	0	686	N/A
WECC-NWPP-US and RMRG	749	6,139	719.6%
WECC-SRSG	0	866	N/A

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six RE on an assessment area basis.



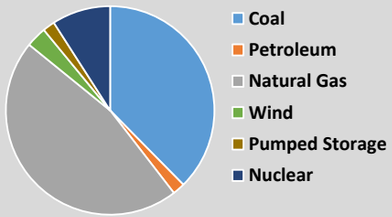


MISO

The Midcontinent Independent System Operator, Inc. (MISO) is a not-for-profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency.

MISO manages energy, reliability, and operating reserve markets that consist of 36 local BA and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three NERC RE, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

On-Peak Fuel Mix



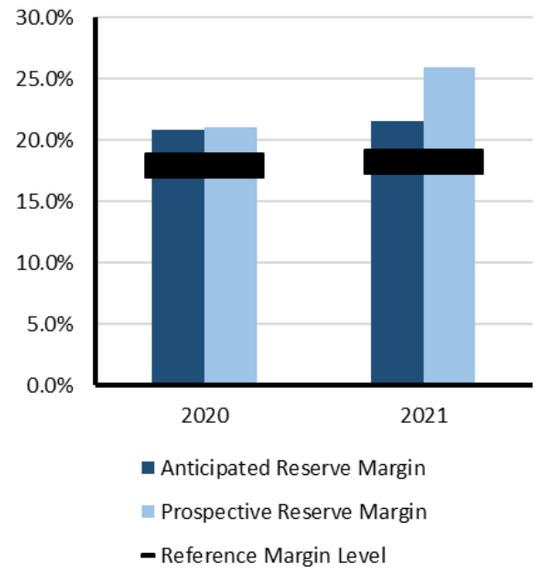
Highlights

- Summer scenarios with high resource outages and high demand may require use of load modifying resources (LMRs) and non-firm imports during peak periods. LMRs are an increasingly important segment of MISO resource portfolio. Operators designate resource constrained periods (Maximum Generation Events) to access LMRs.
- All MISO zones have met local capacity clearing requirements in the wholesale market auction and are projected to have sufficient resources for the summer.
- Covid-19 impacts on MISO load through late 2020 and the first quarter of 2021 have been much less pronounced than they were at the beginning of the pandemic. During the pandemic, MISO load has run 1–2% below normal in mild weather and 1–2% above normal in hotter weather. MISO expects load to trend close to normal through the summer; however, during a heatwave, load could trend 1–3% above normal due to increased residential demand.
- Based on probabilistic studies performed by MISO, the area has low amounts of EUE (18.6 MWh) for the summer season. Greatest risk occurs in the month of July, coinciding with the typical peak in annual demand.

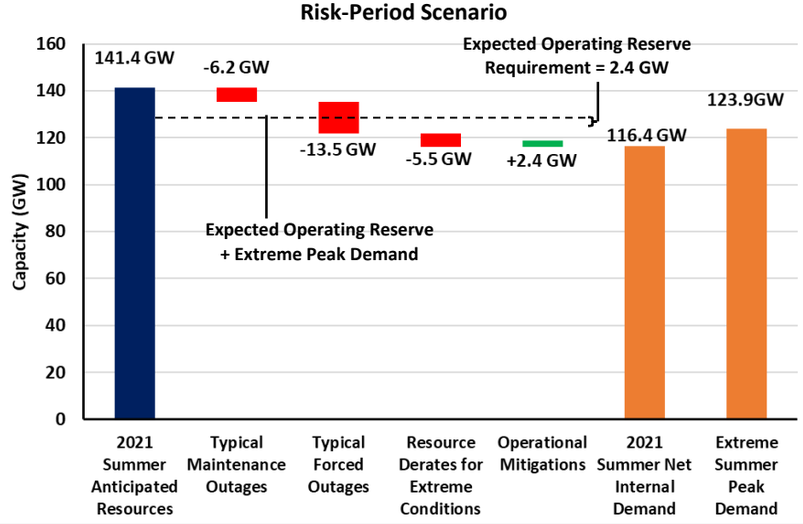
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, and short-term load interruption).

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description

- **Risk Period:** Highest risk for unserved energy at peak demand hour (late afternoon).
- **Demand Scenarios:** Net internal demand (50/50) and 90/10 demand forecast using 30 years of historical data
- **Maintenance Outages:** Rolling five-year average of maintenance and planned outages
- **Forced Outages:** Five-year average of all outages that were not planned
- **Extreme Derates:** Maximum of last five years of outages
- **Operational Mitigation:** A total of 2.4 GW capacity resources available during extreme operating conditions.

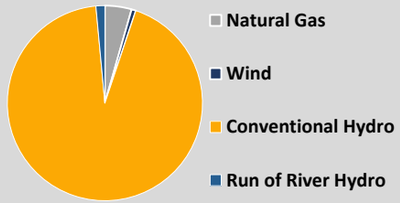


MRO-Manitoba Hydro

Manitoba Hydro is a provincial crown corporation that provides electricity to about 580,000 customers throughout Manitoba and natural gas service to about 282,000 customers in various communities throughout Southern Manitoba. The Province of Manitoba has a population of about 1.3 million in an area of 250,946 square miles.

Manitoba Hydro is winter-peaking. No change in the footprint area is expected during the assessment period. Manitoba Hydro is its own Planning Coordinator and BA. Manitoba Hydro is a coordinating member of MISO. MISO is the Reliability Coordinator for Manitoba Hydro.

On-Peak Fuel Mix



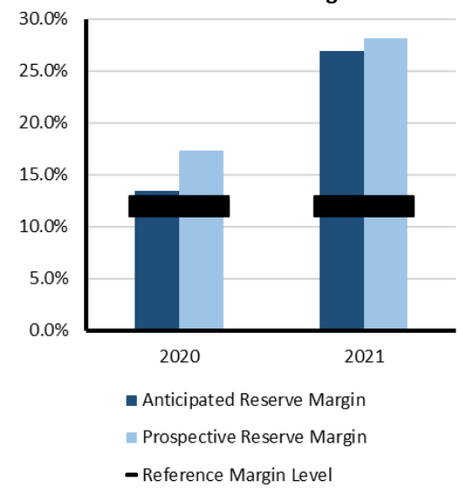
Highlights

- While the COVID-19 pandemic is expected to continue over the summer, no impact on area BPS reliability is anticipated as Manitoba Hydro has measures in place to minimize risk to operations. As of mid-March 2021, the pandemic situation in Manitoba appears stable with the implemented government measures.
- Reservoir storage levels are average and adequate to withstand the design drought.
- The first of seven Keeyask units is expected in May and the second is expected by July 1, 2021 (93 MW per unit).
- Based on the NERC 2020 Probabilistic Assessment (ProbA) and analysis of summer demand and resources, Manitoba Hydro is unlikely to experience resource shortages requiring operating procedures over the summer.

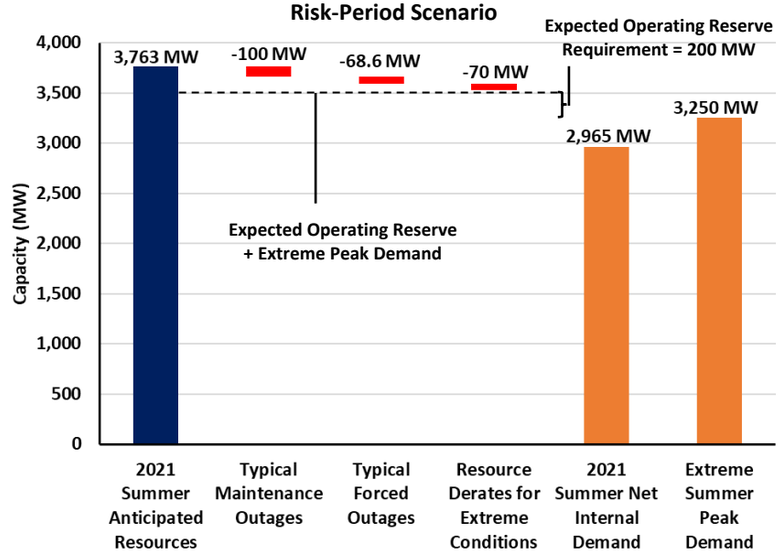
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description

- **Risk Period:** Periods of peak demand
- **Demand Scenarios:** Net internal demand (50/50) and minimum probability of exceedance forecast load
- **Outages:** Accounts for planned maintenance and average forced outages
- **Extreme Derates:** Capacity derate for thermal resources for extreme conditions.



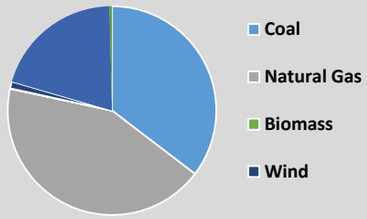
MRO-SaskPower

Saskatchewan is a province of Canada and comprises a geographic area of 651,900 square kilometers (251,700 square miles) with approximately 1.1 million people. Peak demand is experienced in the winter.

The Saskatchewan Power Corporation (SaskPower) is the Planning Coordinator and Reliability Coordinator for the province of Saskatchewan and is the principal supplier of electricity in the province.

SaskPower is a provincial crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan Bulk Electric System (BES) and its interconnections.

On-Peak Fuel Mix



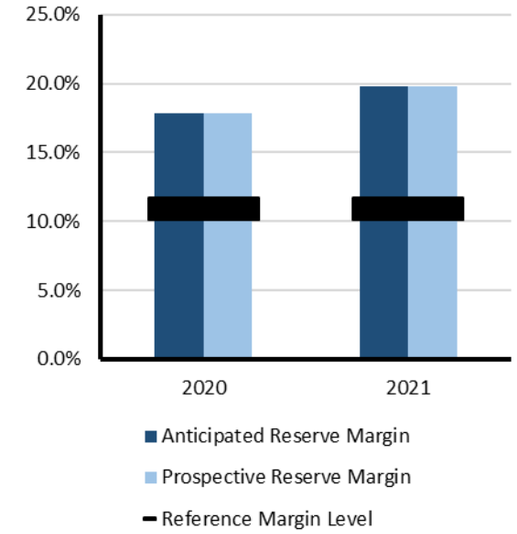
Highlights

- SaskPower experiences high load in summer as a result of hot weather.
- SaskPower conducts an annual summer joint operating study with Manitoba Hydro with inputs from Basin Electric (North Dakota) and prepares operating guidelines for any identified issues.
- Based on a SaskPower probability-based assessment, a low-likelihood scenario (1.8%) of capacity forced outages totaling 450 MW or greater that coincides with peak loads poses some risk of energy emergencies and unserved load. In the case of extreme hot weather conditions combined with large generation forced outages, SaskPower would use available demand response programs, short term power transfers from neighboring utilities, and short-term load interruptions. Risk is higher at the end of August to early October when larger amounts of generation maintenance is planned.

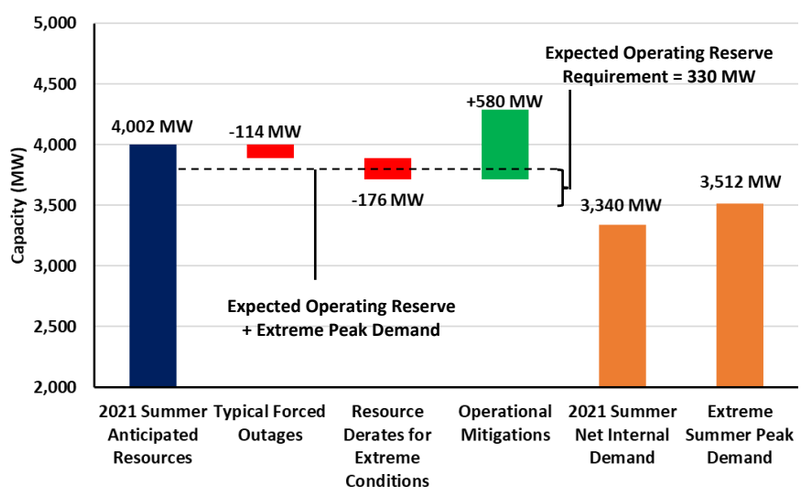
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, and short-term load interruption).

On-Peak Reserve Margins



Risk-Period Scenario



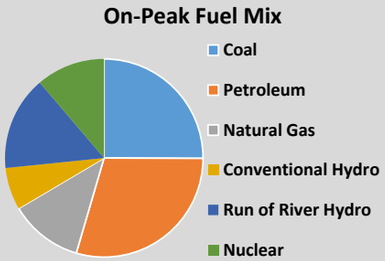
Scenario Description

- **Risk Period:** Periods of peak demand, afternoon (Risk is higher at the end of August to early October when more generation planned maintenance occurs.)
- **Demand Scenarios:** Net internal demand (50/50) and above-normal scenario based on peak demand with lighting and all consumer loads
- **Maintenance Outages:** Estimated based on averages from June-September 2020
- **Forced Outages:** Estimated using SaskPower forced outage model
- **Extreme Derates:** Estimated derate on natural gas units under extreme warm weather (>35 ˚C) based on historic performance and manufacturer data
- **Operational Mitigation:** Based on operational/emergency procedures



NPCC-Maritimes

The Maritimes assessment area is a winter-peaking NPCC area that contains two BA. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, and Prince Edward Island, and the northern portion of Maine, which is radially connected to the New Brunswick power system. The area covers 58,000 square miles with a total population of 1.9 million.

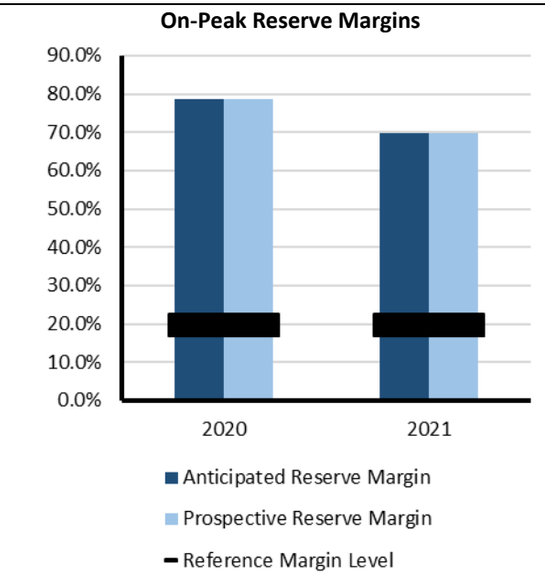


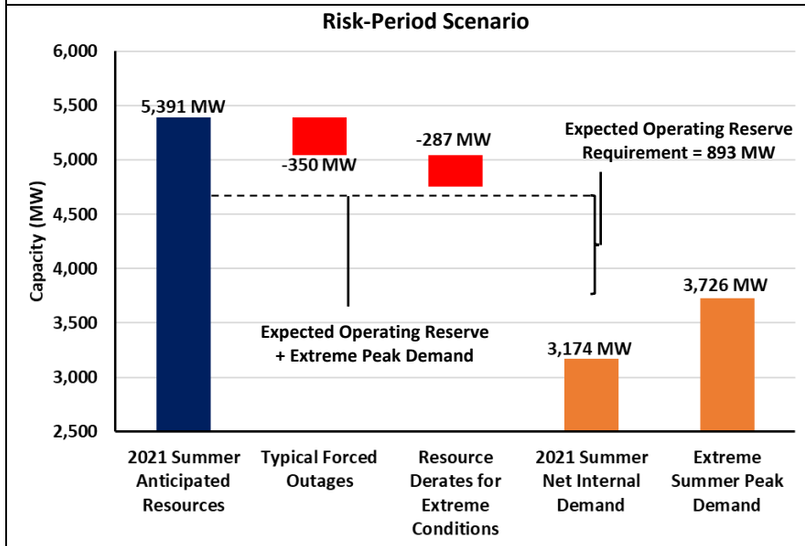
Highlights

- The Maritimes Area has not identified any operational issues that are expected to impact system reliability. If an event was to occur, there are emergency operations and planning procedures in place. All declared firm capacity is expected to be operational for the summer.
- As part of the planning process, dual-fueled units will have sufficient supplies of heavy fuel oil (HFO) on-site to enable sustained operation in the event of natural gas supply interruptions.
- The effects of the COVID-19 pandemic on load patterns, energy usage, and peak demands will continue to be evaluated during the pandemic.
- The Maritimes are evaluating contingency plans for transmission, distribution and generation planned work, planned maintenance, and forced outages to proceed conservatively while mitigating short term and longer term reliability risks.
- Based on an NPCC probabilistic assessment, the Maritimes assessment area is estimated to require a limited use of their operating procedures designed to mitigate resource shortages during Summer 2021. Negligible amounts of LOLE, LOLH, and EUE were estimated over the summer period for all the scenarios modeled.

Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.





Scenario Description

- **Risk Period:** Periods of peak demand
- **Demand Scenarios:** Net internal demand (50/50) and 90/10 demand forecast
- **Outages:** Based on historical operating experience
- **Extreme Derates:** A low-likelihood scenario resulting in no wind resources

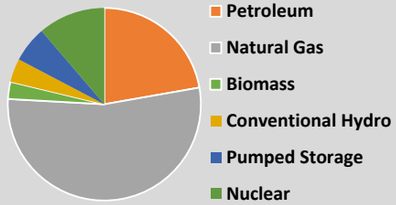


NPCC-New England

ISO New England (ISO-NE) Inc. is a regional transmission organization that serves the six New England states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. It is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administers the area's wholesale electricity markets, and manages the comprehensive planning of the regional BPS.

The New England BPS serves approximately 14.5 million customers over 68,000 square miles.

On-Peak Fuel Mix



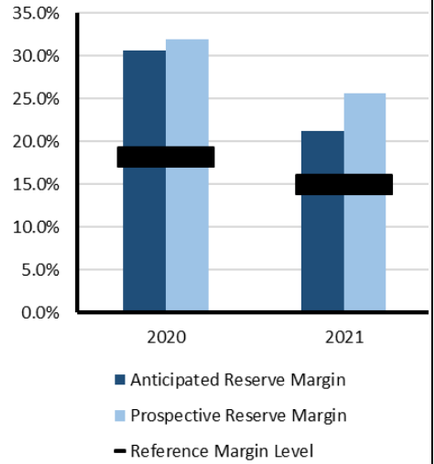
Highlights

- ISO New England (ISO-NE) expects to have sufficient resources to meet the area summer peak demand forecast. Peak summer demand is forecast to be 24,810 MW occurring the week of August 8 with a projected net margin of 1,910 MW (7.6%). The summer demand forecast takes into account the demand reductions associated with energy efficiency, load management, behind-the-meter photovoltaic systems, and distributed generation.
- ISO-NE is producing a weekly analysis of the impact the response to COVID-19 is having on New England system demand, posted on its external website every Tuesday.[17] ISO-NE will adjust forecasts based on trends.
- Based on an NPCC probabilistic assessment with scenarios, the New England assessment area is expected to require limited use of their operating procedures designed to mitigate resource shortages during Summer 2021. Negligible amounts of LOLE, LOLH, and EUE were estimated over the summer period for all the scenarios modeled except the severe low-likelihood case. The two highest peak load levels for this severe case resulted in LOLE of 0.3 days, with an associated LOLH of 1.3 hours, and an associated EUE of 868 MWh. This scenario is based exclusively on the two highest load levels representing an average 10–15% increase in peak loads over the 50/50 forecast with a combined 7% probability of occurrence. Additional constraints include 10% reduction in NPCC resources and PJM reductions.

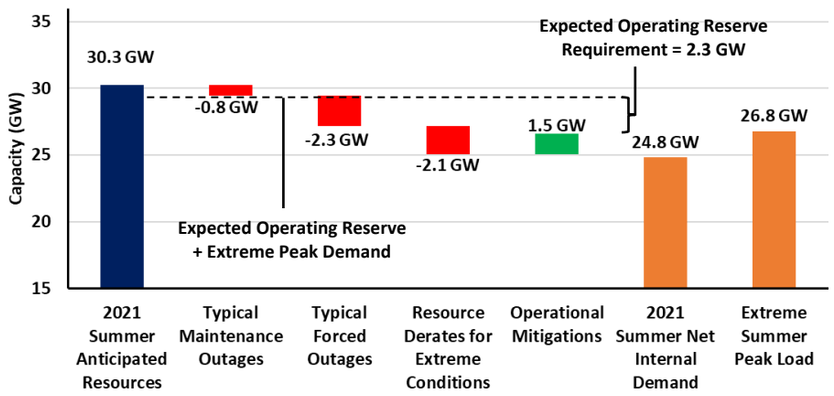
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, and short-term load interruption.)

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description

- **Risk Period:** Period of greatest risk coincides with peak demand (afternoon)
- **Demand Scenarios:** Net internal demand (50/50) and 90/10 demand forecast
- **Outages:** Based on weekly averages
- **Extreme Derates:** Represent a 90/10 case based on historical observation of force outages and additional reductions for generation at risk due to natural gas supply
- **Operational Mitigation:** Based on ISO-NE operating procedures

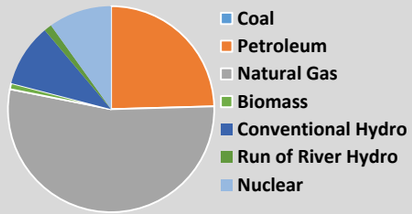
[17] https://www.iso-ne.com/markets-operations/system-forecast-status/estimated-impacts-of-covid-19-on-demand



NPCC-New York

The New York Independent System Operator (NYISO) is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. The New York Independent System Operator (NYISO) is the only BA within the state of New York. The BPS encompasses approximately 11,000 miles of transmission lines, 760 power generation units, and serves 19.5 million customers. New York experienced its all-time peak demand of 33,956 MW in Summer 2013. The NERC Reference Margin Level is 15%. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. However, New York requires load serving entities to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). NYSRC approved the 2020–2021 IRM at 20.7%."

On-Peak Fuel Mix



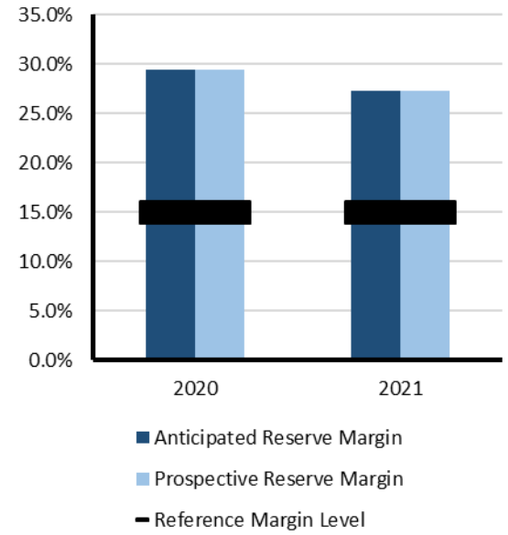
Highlights

- The NYISO is not anticipating any operational issues in the New York control area for the upcoming summer operating period. Adequate capacity margins are anticipated and existing operating procedures are sufficient to handle any issues that may occur.
- High capacity factors on certain New York City peaking units could result in possible violations of their daily NOx emission limits if they were to fully respond to the NYISO dispatch signals; this could occur during long duration hot weather events or following the loss of significant generation or transmission assets. Protocols with state agencies provide for reliable operation during emergencies.
- Based on an NPCC probabilistic assessment with scenarios, the New York assessment area is expected to require limited use of their operating procedures designed to mitigate resource shortages during Summer 2021. New York's LOLE risk is correlated to simultaneous high loads occurring in PJM, Ontario, and MISO, which limits the availability of external support. Negligible amounts of LOLE, LOLH, and EUE were estimated over the summer period for all the scenarios modeled except for the low-likelihood severe case that assumes simultaneous stressed system conditions for NPCC and the modeled external systems. The two highest peak load levels for this severe case resulted in an estimated LOLE of one occurrence in July, with an associated LOLH of four hours and an EUE of 3,020 MWh risk. The highest peak load level results were based exclusively on only the two highest load levels (representing on average 10–15% increase in peak loads over the 50/50 forecast) having a combined 7% chance of occurring. Additional constraints include 10% reduction in NPCC resources and PJM reductions.

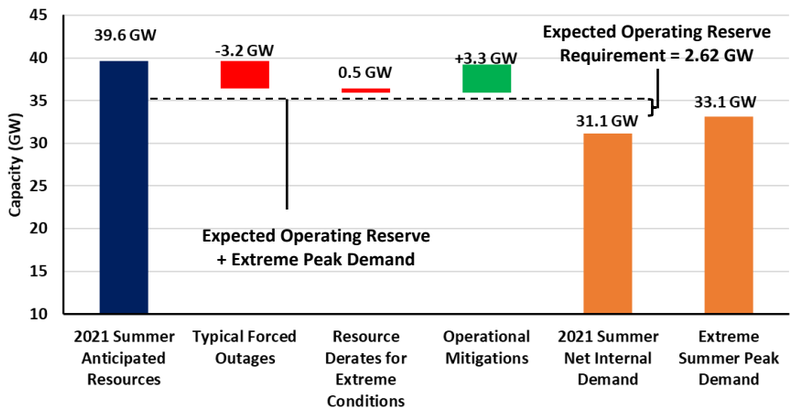
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description

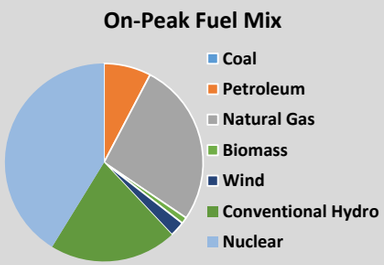
- **Risk Period:** Periods of peak demand
- **Demand Scenarios:** Net internal demand (50/50) and 90/10 demand forecast with demand response adjustments
- **Forced Outages:** Based on historical 5-year averages
- **Extreme Derates:** Capacity derate for thermal resources for extreme conditions
- **Operational Mitigation:** 3.3 GW based on operational/emergency procedures in area *Emergency Operations Manual*



NPCC-Ontario

The Independent Electricity System Operator (IESO) is the BA for the province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of more than 14 million.

Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

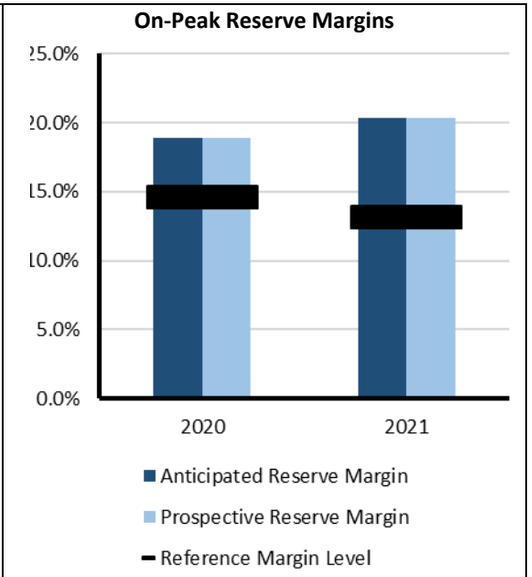


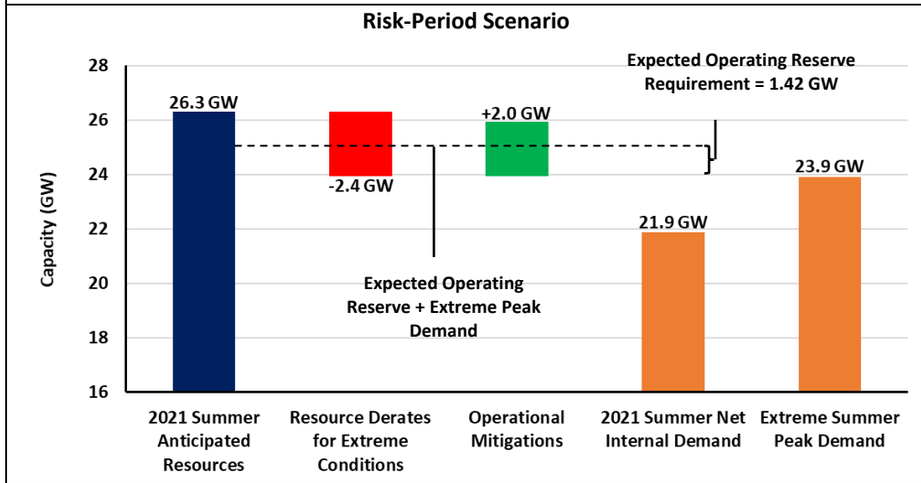
Highlights

- Ontario expects to have sufficient generation resources available to meet its needs throughout the summer, and its transmission system is expected to continue to reliably supply province-wide demand
- In December 2020, the IESO ran its first capacity auction, clearing 992.1 MW of capacity for the 2021 summer period. The capacity auction will be an important tool for meeting Ontario's future reliability needs.
- The ongoing transmission outage at the New York-St Lawrence interconnection continues to impact import and export capacity between Ontario and New York. The issue is being jointly managed by entities involved.
- Based on an NPCC probabilistic assessment, the Ontario assessment area is estimated to require a limited use of their operating procedures designed to mitigate resource shortages during Summer 2021. Ontario's LOLE risk is correlated to the availability of their external imports at the time of Ontario's peak load. Negligible amounts of LOLE, LOLH, and EUE were estimated over the summer period for all the scenarios modeled except the low-likelihood severe case and highest peak load levels (which resulted in an LOLE of 0.4 days with an associated LOLH of 1.2 hours and an associated EUE of 1,042 MWh risk in July). The highest peak load level results were based exclusively on only the two highest load levels of the seven modeled, having a combined 7% chance of occurring in this already low-likelihood case (with about a 10% reduction in NPCC resources and PJM reductions).

Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Extreme summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, and short-term load interruption).





Scenario Description

- **Risk Period:** Period of greatest risk coincides with peak demand (afternoon)
- **Demand Scenarios:** Net internal demand (50/50 Forecast) and highest weather-adjusted daily demand from 31 years of demand history
- **Forced Outages:** Estimated using market forced outage model
- **Extreme Derates:** Hydro derates are based on 2012 (dry-year) conditions. Thermal derates are estimated using an extreme temperature from 31 years of historical data.
- **Operational Mitigation:** Imports anticipated from neighbors during emergencies

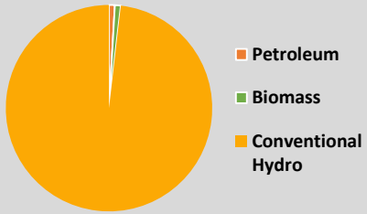


NPCC-Québec

The Québec assessment area (Province of Québec) is a winter-peaking NPCC area that covers 595,391 square miles with a population of 8 million.

Québec is one of the four NERC Interconnections in North America; it has ties to Ontario, New York, New England, and the Maritimes; consisting of either HVDC ties, radial generation, or load to and from neighboring systems.

On-Peak Fuel Mix



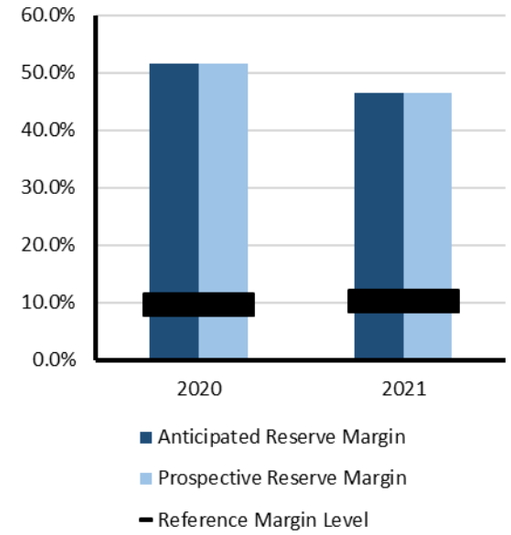
Highlights

- No issues are anticipated for the summer since the Québec system is winter peaking.
- Based on an NPCC probabilistic assessment, the Québec assessment area is not expected to require use of their operating procedures designed to mitigate resource shortages during Summer 2021. The Québec area is winter peaking and has a large reserve margin for the summer period; as a result, Québec did not demonstrate any measurable amounts of LOLE, LOLH, or EUE risk over the summer period for all the scenarios modeled.

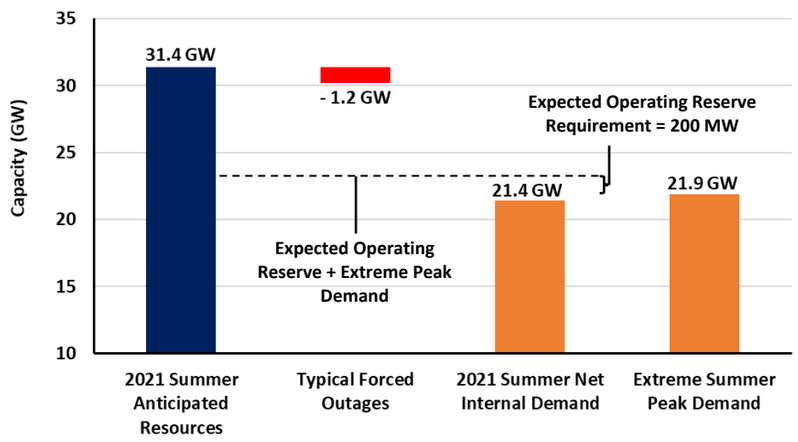
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description

- **Risk Period:** Period of peak demand (afternoons)
- **Demand Scenarios:** Net internal demand (50/50) and 90/10 demand forecast
- **Extreme Derates:** Rare scenario of 1,200 MW in unplanned outages

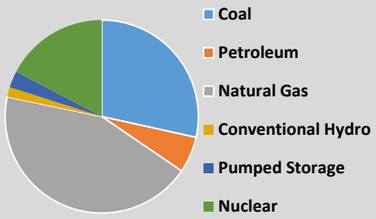


PJM

PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM serves 65 million people and covers 369,089 square miles.

PJM is a BA, Planning Coordinator, Transmission Planner, Resource Planner, Interchange Authority, Transmission Operator, Transmission Service Provider, and Reliability Coordinator.

On-Peak Fuel Mix



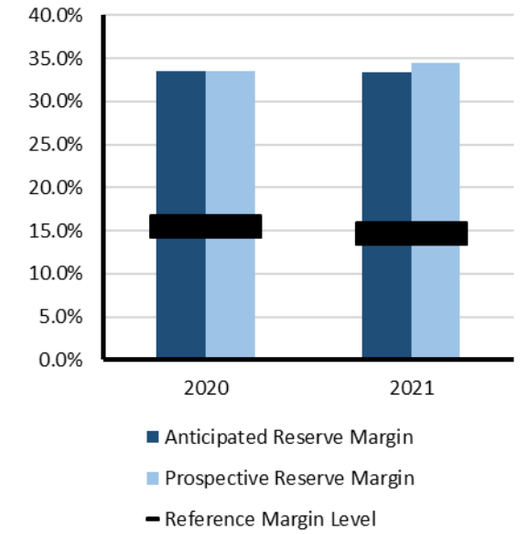
Highlights

- PJM expects no resource problems over the entire 2021 summer peak season. Installed capacity is almost double the Reference Margin Level and there are currently no known deliverability restrictions.
- Probabilistic studies performed by PJM indicate that there is low risk of resource shortfall for summer. The analysis included a range of load, generation, and outage scenarios.
- PJM's Reference Margin Level decreased from 15.1% to 14.9% due to lower average expected forced outage rates in the 2020 PJM capacity model compared to prior years.

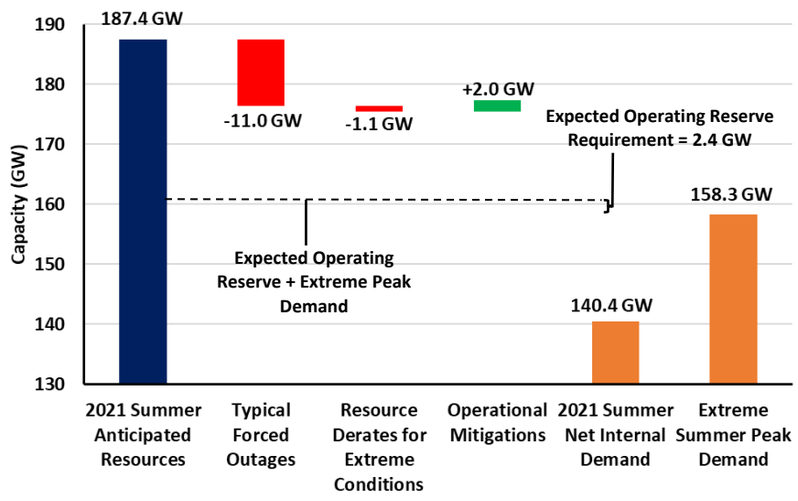
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description

- **Risk Period:** Highest risk for unserved energy at peak demand hour (afternoon)
- **Demand Scenarios:** Net internal demand (50/50) and 90/10 demand forecast
- **Outages:** Based on historical data and trending
- **Extreme Derates:** Derate accounts for reduced thermal capacity contributions due to performance in extreme conditions
- **Operational Mitigation:** A total of 2 GW obtained through emergency requests for behind-the-meter generation dispatch



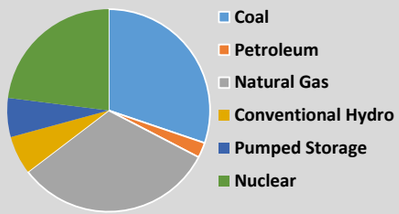
SERC-East

SERC-East is a summer-peaking assessment area within the SERC RE. SERC-East includes North Carolina and South Carolina.

SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the southeastern and central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million.

The SERC RE includes 36 BA, 28 Planning Authorities, and 6 Reliability Coordinators.

On-Peak Fuel Mix



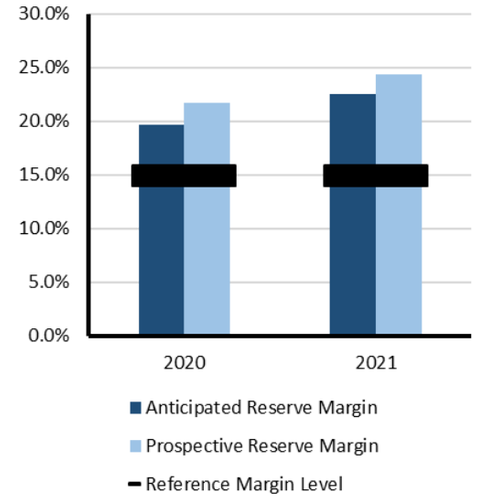
Highlights

- Entities in SERC-East have not identified any potential reliability issues for the upcoming season. The entities continue to perform resource studies to ensure resource adequacy to meet the summer peak demand and to maintain reliability to the system. Entities reported that coal inventory is in the upper allowed range to maintain reliability.
- Entities in the SERC RE continue to participate actively in the SERC Near-Term and Long-Term Working Groups. These groups identify emerging and potential reliability impacts to transmission and resource adequacy as well as with transfer capability.
- Entities in SERC-East are not anticipating operational challenges for the upcoming summer season.
- Probabilistic analysis performed for SERC-East shows almost no risk for resource shortfall for the summer. SERC-East has a small amount of EUE in August but a negligible amount at other times (EUE < 0.4 MWh).

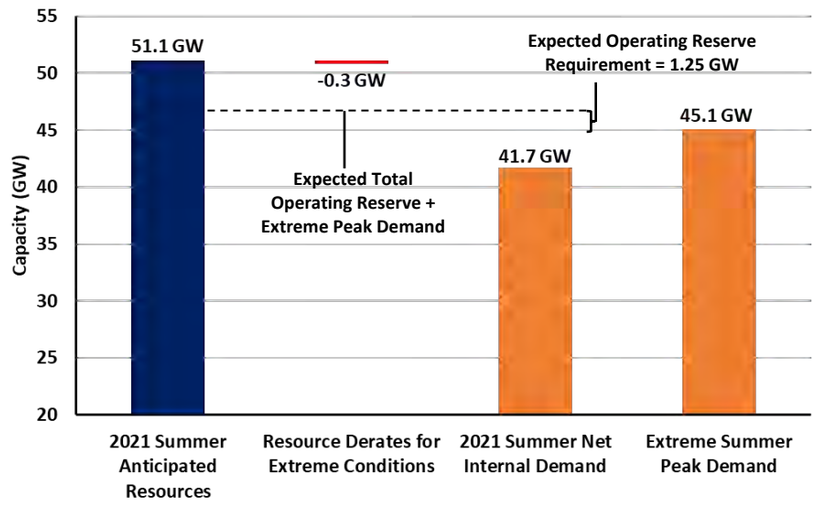
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description

- **Risk Period:** Highest risk for unserved energy at peak demand hour (afternoon)
- **Demand Scenarios:** Net internal demand (50/50) and 90/10 demand forecast
- **Forced Outages:** Weighted average forced outage rates on-peak are factored into the anticipated resources calculation
- **Extreme Derates:** Account for reduced thermal capacity contributions due to performance in extreme conditions



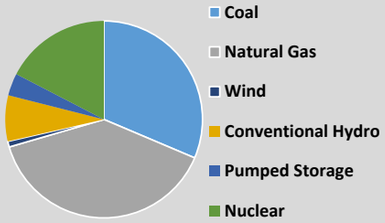
SERC-Central

SERC-Central is a summer peaking assessment area within the SERC RE. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, and Kentucky.

SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the southeastern and central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million.

The SERC RE includes 36 BA, 28 Planning Authorities, and 6 Reliability Coordinators.

On-Peak Fuel Mix



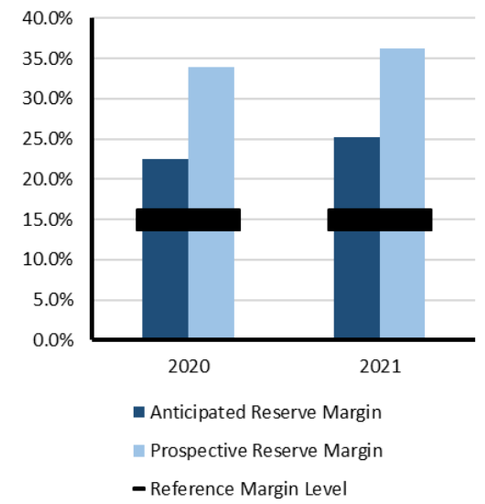
Highlights

- Entities in SERC-Central have not identified any potential reliability issues for the upcoming season. Entities have noted that planned outages are on schedule to be completed prior to the summer season and not anticipated to result in potential reliability issues.
- Entities in the SERC RE continue to participate actively in the SERC Near-Term and Long-Term Working Groups. These groups identify emerging and potential reliability impacts to transmission and resource adequacy along with transfer capability.
- Probabilistic analysis performed for SERC-Central shows low risk for resource shortfall for the summer. Load loss and unserved energy indices are negligible for SERC-Central.

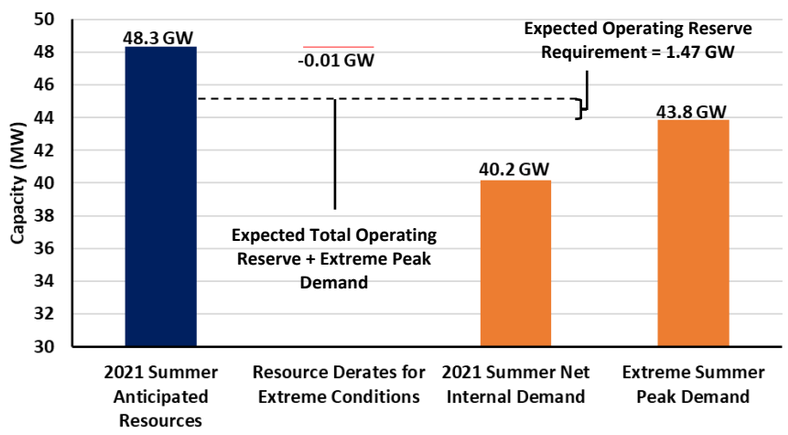
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description

- **Risk Period:** Highest risk for unserved energy at peak demand hour (afternoon)
- **Demand Scenarios:** Net internal demand (50/50) and 90/10 demand forecast
- **Forced Outages:** Weighted average forced outage rates on-peak are factored into the anticipated resources calculation
- **Extreme Derates:** Account for reduced thermal capacity contributions due to performance in extreme conditions



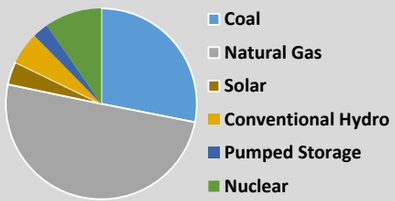
SERC-Southeast

SERC-Southeast is a summer peaking assessment area within the SERC RE. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi.

SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the southeastern and central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million.

The SERC RE includes 36 BA, 28 Planning Authorities, and 6 Reliability Coordinators.

On-Peak Fuel Mix



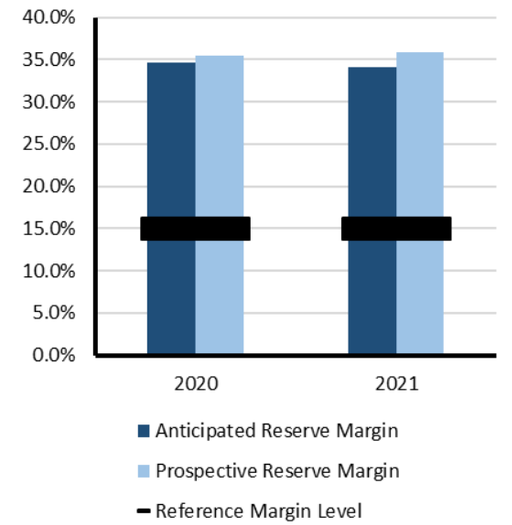
Highlights

- Entities in SERC Southeast have not identified any emerging reliability issues for the upcoming season that will impact resource adequacy. The available system capacity for the upcoming season meets or exceeds the reserve margin target. Reliability is supported by a diverse fuel mix, firm gas contracts, and power purchases.
- Entities in the SERC area continue to participate actively in the SERC Near-Term and Long-Term Working Groups. These groups identify emerging and potential reliability impacts to transmission and resource adequacy along with transfer capability.
- Probabilistic analysis performed for SERC-Southeast shows there is low risk for resource shortfall for the summer. Load loss and unserved energy indices are negligible for SERC-Southeast throughout the summer.

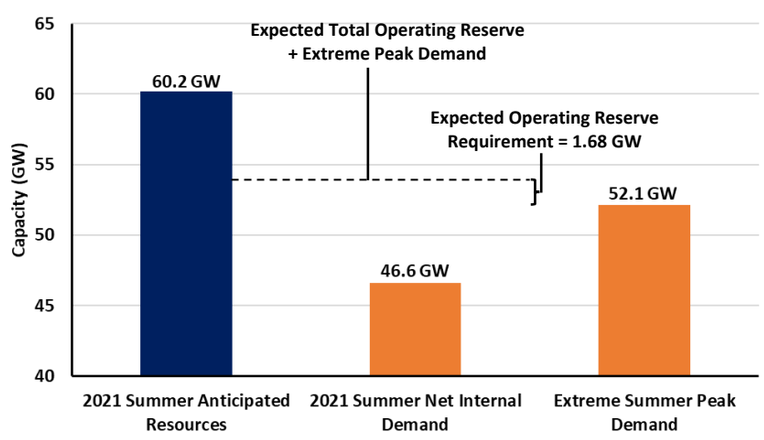
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description

- **Risk Period:** Highest risk for unserved energy at peak demand hour (afternoon)
- **Demand Scenarios:** Net internal demand (50/50) and 90/10 demand forecast
- **Forced Outages and Extreme Derates:** All outages and derates are factored into the anticipated resources calculation



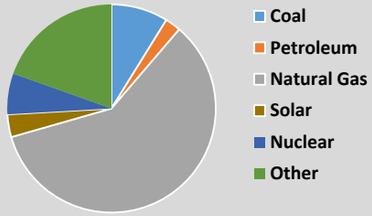
SERC-Florida Peninsula

SERC-Florida Peninsula is a summer peaking assessment area within the SERC RE.

SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the southeastern and central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million.

The SERC RE includes 36 BA, 28 Planning Authorities, and 6 Reliability Coordinators.

On-Peak Fuel Mix



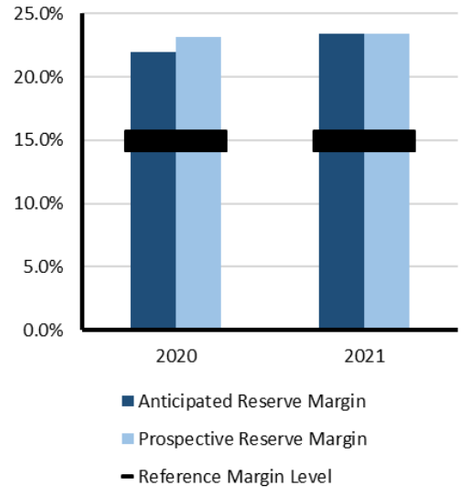
Highlights

- Entities in SERC-Florida Peninsula have not identified any emerging reliability issues or operational concerns for the upcoming summer. Entities in the SERC Region continue to participate actively in the SERC Near-Term and Long-Term Working Groups. These groups identify emerging and potential reliability impacts to transmission and resource adequacy along with transfer capability.
- Entities within the Florida Peninsula area have reported no operational challenges for the upcoming summer season based on current expected system conditions, the BES within the Florida Peninsula is expected to perform reliably for the anticipated 2021 summer season.
- Probabilistic analysis performed for SERC-Florida Peninsula shows there is low risk for resource shortfall for the summer. Load loss and unserved energy indices for SERC-Florida Peninsula are spread across the summer months but are relatively low (LOLH < 0.03 and EUE < 18 MWH).

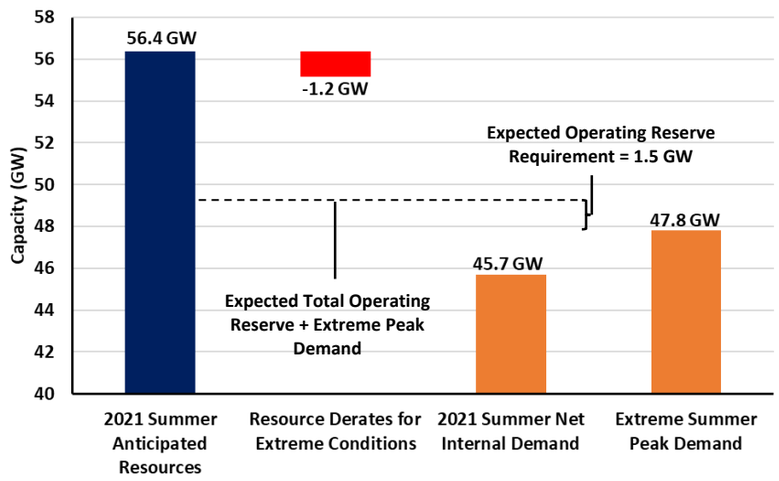
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description

- **Risk Period:** Highest risk for unserved energy at peak demand hour (afternoon)
- **Demand Scenarios:** Net internal demand (50/50) and 90/10 demand forecast
- **Forced Outages:** Weighted average forced outage rates on-peak are factored into the anticipated resources calculation
- **Extreme Derates:** Account for reduced thermal capacity contributions due to performance in extreme conditions

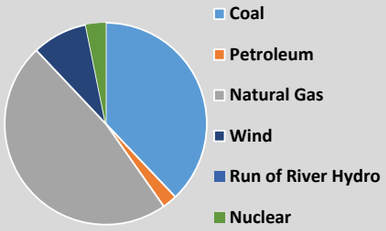


SPP

Southwest Power Pool (SPP) Planning Coordinator footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming.

The SPP long-term assessment is reported based on the Planning Coordinator footprint, which touches parts of the Midwest Reliability Organization RE, and the WECC RE. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million.

On-Peak Fuel Mix



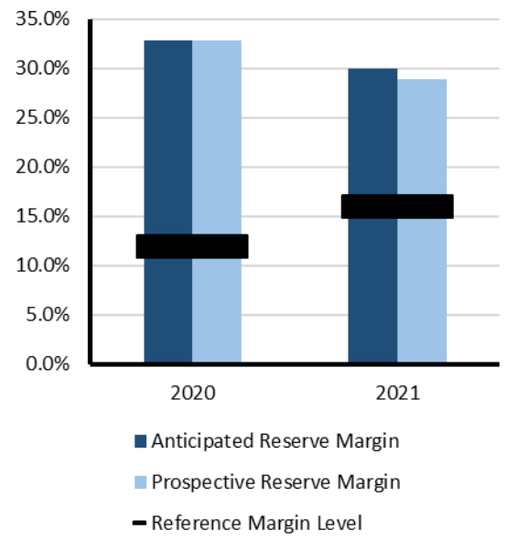
Highlights

- At this time, SPP does not anticipate any emerging reliability issues impacting the area for the 2021 summer season.
- Wind generation occupies a greater share of the SPP resource mix, requiring increased attention to weather-dependent forecasts. The SPP Uncertainty Response Team uses historical data to predict and develop mitigation plans for load forecast errors up to seven days in advance. Potential errors are predicted based on the levels of expected load, wind, and traditional resource outage in forecast. Mitigation may be obtained by scheduling longer-lead resources, controlling planned outages, and communicating with owners and operators.
- Using the current operational processes and procedures, SPP will continue to assess the needs for the 2021 summer season and will adjust as needed to ensure that real time reliability is maintained throughout the summer time frame.
- Probabilistic studies performed by SPP indicate for the 2021 summer season indicate that the current Planning Reserve Margin is sufficient for the 2021 summer season.

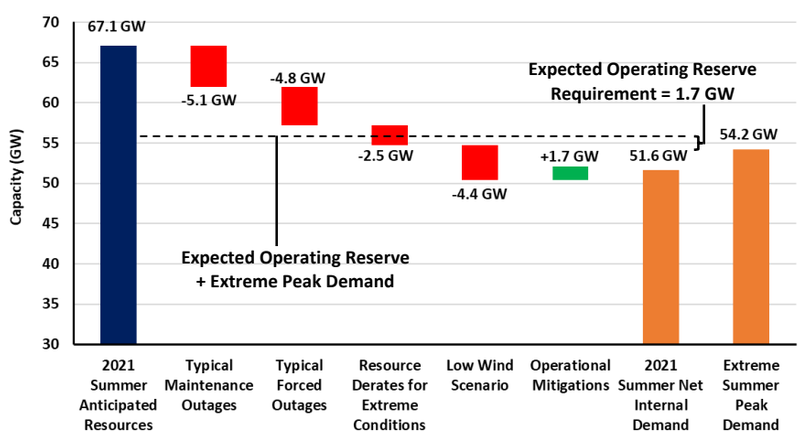
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Extreme summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, and short-term load interruption).

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description

- **Risk Period:** Highest risk for unserved energy at peak demand hour (late afternoon)
- **Demand Scenarios:** Net internal demand (50/50) and 90/10 demand forecast
- **Maintenance Outages:** Based on historical summer average for the past three years
- **Forced Outages:** Based on historical summer average for the past three years
- **Extreme Thermal Derates:** Derate accounts for reduced capacity contributions due to performance in extreme conditions
- **Low-Wind Scenario:** Rare scenario with only 320 MW (of 26,800 MW installed capacity) contributing to meet demand
- **Operational Mitigation:** 1,700 MW based on operational/emergency procedures

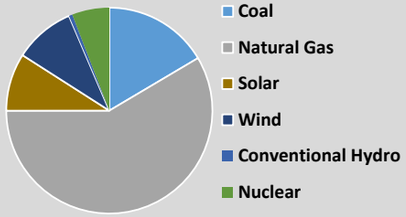


Texas RE-ERCOT

The Electric Reliability Council of Texas (ERCOT) is the ISO for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature.

ERCOT is a summer-peaking RE that covers approximately 200,000 square miles, connects over 46,500 miles of transmission lines, has over 710 generation units, and serves more than 25 million customers. Lubbock Power & Light joins the ERCOT grid on June 1, 2021. Texas RE is responsible for the RE functions described in the *Energy Policy Act of 2005* for the ERCOT RE.

On-Peak Fuel Mix



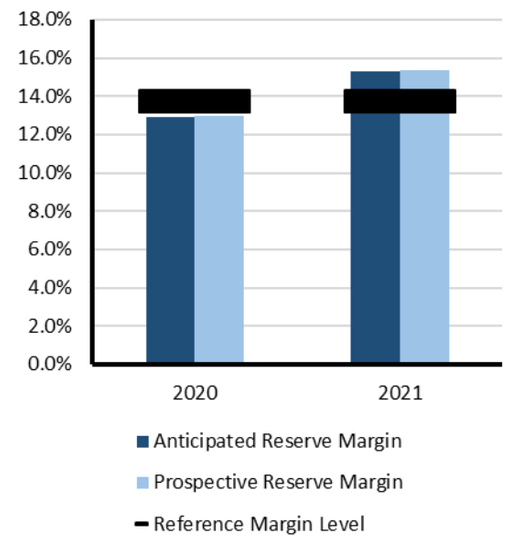
Highlights

- Summer probabilistic analysis performed by ERCOT indicates that the risk of unserved energy is low. Hour-ending 5:00 p.m. continues to be ERCOT's highest-risk hour for unserved energy with the likelihood of unserved energy less than 0.2%.
- Variable energy resources from wind and solar are critical to meeting peak electricity demand in ERCOT. Periods of low wind generation or higher-than expected thermal outages create a reliability risk during peak load hours. ERCOT appears to be in a weather cycle that may increase the risk of intensifying drought conditions and higher than normal summer temperatures. These weather factors could result in actual summer peak demand exceeding the forecast, which already anticipates record peak demand levels. Thermal outages may increase during severe and prolonged drought conditions due to cooling water supply and temperature issues.
- Given an Anticipated Reserve Margin of 15.3% and Reference Reserve Margin of 13.75%, ERCOT expects to have sufficient operating reserves for summer system conditions.
- Delays or cancellations of planned transmission expansion projects in the western part of the Lower Rio Grande Valley, if they occur, may contribute to potential localized reliability concerns.

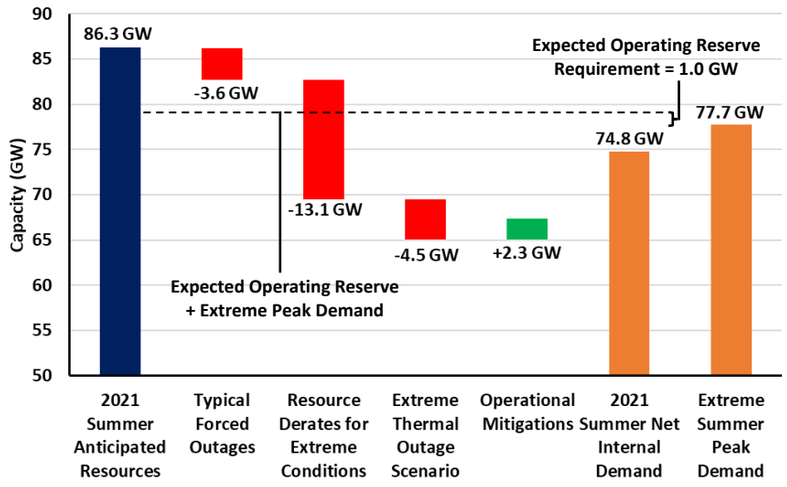
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, and short-term load interruption).

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description

- **Risk Period:** Highest risk for unserved energy at peak demand hour, late afternoon (Risk can extend for 1–2 hours after peak as solar PV output diminishes. Periods of low-wind, which usually occur 1–2 hours before peak demand, can also result in extended shortfall risk.
- **Demand Scenarios:** Net internal demand (50/50) and extreme demand based on 2011 historic summer peak demand (approximates 90/10 demand forecast)
- **Forced Outages:** Based on historical average of forced outages for June through September weekdays, hours ending 3:00–8:00 p.m., for the last three summer seasons (2018–2020)
- **Extreme Derates:** Additional derates of 2,605 MW (thermal), 6,576 MW (wind), and 2,953 MW (PV) for extreme conditions (i.e., based on the 95th percentile of historical forced outages for June–September weekdays, hours ending 3:00–8:00 p.m., for the last three years.
- **Extreme Outage Scenario:** Additional increments of thermal and hydro forced outages equating to highest hourly forced outages from 2011–2021 **(**When combined with extreme derates shown in the Risk-Period Scenario, it represents a very rare resource condition.)
- **Operational Mitigation:** Additional resources, primarily from load resources, but also switchable generation, additional imports, and voltage reduction)



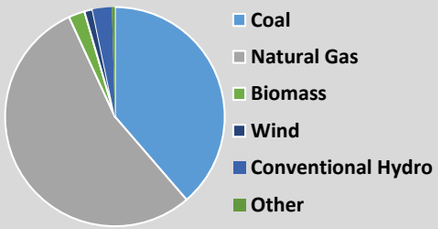
WECC-AB

WECC-Alberta is an assessment area in the WECC RE that consists of the province of Alberta, Canada.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members, which include 38 BA, represent a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million people, it is geographically the largest and most diverse of the NERC RE.

WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 Western United States in between.

On-Peak Fuel Mix



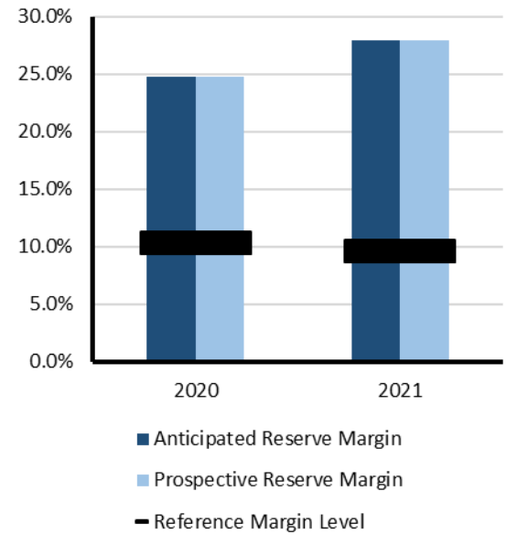
Highlights

- WECC-Alberta is a winter peaking province. Sufficient resources are anticipated to meet summer demand.
- Based on a WECC probabilistic assessment, the WECC-AB assessment area had negligible LOLH and EUE.

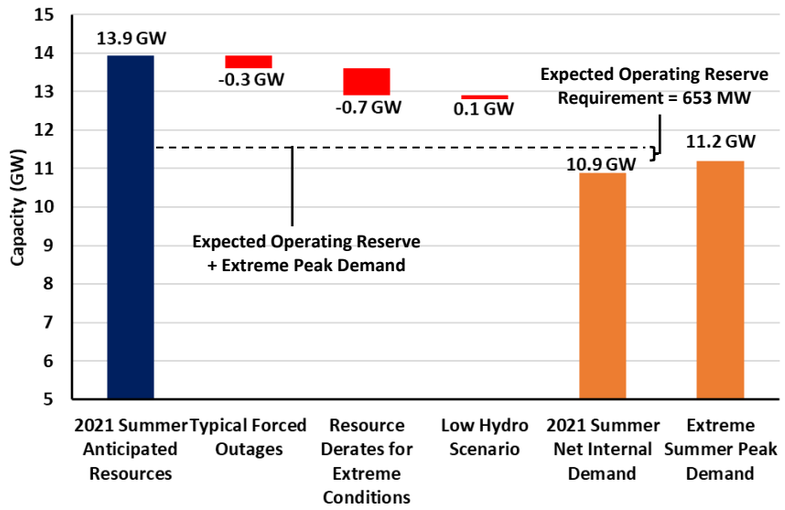
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description

- **Risk Period:** Highest risk for unserved energy at peak demand hour (afternoon)
- **Demand Scenarios:** Net internal demand (50/50) and 90/10 demand forecast
- **Forced Outages:** Average seasonal outages
- **Extreme Derates:** Derate using 90/10 scenario



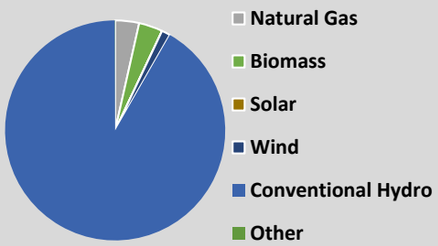
WECC-BC

WECC-British Columbia is an assessment area in the WECC RE that consists of the province of British Columbia, Canada.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members, which include 38 BA, represent a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million people, it is geographically the largest and most diverse of the NERC RE.

WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 Western United States in between.

On-Peak Fuel Mix



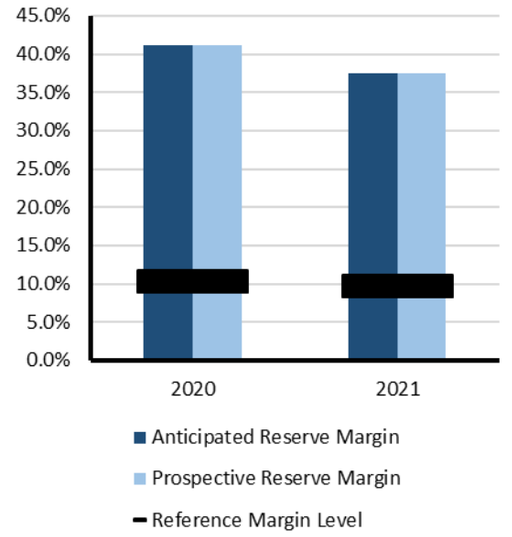
Highlights

- WECC-British Columbia is a winter peaking province. Sufficient resources are anticipated to meet summer demand.
- Based on a WECC probabilistic assessment, the WECC-AB assessment area had negligible LOLH and EUE.

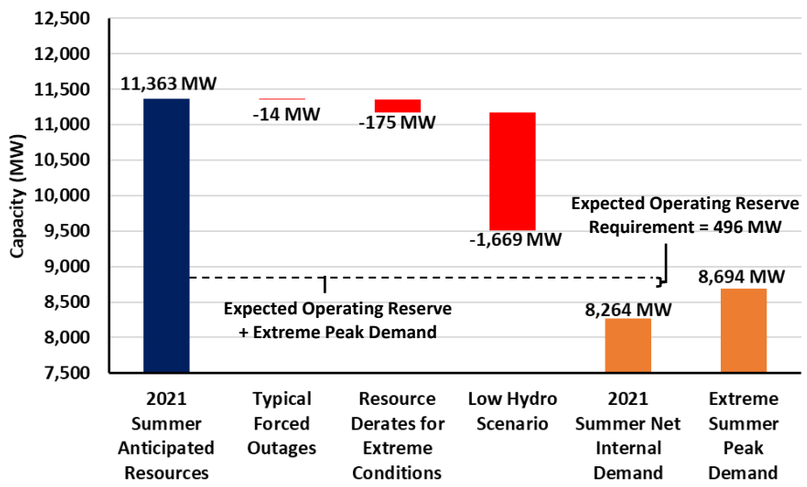
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description

- **Risk Period:** Highest risk for unserved energy at peak demand hour (afternoon)
- **Demand Scenarios:** Net internal demand (50/50) and 90/10 demand forecast
- **Forced Outages:** Average seasonal outages
- **Extreme Derates:** Derate using 90/10 scenario



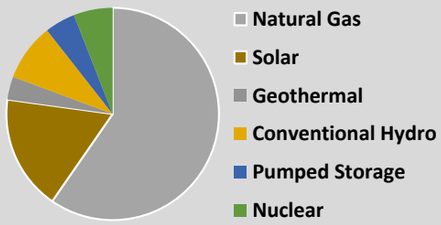
WECC-CAMX

WECC California-Mexico is an assessment area in the WECC RE that includes parts of California, Nevada, and Baja California, Mexico.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members, which include 38 BA, represent a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million people, it is geographically the largest and most diverse of the NERC RE.

WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 Western United States in between.

On-Peak Fuel Mix



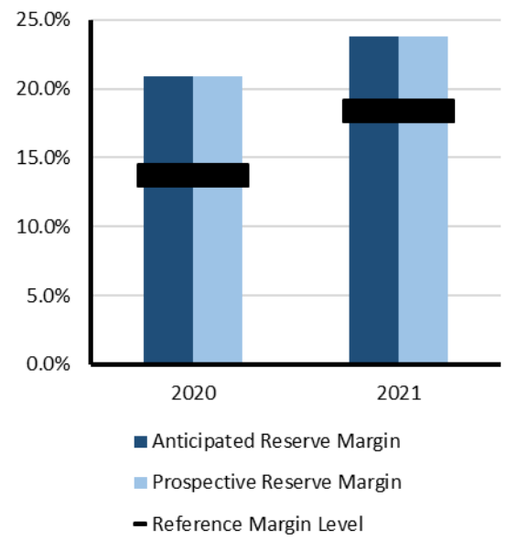
Highlights

- Anticipated resources, which include new capacity in development as well as imports, are expected to be sufficient to meet summer peak demand. However, supply shortfalls from unanticipated low variable generation output, limited imports, or thermal generation outages could lead to energy emergencies. Extreme demand, as seen in 2020, could also lead to emergencies.
- WECC-CAMX has planned resource additions of 1,300 MW over the summer, including 825 MW of new battery storage that are in development. Owners and operators must keep focus on project timelines and implementation milestones to meet anticipated resource levels and help reduce resource adequacy risks in late-summer.
- The Western Interconnection is at risk of experiencing operating challenges from wildfires. Transmission lines may be removed from service in areas with active wildfires or heightened wildfire risk. These transmission outages can impose BPS operational constraints resulting in loss of load events.
- Based on a WECC probabilistic assessment, the California portion of the assessment area has an LOLH of 0.20 hours and an EUE of 10,185 MWh. The Mexico portion has negligible LOLH and EUE.

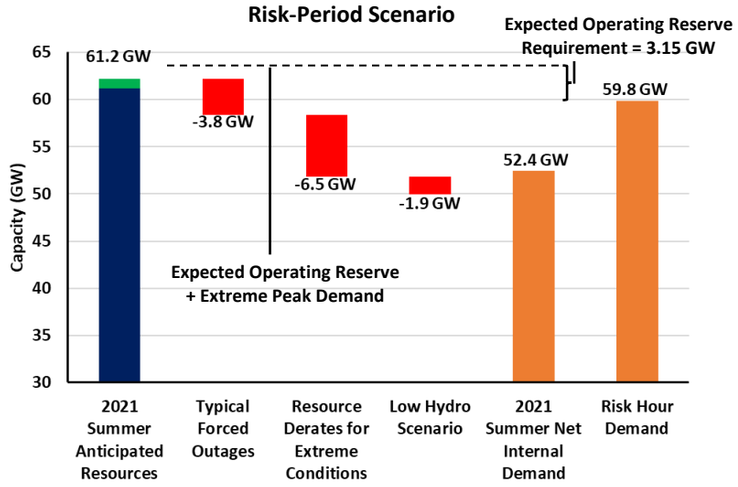
Risk Scenario Summary

Expected resources (including summer additions) meet operating reserve requirements under normal demand scenarios. Above-normal peak load would cause area resource shortages during periods of peak demand and extend into evenings as solar PV output diminishes while demand remains high. High thermal resource outages or reduced availability of imports associated with extreme or wide-area heat events are likely to result in firm load-shed.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description

- **Risk Period:** Period of greatest risk typically within two hours following afternoon peak demand as solar PV output diminishes
- **Demand Scenarios:** Net internal demand (50/50) and 90/10 demand forecast
- **Forced Outages:** Estimated using market forced outage model
- **Extreme Derates:** Derate on natural gas units based on historic data and manufacturer data for temperature performance and outages



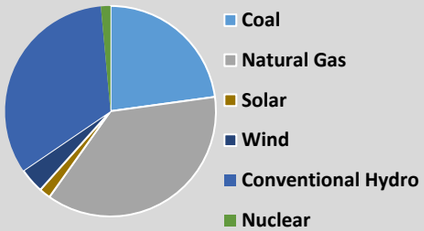
WECC-NWPP & RMRG

WECC Northwest Power Pool and Rocky Mountain Reserve Sharing Group is an assessment area in the WECC RE. The area includes Colorado, Idaho, Montana, Oregon, Utah, Washington, and Wyoming and parts of California, Nebraska, Nevada, and South Dakota.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members, which include 38 BA, represent a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million people, it is geographically the largest and most diverse of the NERC RE.

WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 Western United States in between.

On-Peak Fuel Mix



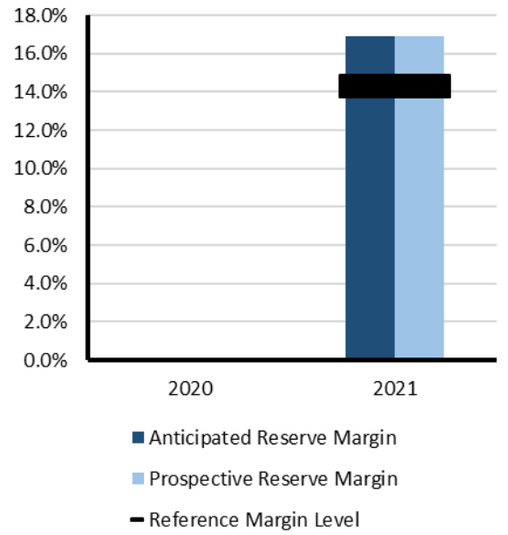
Highlights

- The anticipated reserve margins for WECC, its subregions, and all zones within are expected to exceed their respective NERC Reference Margin Levels for the upcoming season
- WECC merged the NWPP and RMRG assessment areas in late 2020, so an Anticipated Reserve Margin or a Reference Margin Level was not produced for the 2020 assessment year for comparison. However, it is estimated that anticipated resources have declined by 4% since 2020 while demand is not significantly changed in the merged area for the upcoming summer (see **Demand and Resource Tables**).
- Localized short-term operational issues may occur due to wildfires. Due to the widely dispersed nature of the transmission system, outages due to wildfires are generally not widespread.
- Based on a WECC probabilistic assessment, the WECC-NWPP assessment area had an LOLH of 0.06 hour and a EUE of 3,442 MWh.

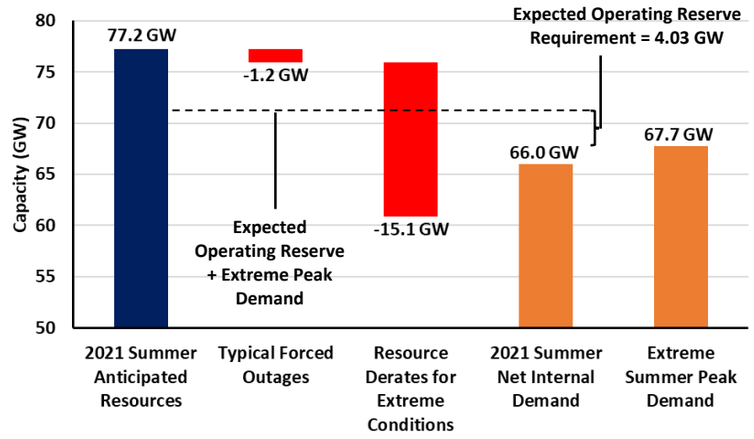
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Extreme summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, and short-term load interruption).

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description

- **Risk Period:** Highest risk for unserved energy at peak demand hour (late afternoon)
- **Demand Scenarios:** Net internal demand (50/50) and 90/10 demand forecast
- **Forced Outages:** Average seasonal outages
- **Extreme Derates:** Derate using 90/10 scenario



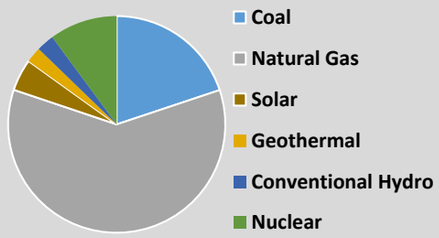
WECC-SRSG

WECC Southwest Reserve Sharing Group is an assessment area in the WECC RE. It includes Arizona and New Mexico and part of California and Texas.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members, which include 38 BA, represent a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million people, it is geographically the largest and most diverse of the NERC RE.

WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 Western United States in between.

On-Peak Fuel Mix



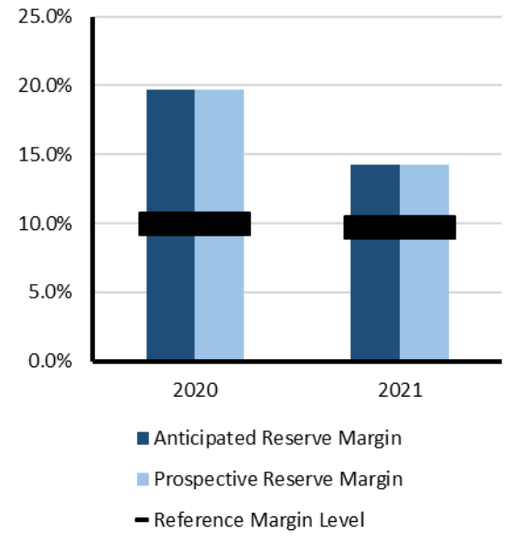
Highlights

- The Anticipated Reserve Margins for WECC, its subregions, and all zones within are expected to exceed their respective NERC Reference Margin Levels for the upcoming season.
- For the upcoming summer season, California ISO is procuring resources to improve reliability risks.
- Localized short-term operational issues may occur due to wildfires. Due to the widely dispersed nature of the transmission system, outages due to wildfires are generally not widespread.
- Based on a WECC probabilistic assessment, the WECC-SRSG assessment area had negligible LOLH and EUE.

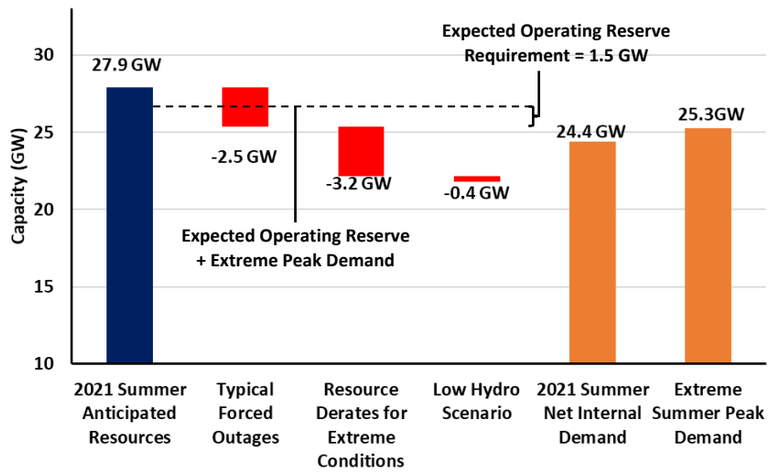
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Extreme summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, and short-term load interruption).

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description

- **Risk Period:** Highest risk for unserved energy at peak demand hour (late afternoon)
- **Demand Scenarios:** Net internal demand (50/50) and 90/10 demand forecast
- **Forced Outages:** Average seasonal outages
- **Extreme Derates:** Derate using 90/10 scenario

Data Concepts and Assumptions

The table below explains data concepts and important assumptions used throughout this assessment.

General Assumptions
• Reliability of the interconnected BPS is comprised of both adequacy and operating reliability:
▪ Adequacy is the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
▪ Operating reliability is the ability of the electric system to withstand sudden disturbances such as electric short-circuits or unanticipated loss of system components.
• The reserve margin calculation is an important industry planning metric used to examine future resource adequacy.
• All data in this assessment is based on existing federal, state, and provincial laws and regulations.
• Differences in data collection periods for each assessment area should be considered when comparing demand and capacity data between year-to-year seasonal assessments.
• *2020 Long-Term Reliability Assessment* data has been used for most of this 2021 assessment period augmented by updated load and capacity data.
• A positive net transfer capability would indicate a net importing assessment area; a negative value would indicate a net exporter.
Demand Assumptions
• Electricity demand projections, or load forecasts, are provided by each assessment area.
• Load forecasts include peak hourly load[18] or total internal demand for the summer and winter of each year.[19]
• Total internal demand projections are based on normal weather (50/50 distribution[20]) and are provided on a coincident[21] basis for most assessment areas.
• Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour.
Resource Assumptions
Resource planning methods vary throughout the North American BPS. NERC uses the categories below to provide a consistent approach for collecting and presenting resource adequacy. **Table 2** below shows the wind and solar generation resources in each assessment area and describes how capacity contributions values are determined.
Anticipated Resources:
• **Existing-Certain Capacity**: Included in this category are commercially operable generating unit or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the summer season: unit must have a firm capability and have a power purchase agreement (PPA) with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or where energy-only markets exist, unit must be a designated market resource eligible to bid into the market.
• **Tier 1 Capacity Additions**: This category includes capacity that either is under construction or has received approved planning requirements.
• **Net Firm Capacity Transfers (Imports minus Exports)**: This category includes transfers with firm contracts.
Prospective Resources: Includes all anticipated resources plus the following:
Existing-Other Capacity: Included in this category are commercially operable generating units or portions of generating units that could be available to serve load for the period of peak demand for the season but do not meet the requirements of existing-certain.
Reserve Margin Descriptions

[18] *Glossary of Terms* used in NERC Reliability Standards

[19] The summer season represents June–September and the winter season represents December–February.

[20] Essentially, this means that there is a 50% probability that actual demand will be higher and a 50% probability that actual demand will be lower than the value provided for a given season/year.

[21] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval; this is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year. SERC and FRCC calculate total internal demand on a noncoincidental basis.

Planning Reserve Margin: This is the primary metric used to measure resource adequacy; it is defined as the difference in resources (anticipated or prospective) and net internal demand then divided by net internal demand and shown as a percentage.

Reference Margin Level: The assumptions and naming convention of this metric vary by assessment area. The Reference Margin Level can be determined using both deterministic and probabilistic (based on a 0.1/year loss of load study) approaches. In both cases, this metric is used by system planners to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing a Reference Margin Level is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increase demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, a Reference Margin Level is established by a state, provincial authority, ISO/RTO, or other regulatory body. In some cases, the Reference Margin Level is a requirement. Reference Margin Levels may be different for the summer and winter seasons. If a Reference Margin Level is not provided by an assessment area, NERC applies 15% for predominately thermal systems and 10% for predominately hydro systems.

Seasonal Risk Scenario Chart Description

Each assessment area performed an operational risk analysis that was used to produce the seasonal risk scenario charts in the **Regional Assessments Dashboards**. The chart presents deterministic scenarios for further analysis of different resource and demand levels: The left blue column shows anticipated resources (from the resource adequacy data table), and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand from the resource adequacy data table and the extreme summer peak demand—both determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources, such as the following:

- Reductions for typical generation outages (i.e., maintenance and forced, not already accounted for in anticipated resources)
- Reductions that represent additional outage or performance derating by resource type for extreme, low-probability conditions (e.g., drought condition impacts on hydroelectric generation, low-wind scenario affecting wind generation, fuel supply limitations, or extreme temperature conditions that result in reduced thermal generation output)
- Additional capacity resources that represent quantified capacity from operational procedures, if any, that are made available during scarcity conditions

Not all assessment areas have the same categories of adjustments to anticipated resources. Furthermore, each assessment area determined the adjustments to capacity based on methods or assumptions that are summarized below the chart. Methods and assumptions differ by assessment area and may not be comparable.

The chart enables evaluation of resource levels against levels of expected operating reserve requirement and the forecasted demand. Further, the effects from low-probability, extreme events can also be examined by comparing resource levels after applying extreme-scenario derates and/or extreme summer peak demand. Because such extreme scenario analysis depicts the cumulative impact resulting from the occurrence of multiple low-probability events, the overall likelihood of this scenario is very low.

Demand and Resource Tables

Peak demand and supply capacity data for each assessment area are provided below.

MISO Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	124,866	122,398	-2.0%
Demand Response: Available	6,172	6,038	-2.2%
Net Internal Demand	118,694	116,360	-2.0%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	140,636	138,464	-1.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	2,795	2,979	6.6%
Anticipated Resources	143,430	141,443	-1.4%
Existing-Other Capacity	290	633	118.1%
Prospective Resources	143,720	146,586	2.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.8%	21.6%	0.8
Prospective Reserve Margin	21.1%	26.0%	4.9
Reference Margin Level	18.0%	18.3%	0.3

MRO-Manitoba Hydro Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	3,272	2,965	-9.4%
Demand Response: Available	0	0	-
Net Internal Demand	3,272	2,965	-9.4%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	5,239	5,173	-1.3%
Tier 1 Planned Capacity	0	186	-
Net Firm Capacity Transfers	-1,526	-1,596	4.6%
Anticipated Resources	3,713	3,763	1.4%
Existing-Other Capacity	125	37	-70.3%
Prospective Resources	3,838	3,800	-1.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	13.5%	26.9%	13.4
Prospective Reserve Margin	17.3%	28.2%	10.9
Reference Margin Level	12.0%	12.0%	0.0

MRO-SaskPower Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	3,480	3,400	-2.3%
Demand Response: Available	60	60	0.0%
Net Internal Demand	3,420	3,340	-2.3%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	3,904	3,863	-1.1%
Tier 1 Planned Capacity	0	14	-
Net Firm Capacity Transfers	125	125	0.0%
Anticipated Resources	4,029	4,002	-0.7%
Existing-Other Capacity	0	0	-
Prospective Resources	4,029	4,002	-0.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	17.8%	19.8%	2.0
Prospective Reserve Margin	17.8%	19.8%	2.0
Reference Margin Level	11.0%	11.0%	0.0

NPCC-Maritimes Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	3,370	3,479	3.2%
Demand Response: Available	369	305	-17.3%
Net Internal Demand	3,001	3,174	5.8%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	5,312	5,448	2.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-53	-57	7.5%
Anticipated Resources	5,259	5,391	2.5%
Existing-Other Capacity	0	0	-
Prospective Resources	5,259	5,391	2.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	75.2%	69.8%	-5.4
Prospective Reserve Margin	75.2%	69.8%	-5.4
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New England Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	25,158	25,244	0.3%
Demand Response: Available	443	434	-2.0%
Net Internal Demand	24,715	24,810	0.4%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	30,791	29,065	-5.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,510	1,208	-20.0%
Anticipated Resources	32,301	30,273	-6.3%
Existing-Other Capacity	324	1,115	244.1%
Prospective Resources	32,625	31,388	-3.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.7%	22.0%	-8.7
Prospective Reserve Margin	32.0%	26.5%	-5.5
Reference Margin Level	18.3%	15.0%	-3.3

NPCC-Ontario Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	22,195	22,500	1.4%
Demand Response: Available	518	621	20.0%
Net Internal Demand	21,677	21,879	0.9%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	25,719	26,217	1.9%
Tier 1 Planned Capacity	49	22	-55.6%
Net Firm Capacity Transfers	0	80	-
Anticipated Resources	25,768	26,319	2.1%
Existing-Other Capacity	0	0	-
Prospective Resources	25,768	26,319	2.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	18.9%	20.3%	1.4
Prospective Reserve Margin	18.9%	20.3%	1.4
Reference Margin Level	14.6%	13.2%	-1.4

NPCC-New York Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	32,296	32,333	0.1%
Demand Response: Available	1,282	1,199	-6.5%
Net Internal Demand	31,014	31,134	0.4%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	38,475	37,805	-1.7%
Tier 1 Planned Capacity	101.2	0	-100.0%
Net Firm Capacity Transfers	1,562	1,816	16.3%
Anticipated Resources	40,138	39,621	-1.3%
Existing-Other Capacity	0	0	-
Prospective Resources	40,138	39,621	-1.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	29.4%	27.3%	-2.1
Prospective Reserve Margin	29.4%	27.3%	-2.1
Reference Margin Level	15.0%	15.0%	0.0

NPCC-Québec Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	21,635	21,436	-0.9%
Demand Response: Available	0	0	-
Net Internal Demand	21,635	21,436	-0.9%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	34,771	33,380	-4.0%
Tier 1 Planned Capacity	14.25	0	-100.0%
Net Firm Capacity Transfers	-1,963	-1,995	1.6%
Anticipated Resources	32,822	31,385	-4.4%
Existing-Other Capacity	0	0	-
Prospective Resources	32,822	31,385	-4.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	51.7%	46.4%	-5.3
Prospective Reserve Margin	51.7%	46.4%	-5.3
Reference Margin Level	9.8%	10.4%	0.6

PJM Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	148,092	149,224	0.8%
Demand Response: Available	8,929	8,779	-1.7%
Net Internal Demand	139,163	140,445	0.9%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	182,523	183,572	0.6%
Tier 1 Planned Capacity	1800	2,400	33.3%
Net Firm Capacity Transfers	1,412	1,460	3.4%
Anticipated Resources	185,735	187,431	0.9%
Existing-Other Capacity	0	0	-
Prospective Resources	185,735	188,891	1.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	33.5%	33.5%	0.0
Prospective Reserve Margin	33.5%	34.5%	1.0
Reference Margin Level	15.5%	14.7%	-0.8

SERC-E Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	43,702	42,680	-2.3%
Demand Response: Available	947	970	2.4%
Net Internal Demand	42,755	41,710	-2.4%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	50,825	50,539	-0.6%
Tier 1 Planned Capacity	88	0	-100.0%
Net Firm Capacity Transfers	266	562	111.3%
Anticipated Resources	51,179	51,101	-0.2%
Existing-Other Capacity	851.5	766	-10.0%
Prospective Resources	52,030	51,867	-0.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	19.7%	22.5%	2.8
Prospective Reserve Margin	21.7%	24.4%	2.7
Reference Margin Level	15.0%	15.0%	0.0

SERC-C Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	40,799	40,341	-1.1%
Demand Response: Available	1,970	1,744	-11.5%
Net Internal Demand	38,829	38,597	-0.6%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	48,368	47,987	-0.8%
Tier 1 Planned Capacity	0	154	-
Net Firm Capacity Transfers	-807	172	-121.3%
Anticipated Resources	47,561	48,314	1.6%
Existing-Other Capacity	4427	4,290	-3.1%
Prospective Resources	51,988	52,604	1.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.5%	25.2%	2.7
Prospective Reserve Margin	33.9%	36.3%	2.4
Reference Margin Level	15.0%	15.0%	0.0

SERC-FP Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	49,286	48,710	-1.2%
Demand Response: Available	2,906	3,030	4.3%
Net Internal Demand	46,380	45,680	-1.5%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	55,093	55,351	0.5%
Tier 1 Planned Capacity	333	0	-100.0%
Net Firm Capacity Transfers	1,146	1,007	-12.1%
Anticipated Resources	56,571	56,358	-0.4%
Existing-Other Capacity	529	0	-100.0%
Prospective Resources	57,100	56,358	-1.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.0%	23.4%	1.4
Prospective Reserve Margin	23.1%	23.4%	0.3
Reference Margin Level	15.0%	15.0%	0.0

SERC-SE Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	47,311	46,631	-1.4%
Demand Response: Available	2,145	1,671	-22.1%
Net Internal Demand	45,166	44,960	-0.5%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	61,495	61,263	-0.4%
Tier 1 Planned Capacity	316	142	-55.0%
Net Firm Capacity Transfers	-972	-1,115	14.7%
Anticipated Resources	60,839	60,290	-0.9%
Existing-Other Capacity	348	783	125.3%
Prospective Resources	61,186	61,073	-0.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	34.7%	34.1%	-0.6
Prospective Reserve Margin	35.5%	35.8%	0.3
Reference Margin Level	15.0%	15.0%	0.0

Texas RE-ERCOT Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	75,200	77,144	2.6%
Demand Response: Available	2,251	2,341	4.0%
Net Internal Demand	72,949	74,803	2.5%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	79,395	80,569	1.5%
Tier 1 Planned Capacity	2172	5,489	152.7%
Net Firm Capacity Transfers	817	210	-74.3%
Anticipated Resources	82,384	86,268	4.7%
Existing-Other Capacity	0	0	-
Prospective Resources	82,412	86,296	4.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	12.9%	15.3%	2.4
Prospective Reserve Margin	13.0%	15.4%	2.4
Reference Margin Level	13.75%	13.75%	0.0

SPP Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	51,943	52,249	0.6%
Demand Response: Available	835	606	-27.4%
Net Internal Demand	51,108	51,643	1.0%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	69,100	66,600	-3.6%
Tier 1 Planned Capacity	0	300	-
Net Firm Capacity Transfers	-1,244	186	-115.0%
Anticipated Resources	67,856	67,086	-1.1%
Existing-Other Capacity	0	0	-
Prospective Resources	67,856	66,539	-1.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	32.8%	29.9%	-2.9
Prospective Reserve Margin	32.8%	28.8%	-4.0
Reference Margin Level	12.0%	16.0%	4.0

WECC-AB Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	11,500	10,886	-5.3%
Demand Response: Available	0	0	-
Net Internal Demand	11,500	10,886	-5.3%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	14,356	12,205	-15.0%
Tier 1 Planned Capacity	0	1,723	-
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	14,356	13,928	-3.0%
Existing-Other Capacity	0	0	-
Prospective Resources	14,356	13,928	-3.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.8%	27.9%	3.1
Prospective Reserve Margin	24.8%	27.9%	3.1
Reference Margin Level	10.4%	9.7%	-0.7

WECC-BC Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	8,278	8,264	-0.2%
Demand Response: Available	0	0	-
Net Internal Demand	8,278	8,264	-0.2%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	11,471	11,178	-2.6%
Tier 1 Planned Capacity	215	185	-13.8%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	11,686	11,363	-2.8%
Existing-Other Capacity	0	0	-
Prospective Resources	11,686	11,363	-2.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	41.2%	37.5%	-3.7
Prospective Reserve Margin	41.2%	37.5%	-3.7
Reference Margin Level	10.4%	9.7%	-0.7

WECC-NWPP-US and RMRG Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	66,532	67,117	0.9%
Demand Response: Available	868	1,087	25.2%
Net Internal Demand	65,664	66,030	0.6%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	78,839	70,069	-11.1%
Tier 1 Planned Capacity	870	1,002	15.2%
Net Firm Capacity Transfers	749	6,139	719.6%
Anticipated Resources	80,457	77,210	-4.0%
Existing-Other Capacity	0	0	-
Prospective Resources	80,457	77,210	-4.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin		16.9%	
Prospective Reserve Margin		16.9%	
Reference Margin Level		14.3%	

WECC-CA/MX Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	53,236	55,409	4.1%
Demand Response: Available	910	922	1.2%
Net Internal Demand	52,326	54,487	4.1%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	63,186	63,396	0.3%
Tier 1 Planned Capacity	92	3,358	3555.6%
Net Firm Capacity Transfers	0	686	-
Anticipated Resources	63,278	67,440	6.6%
Existing-Other Capacity	0	0	-
Prospective Resources	63,278	67,440	6.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.9%	23.8%	2.9
Prospective Reserve Margin	20.9%	23.8%	2.9
Reference Margin Level	13.7%	18.4%	4.7

WECC-SRSG Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	25,145	24,751	-1.6%
Demand Response: Available	144	332	129.9%
Net Internal Demand	25,001	24,419	-2.3%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	29,440	26,850	-8.8%
Tier 1 Planned Capacity	477	188	-60.6%
Net Firm Capacity Transfers	0	866	-
Anticipated Resources	29,917	27,904	-6.7%
Existing-Other Capacity	0	0	-
Prospective Resources	29,917	27,904	-6.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	19.7%	14.3%	-5.4
Prospective Reserve Margin	19.7%	14.3%	-5.4
Reference Margin Level	10.0%	9.8%	-0.2

Variable Energy Resource Contributions

Because electrical output of variable energy resources (e.g., wind, solar) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity. The table below shows the capacity contribution of existing wind and solar resources for each assessment area.

BPS Variable Generation Resources by Assessment Area									
	Wind			Solar			Hydro		
Assessment Area / Interconnection	Nameplate Wind	Expected Wind	Expected Share of Nameplate (%)	Nameplate Solar	Expected Solar	Expected Share of Nameplate (%)	Nameplate Hydro	Expected Hydro	Expected Share of Nameplate (%)
MISO	26,829	3,872	14%	725	469	65%	2,440	2,361	97%
MRO-Manitoba Hydro	259	43	17%	-	-	-	5,461	4,903	90%
MRO-SaskPower	616	66	11%	-	-	-	864	787	91%
NPCC-Maritimes	1,188	287	24%	4	-	0%	1,318	1,186	90%
NPCC-New England	1,505	166	11%	375	112	30%	3,890	2,736	70%
NPCC-New York	2,211	502	23%	57	32	56%	6,725	4,666	69%
NPCC-Ontario	4,946	678	14%	478	66	14%	9,060	5,305	59%
NPCC-Québec	3,880		0%	10		0%	41,339	32,750	79%
PJM	8,790	1,410	16%	2,421	997	41%	3,057	3,057	100%
SERC-C	964	958	99%	521	336	65%	5,005	3,572	71%
SERC-E	-	-	-	649	641	99%	3,131	3,085	99%
SERC-FP	-	-	-	3,624	2,049	57%	-	-	-
SERC-SE	-	-	-	2,735	2,282	83%	3,242	3,288	101%
SPP	26,885	4,670	17%	275	252	92%	5,441	5,130	94%
Texas RE-ERCOT	31,829	8,565	27%	7,608	6,086	80%	556	474	85%
WECC-AB	2,219	162	7%	314	202	64%	894	378	42%

BPS Variable Generation Resources by Assessment Area									
	Wind			Solar			Hydro		
Assessment Area / Interconnection	Nameplate Wind	Expected Wind	Expected Share of Nameplate (%)	Nameplate Solar	Expected Solar	Expected Share of Nameplate (%)	Nameplate Hydro	Expected Hydro	Expected Share of Nameplate (%)
WECC-BC	717	142	20%	2	1	50%	16,334	10,088	62%
WECC-CAMX	7,686	1,089	14%	16,918	10,442	62%	11,821	5,993	51%
WECC-NWPP-US-RMRG	16,180	2,318	14%	5,234	4,028	77%	40,992	20,986	51%
WECC-NWPP-SRSG	3,141	636	20%	1,797	1,265	70%	1,303	558	43%
EASTERN INTERCONNECTION	69,446	12,378	18%	9,005	5,463	61%	49,185	39,183	80%
QUÉBEC INTERCONNECTION	3,880	-	0%	10	-	0%	41,339	32,750	79%
TEXAS INTERCONNECTION	31,829	8,565	27%	7,608	6,086	80%	556	474	85%
WECC INTERCONNECTION	29,943	4,347	15%	24,256	15,938	66%	71,344	38,003	53%
TOTAL-NERC	**135,097**	**25,290**	**19%**	**40,887**	**27,488**	**67%**	**162,425**	**110,410**	**68%**

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2022 Summer Reliability Assessment

May 2022



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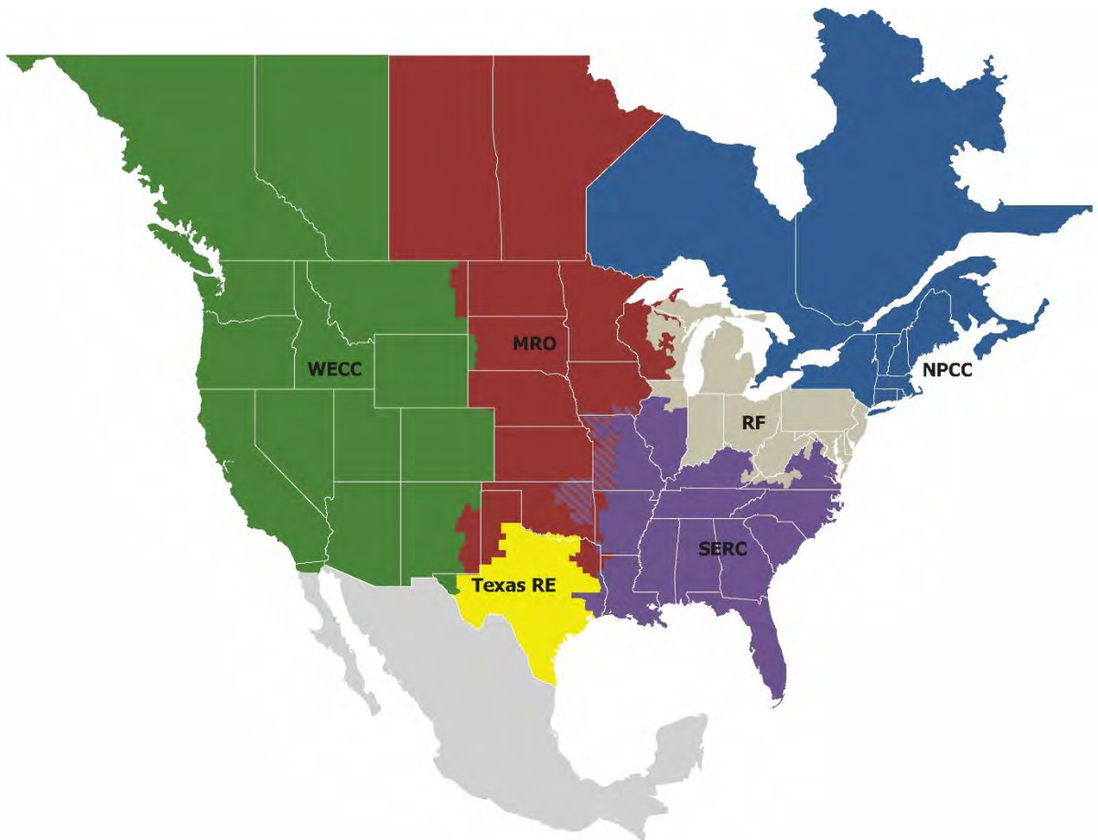
Preface

The vision for the Electric Reliability Organization Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities, is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entities boundaries as shown in the map below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entities while associated Transmission Owners/Operators participate in another. Refer to the **Data Concepts and Assumptions** section for more information. A map and list of the assessment areas can be found in the **Regional Assessments Dashboards** section.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

About this Assessment

NERC's *2022 Summer Reliability Assessment* (*SRA*) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming summer season. In addition, the *SRA* presents peak electricity demand and supply changes as well as highlights any unique regional challenges or expected conditions that might impact the BPS. The reliability assessment process is a coordinated reliability evaluation between the NERC Reliability Assessment Subcommittee, the Regional Entities, and NERC staff with demand and resource projections obtained from the assessment areas. This report reflects NERC and the ERO Enterprise's independent assessment and is intended to inform industry leaders, planners, operators, and regulatory bodies so that they are better prepared to take necessary actions to ensure BPS reliability. This report also provides an opportunity for the industry to discuss plans and preparations to ensure reliability for the upcoming summer period.

Key Findings

NERC's annual SRA covers the upcoming four-month (June–September) summer period. This assessment provides an evaluation of generation resource and transmission system adequacy and energy sufficiency to meet projected summer peak demands and operating reserves. This assessment identifies potential reliability issues of interest and regional topics of concern. While the scope of this seasonal assessment is focused on the upcoming summer, the key findings are consistent with risks and issues that NERC has highlighted in the *2021 Long-Term Reliability Assessment* and other earlier reliability assessments and reports.

The following findings are NERC and the ERO Enterprise's independent evaluation of electricity generation and transmission capacity and potential operational concerns that may need to be addressed for the 2022 summer:

Summer Resource Adequacy Assessment and Energy Risk Analysis

- **Midcontinent ISO (MISO) faces a capacity shortfall in its North and Central areas, resulting in high risk of energy emergencies during peak summer conditions.** Capacity shortfall projections reported in the *2021 LTRA* and as far back as the *2018 LTRA* have continued. Load serving entities in 4 of 11 zones entered the annual planning resource auction (PRA) in April 2022 without enough owned or contracted capacity to cover their requirements. Across MISO, peak demand projections have increased by 1.7% since last summer due in part to a return to normal demand patterns that have been altered in prior years by the pandemic. However, more impactful is the drop in capacity in the most recent PRA: MISO will have 3,200 MW (2.3%) less generation capacity than in the summer of 2021. System operators in MISO are more likely to need operating mitigations, such as load modifying resources or non-firm imports, to meet reserve requirements under normal peak summer conditions. More extreme temperatures, higher generation outages, or low wind conditions expose the MISO North and Central areas to higher risk of temporary operator-initiated load shedding to maintain system reliability.
- **At the start of the summer, a key transmission line connecting MISO's northern and southern areas will be out of service.** Restoration continues on a 4-mile section of 500 kV transmission line that was damaged by a tornado during severe storms on December 10, 2021. The transmission outage affects 1,000 MW of firm transfers between the Midwestern and Southern MISO system that includes parts of Arkansas, Louisiana, and Mississippi. The transmission line is expected to be restored at the end of June 2022.
- **Anticipated resource capacity in Saskatchewan will be strained to meet peak demand projections, which have risen by over 7.5% since 2021.** SaskPower is projected to remain above their planning reserve margin threshold and have sufficient operating reserves for normal peak conditions. However, external assistance is expected to be needed in extreme conditions that cause above-normal generator outages or demand.
- **Drought conditions create heightened reliability risk for the summer.** Drought exists or threatens wide areas of North America, resulting in unique challenges to area electricity supplies and potential impacts on demand:
  - **Energy output from hydro generators throughout most of the Western United States is being affected by widespread drought and below-normal snowpack.** Dry hydrological conditions threaten the availability of hydroelectricity for transfers throughout the Western Interconnection. Some assessment areas, including WECC's California-Mexico (CA/MX) and Southwest Reserve Sharing Group (SRSG), depend on substantial electricity imports to meet demand on hot summer evenings and other times when variable energy resource (e.g., wind, solar) output is diminishing. In the event of wide-area extreme heat event, all U.S. assessment areas in the Western Interconnection are at risk of energy emergencies due to the limited supply of electricity available for transfer.
  - **Extreme drought across much of Texas can produce weather conditions that are favorable to prolonged, wide-area heat events and extreme peak electricity demand.** Resource additions to the ERCOT system in recent years—predominantly solar and some wind—have raised Anticipated Reserve Margins above Reference Margin Levels and ease concerns of capacity shortfalls for normal peak demand. However, extreme heat increases peak demand and can be accompanied by weather patterns that lead to increased forced outages or reduced energy output from resources of all types. A combination of extreme peak demand, low wind, and high outage rates from thermal generators could require system operators to use emergency procedures, up to and including temporary manual load shedding.
  - **As drought conditions continue over the Missouri River Basin, output from thermal generators that use the Missouri River for cooling in Southwest Power Pool (SPP) may be affected in summer months.** Low water levels in the river can impact generators with once-through cooling and lead to reduced output capacity. Energy output from hydro generators on the river can also be affected by drought conservation measures implemented in the reservoir system. Outages and reduced output from thermal and hydro generation could lead to energy shortfalls at peak demand. Periods of above normal wind generator output may give some relief, however, this energy is not assured. System operators could require emergency procedures to meet peak demand during periods of high generator unavailability.

- **All other areas have sufficient resources to manage normal summer peak demand and are at low risk of energy shortfalls from more extreme demand or generation outage conditions.** Anticipated Reserve Margins meet or surpass the Reference Margin Level, indicating that planned resources in these areas are adequate to manage the risk of a capacity deficiency under normal conditions. Furthermore, based on risk scenario analysis in these areas, resources and energy appear adequate.

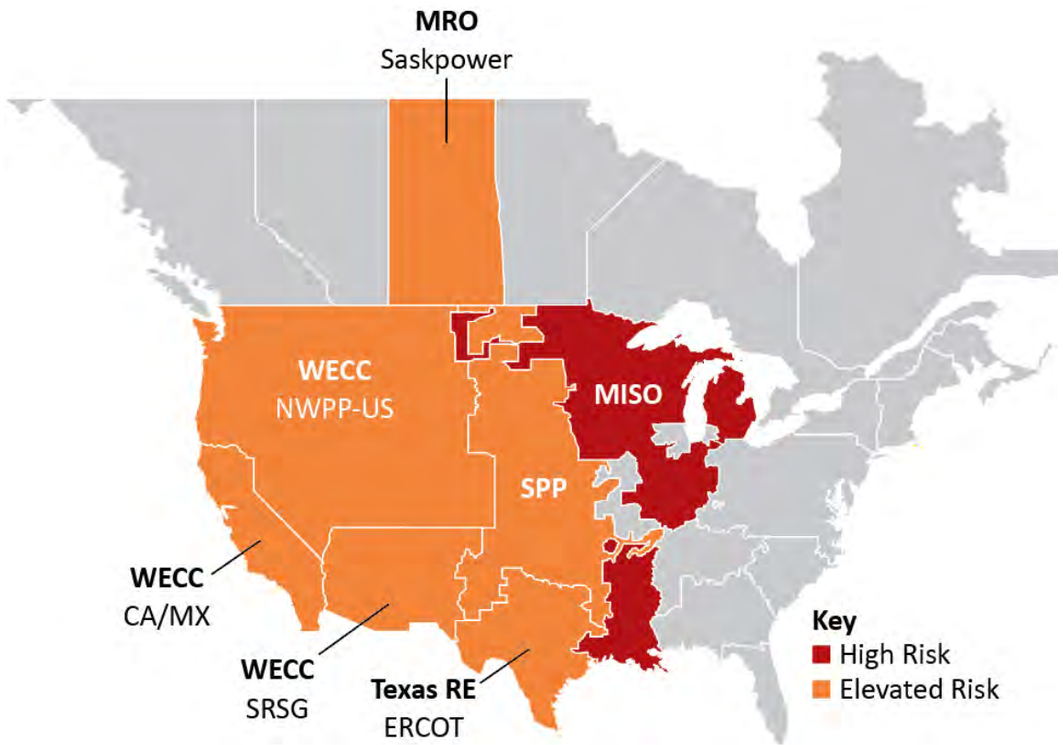


Figure 1: Summer Reliability Risk Area Summary

Seasonal Risk Assessment Summary	
High	Potential for insufficient operating reserves in normal peak conditions
Elevated	Potential for insufficient operating reserves in above-normal conditions
Low	Sufficient operating reserves expected

Other Reliability Issues for Summer

- **Supply chain issues and commissioning challenges on new resource and transmission projects are a concern in areas where completion is needed for reliability during summer peak periods.** Assessment areas report that some generation and transmission projects are being impacted by product unavailability, shipping delays, and labor shortages. At the time of this assessment publication, WECC-CA/MX, and WECC-SRSG have sizeable amounts of generation capacity in development and included in their resource projections for summer. In Texas (ERCOT), transmission expansion projects are underway to alleviate transmission constraints and maintain system stability as the BPS is adapted to rapid growth in new generation; delays or cancellations of transmission projects can cause transmission system congestion during peak conditions and affect the ability to serve load in localized areas. Should project delays emerge, affected Generator Owners (GOs) and Transmission Owners must communicate changes to Balancing Authorities (BAs), Transmission Operators, and Reliability Coordinators, so that impacts are understood and steps are taken to reduce risks of capacity deficiencies or energy shortfalls.

- **Coal-fired GOs are having difficulty obtaining fuel and non-fuel consumables as supply chains are stressed.** No specific BPS reliability impacts are currently foreseen; however, coal stockpiles at power plants are relatively low compared to historical levels. Some owners and operators report challenges in arranging replenishment due to mine closures, rail shipping limitations, and increased coal exports. Some GOs have implemented controls to maintain sufficient stocks for peak months while BAs and Reliability Coordinators are continuing to conduct fuel surveys and monitoring the situation.

- **The electricity and other critical infrastructure sectors face cyber security threats from Russia and other potential actors amid heightened geopolitical tensions in addition to ongoing cyber risks.** Russian attackers may be planning or attempting malicious cyber activity to gain access and disrupt the electric grid in North America in retaliation for support to Ukraine. The Electricity Infrastructure Sharing and Analysis Center (E-ISAC) continues to exchange information with its members and has posted communications and guidance from government partners and other advisories on its Portal. E-ISAC members are encouraged to check in regularly to receive updates and to actively share information regarding threats and other malicious activities with the E-ISAC to enable broader communication with other sector participants and government partners.

- **Unexpected tripping of solar photovoltaic (PV) resources during grid disturbances continues to be a reliability concern.** In May and June 2021, the Texas Interconnection experienced widespread solar PV loss events like those previously observed in the California area. Similarly, four additional solar PV loss events occurred between June and August 2021 in California.

- During these events, widespread loss of solar PV resources was also coupled with the loss of synchronous generation, unintended interactions with remedial action schemes, and some tripping of distributed energy resources. As industry urgently takes steps to address systemic reliability issues through modeling, planning, and interconnection processes, system operators in areas with significant amounts of solar PV resources should be aware of the potential for resource loss events during grid disturbances.
- **An active late-summer wildfire season in the Western United States and Canada is anticipated, posing BPS reliability risks.** Government agencies warn of the potential for above-normal wildfire risk beginning in June across much of Canada, in the U.S. South Central states, and Northern California. If drought conditions persist, the fire outlook for late summer would likely extend across the Western half of North America. The interconnected transmission system can be impacted in areas where wildfires are active as well as areas where there is heightened risk of wildfire ignition due to dry weather and ground conditions. In addition, smoke from wildfires can cause diminished output from solar PV resources, and electricity supply will be affected by lower output from BPS-connected solar PV resources. Conversely, system demand may increase as part of distribution demand served by rooftop solar PV is less in smoky conditions.

ERO Actions to Reduce Risks of Unexpected Solar PV Tripping

Industry experience with unexpected tripping of BPS-connected solar PV generation units can be traced back to the 2016 Blue Cut fire in California, and similar events have occurred as recently as Summer 2021. A common thread with these events is the lack of inverter-based resource (IBR) ride-through capability causing a minor system disturbance to become a major disturbance. The latest disturbance report reinforces that improvements to NERC Reliability Standards are needed to address systemic issues with IBRs. At a high level, these include the following:

- **Performance-Based Requirements:** A number of NERC Reliability Standards require documentation that demonstrates compliance with the requirement (i.e., PRC-024-3); however, they do not specify a certain degree of performance that must be met. NERC has initiated action against this issue by developing a standards authorization request and strongly recommends that PRC-024 be retired and replaced with a comprehensive ride-through standard that focuses specifically on the generator protections and controls.
- **Performance Validation Requirement:** NERC has initiated action against this issue by developing a reliability guideline on interconnection requirements as well as issuing recommendations from recent disturbance reports. NERC strongly recommends that a performance validation standard be developed that ensures that Reliability Coordinators, Transmission Operators, or BAs are assessing the performance of interconnected facilities during grid disturbances, identifying any abnormalities, and executing corrective actions with affected facility owners to eliminate these issues. This requires entities to have strong interconnection requirements as NERC highlights in its reliability guidelines and disturbance reports.
- **Electromagnetic Transient Modeling and Model Quality Assurance:** NERC has initiated action against this issue by issuing recommendations in recent disturbance reports and strongly recommends that electromagnetic transient (EMT) modeling and studies be incorporated into NERC Reliability Standards to ensure that adequate reliability studies are conducted to ensure reliable operation of the BPS moving forward. Existing positive sequence simulation platforms have limitations in their ability to identify possible performance issues, many of which can be identified using EMT modeling and studies. As the penetration of IBRs continues to grow across North America, the need for EMT modeling and studies will only grow exponentially. Furthermore, NERC Reliability Standards need enhancements to ensure that model accuracy and model quality checks are explicitly defined.

Summer Temperature and Drought Forecasts

Peak electricity demand in most areas is directly influenced by temperature. Weather officials are expecting above normal temperatures for much of North America this summer (see **Figure 2**). In addition, drought exists or threatens wide areas of North America, resulting in unique challenges to area electricity supplies and potential impacts on demand.[1] Assessment area load forecasts account for many years of historical demand data, often up to 30 years, to predict summer peak demand and prepare for more extreme conditions. Above average seasonal temperatures can contribute to high peak demand as well as increases in forced outages for generation and some BPS equipment. Effective preseason maintenance and preparations are particularly important to BPS reliability in severe or prolonged periods of above-normal temperatures.

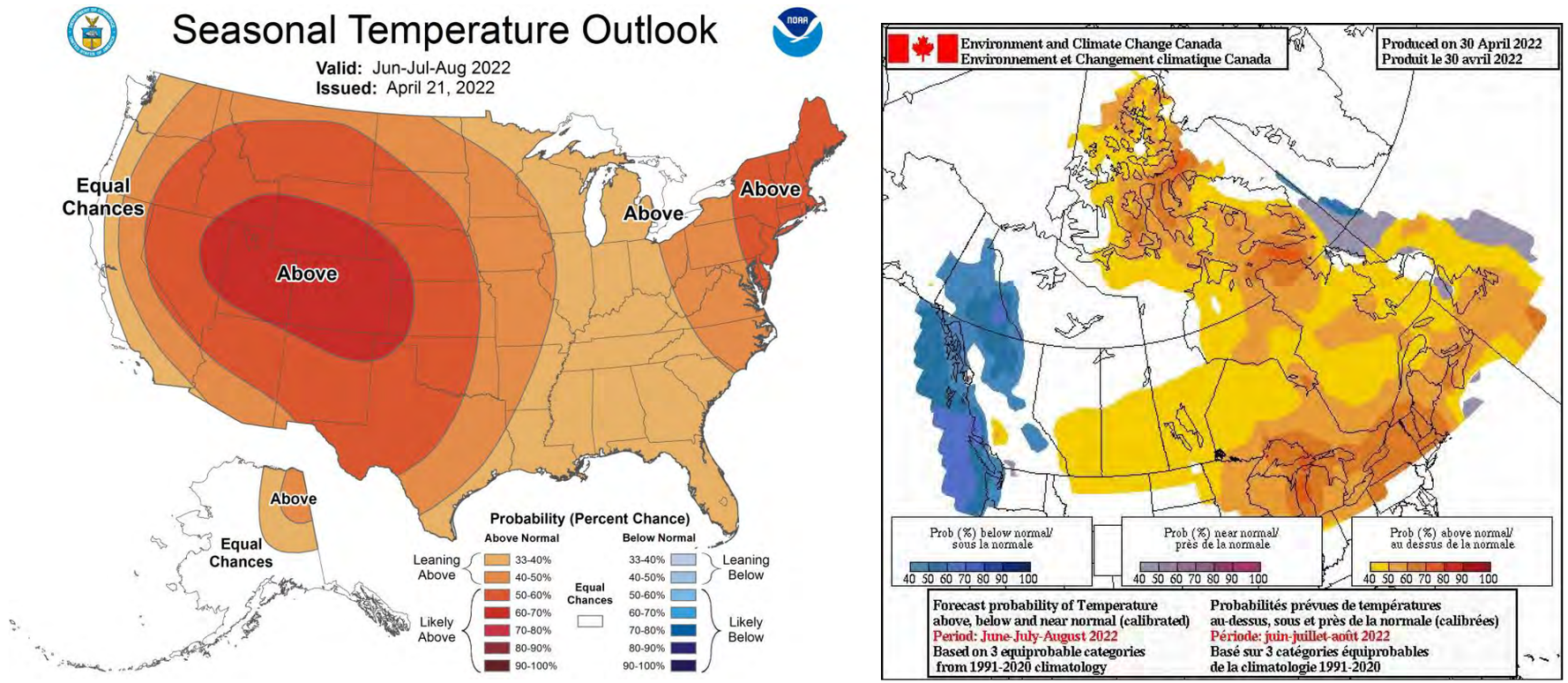


Figure 2: United States and Canada Summer Temperature Outlook[2]

[1] See North American Drought Monitor: https://www.ncdc.noaa.gov/temp-and-precip/drought/nadm/maps

[2] Seasonal forecasts obtained from U.S. National Weather Service and Natural Resources Canada: https://www.cpc.ncep.noaa.gov/products/predictions/long_range/ and https://weather.gc.ca/saisons/prob_e.html

Wildfire Risk Potential and BPS Impacts

Above-normal fire risk at the beginning of the summer exists in much of Canada as well as in the U.S. South Central states, Northern California, and Oregon, setting the stage for an active fire season at the beginning of the summer (see **Figure 3**). In late summer, hotter and drier conditions are expected to cause elevated fire risk in California and the U.S. West Coast. BPS operation can be impacted in areas where wildfires are active as well as areas where there is heightened risk of wildfire ignition due to weather and ground conditions.

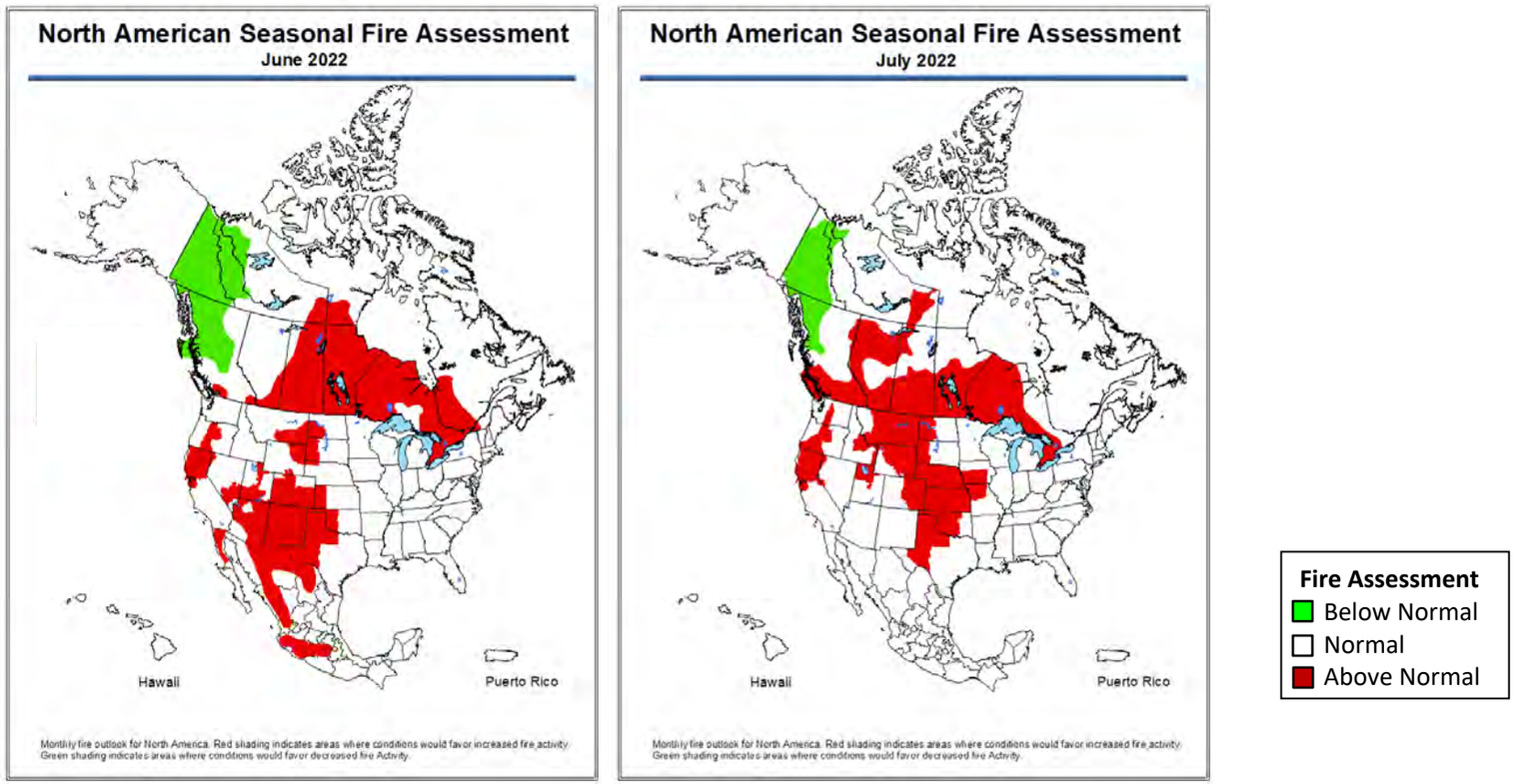


Figure 3: North American Seasonal Fire Assessment for June and July 2022[3]

Wildfire prevention planning in California and other areas includes power shut-off programs in high fire-risk areas. When conditions warrant implementing these plans, power lines (including transmission-level lines) may be preemptively de-energized in high fire-risk areas to prevent wildfire ignitions. Other wildfire risk mitigation activities include implementing enhanced vegetation management, equipment inspections, system hardening, and added situational awareness measures. In January 2021, the ERO published the *Wildfire Mitigation Reference Guide*[4] to promote preparedness within the North American electricity power industry and share the experience and practices from utilities in the Western Interconnection.

[3] *See North American Seasonal Fire Assessment and Outlook*, April 2022: https://www.predictiveservices.nifc.gov/outlooks/NA_Outlook.pdf

[4] See the NERC *Wildfire Mitigation Reference Guide*, January 2021: https://nerc.com/comm/RSTC/Documents/Wildfire%20Mitigation%20Reference%20Guide_January_2021.pdf

Risk Discussion

WECC: Western Interconnection

An elevated risk of energy emergencies persists across the U.S. Western Interconnection this summer as dry hydrological conditions threaten the availability of hydroelectric energy for transfer. Periods of high demand over a wide area will result in reduced supplies of energy for transfer, causing operators to rely primarily on alternative resources for system balancing, including natural-gas-fired generators and battery systems.

Throughout the Western Interconnection, BAs rely on flexible resources to support balancing the increasingly weather-dependent load with the variable energy generation within the resource mix. Dispatchable generation from hydroelectric and thermal plants internal to the BA's area as well as imports of surplus energy in another area are called upon by operators when area shortfalls are anticipated. Under normal conditions, there is sufficient energy and resource capacity and an adequate transmission network for transfers between areas to meet system ramping needs. However, conditions like wide-area heat events can reduce the availability of resources for transfer as areas serve higher internal demands. Additionally, transmission networks can become stressed when events like wildfires or wide-area heatwaves cause network congestion. The growing reliance on transfers within the Western Interconnection and falling resource capacity in many adjacent areas increases the risk that extreme events will lead to load interruption.

Recent Heatwave Events in the Western Interconnection

From August 14 through August 19, 2020, the Western United States suffered an intense and prolonged heatwave that affected many areas across the Western Interconnection.[5] Because of above-average temperatures, generation and transmission capacity struggled to keep up with increased electricity demand. Throughout many supply-constrained hours over this same period, generation resource output was below preseason peak forecasts for nearly all resource types, including natural gas, wind, solar, and hydroelectric. During the event, 10 Western Interconnection BAs issued 18 separate energy emergency alerts (EEA). The impacts of the August heatwave struck the entirety of the Western Interconnection and caused a peak demand record of 162,017 MW on August 18, 2020, at 4:00 p.m. Mountain time. Although demand peaked on August 18, the most severe reliability consequence of the heatwave event occurred at the beginning, when 1,087 MW of firm load was shed on August 14 and 692 MW was shed on August 15 in California. System operators at the California ISO initiated rotating electricity outages to reduce demand during early evening hours so that operating reserves would be sufficient to prevent even greater consequences for the system.

The West experienced another wide-area extreme temperature event in 2021. From late-June through mid-July, high temperatures extended over a broad area that included Northern California, Idaho, Western Nevada, Oregon, and Washington state in the United States as well as in British Columbia and (in its latter phase) Alberta, Manitoba, the Northwest Territories, Saskatchewan, and Yukon areas in Canada. Temperatures reached 121 degrees Fahrenheit in some areas, and peak demand records were set in British Columbia and Alberta. BAs in California, the U.S. Northwest, and the Canadian province of Saskatchewan issued EEAs.

In summer, WECC's CA/MX, the Northwest Power Pool (NWPP), and SRSG assessment areas can be exposed to greater risk of resource shortfalls for the hours that immediately follow afternoon peak demand. The reason the risk is greater in these hours is that solar resource output is diminishing with the setting sun while demand is still near its daily high. The scenarios for all three areas shown in **Figure 4** illustrate (six charts) how the need for imports changes from the peak demand hour to the higher risk hours that follow; see the **Data Concepts and Assumptions** for more information about these charts. Anticipated resources in the high risk hours are lower than the on peak hours due to reduced solar PV output. During periods of peak demand and normal forced outages, anticipated resources in each assessment area provide the needed energy to ensure demand and operating reserve requirements are met. Demand or resource derates from extreme conditions that cannot be remedied with imports will result in energy emergencies and the potential for load shedding. In prior summers, only CA/MX had greatest risk exposure in hours after peak demand; off-peak risk has increased in other parts of the Western Interconnection this year.

[5] WECC August Heat Wave Event information: WECC's *August Heat Wave Analysis* Presentation

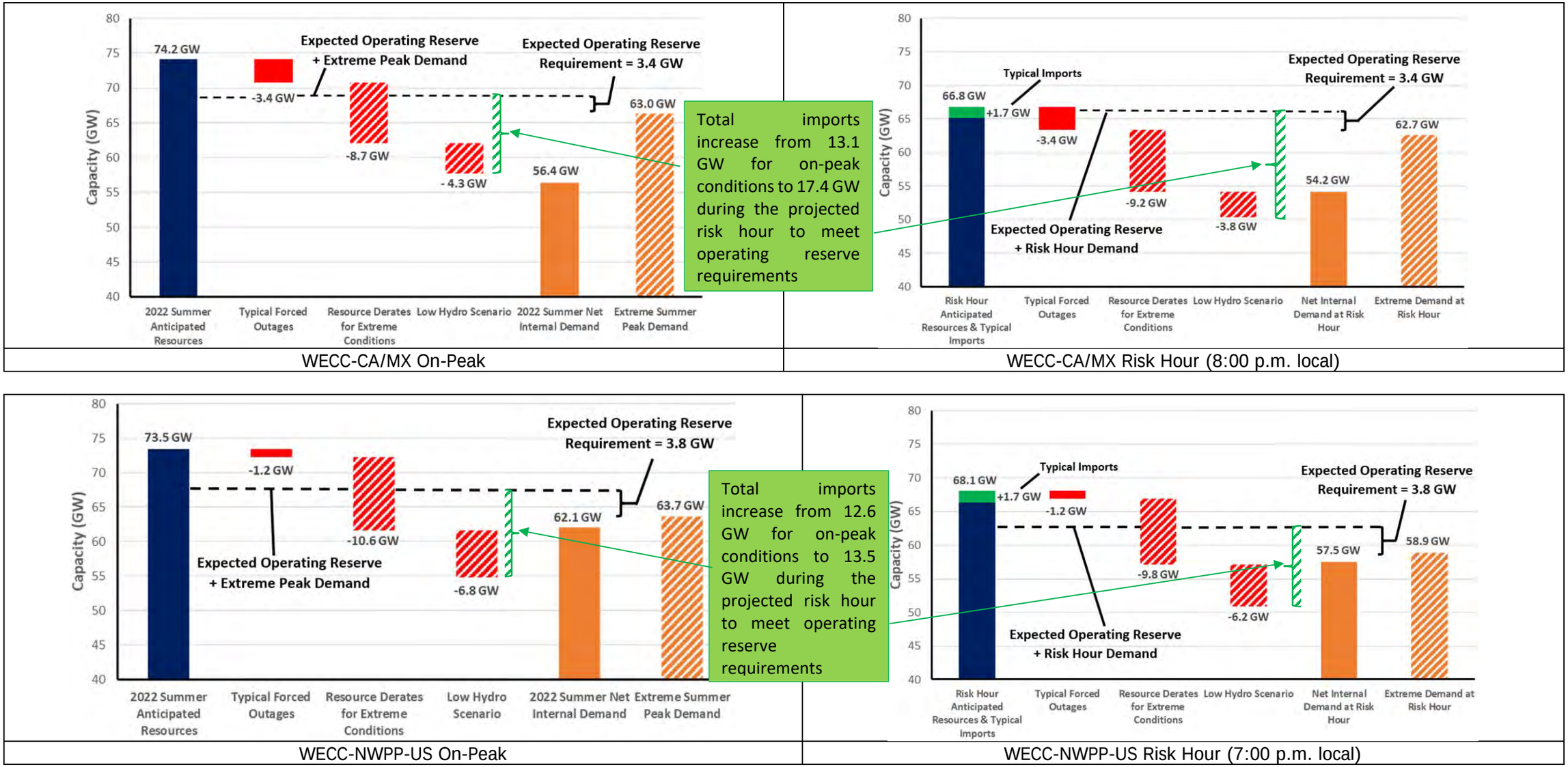
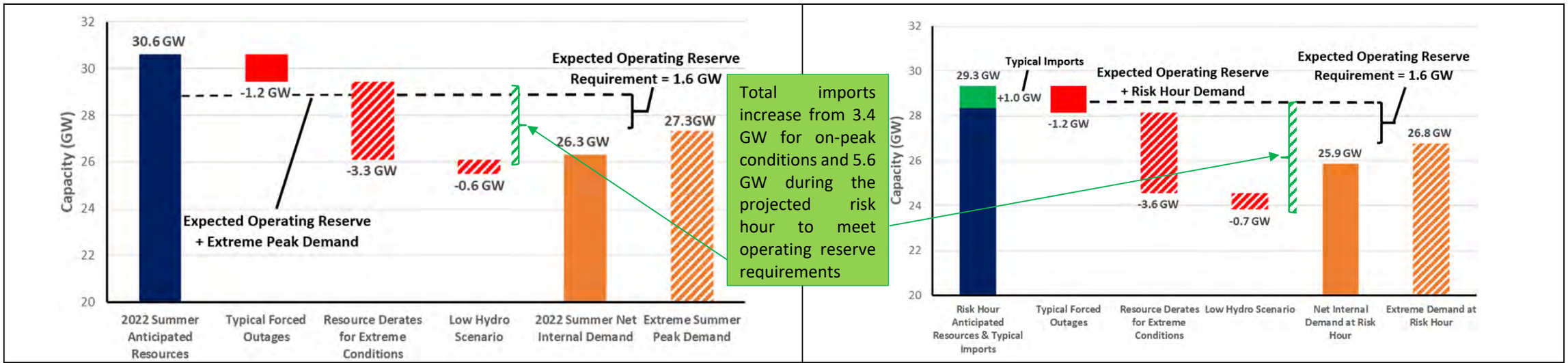


Figure 4: Risk Scenarios for WECC U.S. Assessment Areas



WECC-SRSG On-Peak | WECC-SRSG Risk Hour (7:00 p.m. local)

Figure 4 (continued): Risk Scenarios for WECC U.S. Assessment Areas

WECC performed probabilistic studies and identified a continued risk of energy shortfalls for the WECC-CA/MX area. Their analysis models expected demand and resource contribution over all hours and accounts for variability with historical distributions. Assuming that the nearly 3.4 GW of new resource additions come into service in California for the summer, the Loss-of-Load Hours (LOLH) metric of projected hours with insufficient resources to meet planning reserve criteria will be one hour for the California portion. In a scenario without the new resource additions, the LOLH increases to four hours. Expected unserved energy (EUE) in California for these two scenarios is 4 MWh and 8,755 MWh, respectively. In the Mexico portion of CA/MX, LOLH of 10 and 14 hours and EUE of 100 and 200 MWh, respectively, are projected. All other WECC assessment areas have negligible load-loss and unserved energy for the summer. WECC's probabilistic study modeling includes non-firm transfers between WECC assessment areas and provides a wide-area assessment of resource adequacy. The WECC studies show that, as more areas experience the same high-demand conditions during wide-area heat events, the supply of electricity for transfer across the Interconnection is reduced and the risk of unserved energy increases.

Risk Assessments of Resource and Demand Scenarios

Seasonal risk scenarios for each assessment area are presented in the **Regional Assessments Dashboards** section. The on-peak reserve margins and seasonal risk scenario chart in each dashboard provide potential summer peak demand and resource condition information. The reserve margins on the right side of the dashboard pages provide a comparison to the previous year's assessment. The seasonal risk scenario charts present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. The assessment areas determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below the seasonal risk scenario charts; see the **Data Concepts and Assumptions** for more information about this chart.

The seasonal risk scenario charts can be expressed in terms of reserve margins. In **Table 1**, each assessment area's Anticipated Reserve Margins are shown alongside the reserve margins for a typical generation outage scenario (where applicable) and the extreme demand and resource conditions in their seasonal risk scenario. Highlighted areas are identified as having resource adequacy or energy risks for the summer in the key findings discussion. The typical outages reserve margin is comprised of anticipated resources minus the capacity that is likely to be in maintenance or forced outage at peak demand. If the typical maintenance or forced outage margin is the same as the anticipated reserve margin, it is because an assessment area has already factored typical outages into the anticipated resources. The extreme conditions

margin includes all components of the scenario and represents the most severe operating conditions of an area's scenario. Note that any reserve margin below zero indicates that the resources fall below demand in the scenario.

Extreme generation outages, low resource output, and peak loads similar to those experienced in August 2020 are reliability risks in certain areas for the upcoming summer. When forecasted resources fall below expected demand, grid operators would need to employ operating mitigations or EEAs to obtain the capacity and energy necessary to meet extreme peak demands. Table 2 describes the various EEA levels and the circumstances for each.

Table 2: Energy Emergency Alert Levels

EEA Level	Description	Circumstances
EEA 1	All available generation resources in use	The BA is experiencing conditions where all available generation resources are committed to meet firm load, firm transactions, and reserve commitments and is concerned about sustaining its required contingency reserves. Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
EEA 2	Load management procedures in effect	The BA is no longer able to provide its expected energy requirements and is an energy deficient BA. An energy deficient BA has implemented its operating plan(s) to mitigate emergencies. An energy deficient BA is still able to maintain minimum contingency reserve requirements.
EEA 3	Firm Load interruption is imminent or in progress	The energy deficient BA is unable to meet minimum contingency reserve requirements.

Table 1: Seasonal Risk Scenario On-Peak Reserve Margins

Assessment Area	Anticipated Reserve Margin	Anticipated Reserve Margin with Typical Outages	Anticipated Reserve Margin with Higher Demand, Outages, Derates in Extreme Conditions
MISO	21.1%	3.2%	-8.3%
MRO-Manitoba	27.3%	21.5%	7.8%
MRO-SaskPower	12.2%	2.6%	-5.3%
NPCC-Maritimes	39.2%	28.7%	11.7%
NPCC-New England	20.6%	9.3%	-2.5%[6]
NPCC-New York	30.4%	22.4%	13.5%
NPCC-Ontario	18.0%	18.0%	3.0%
NPCC-Québec	40.3%	40.3%	35.0%
PJM	31.7%	23.9%	16.1%
SERC-Central	18.3%	10.7%	3.3%
SERC-East	21.4%	18.3%	11.3%
SERC-Florida Peninsula	20.7%	17.3%	15.1%
SERC-Southeast	29.8%	25.4%	17.4%
SPP	30.6%	12.3%	-4.7%
Texas RE-ERCOT	22.0%	15.9%	1.1%
WECC-NWPP-AB	19.7%	17.2%	5.3%
WECC-NWPP-BC	39.3%	39.1%	10.4%
WECC-CA/MX	31.5%	25.4%	-13.1%
WECC-NWPP-US	18.3%	16.3%	-13.8%
WECC-SRSG	16.3%	11.8%	-6.8%

[6] Energy and capacity is sufficient for a broad range of normal and above-normal scenarios in the NPCC-New England area for the summer. This negative reserve margin indicates that a scenario combining extreme high demand and extremely-low resources could, however, result in an energy emergency.

Transfers in a Wide-Area Event

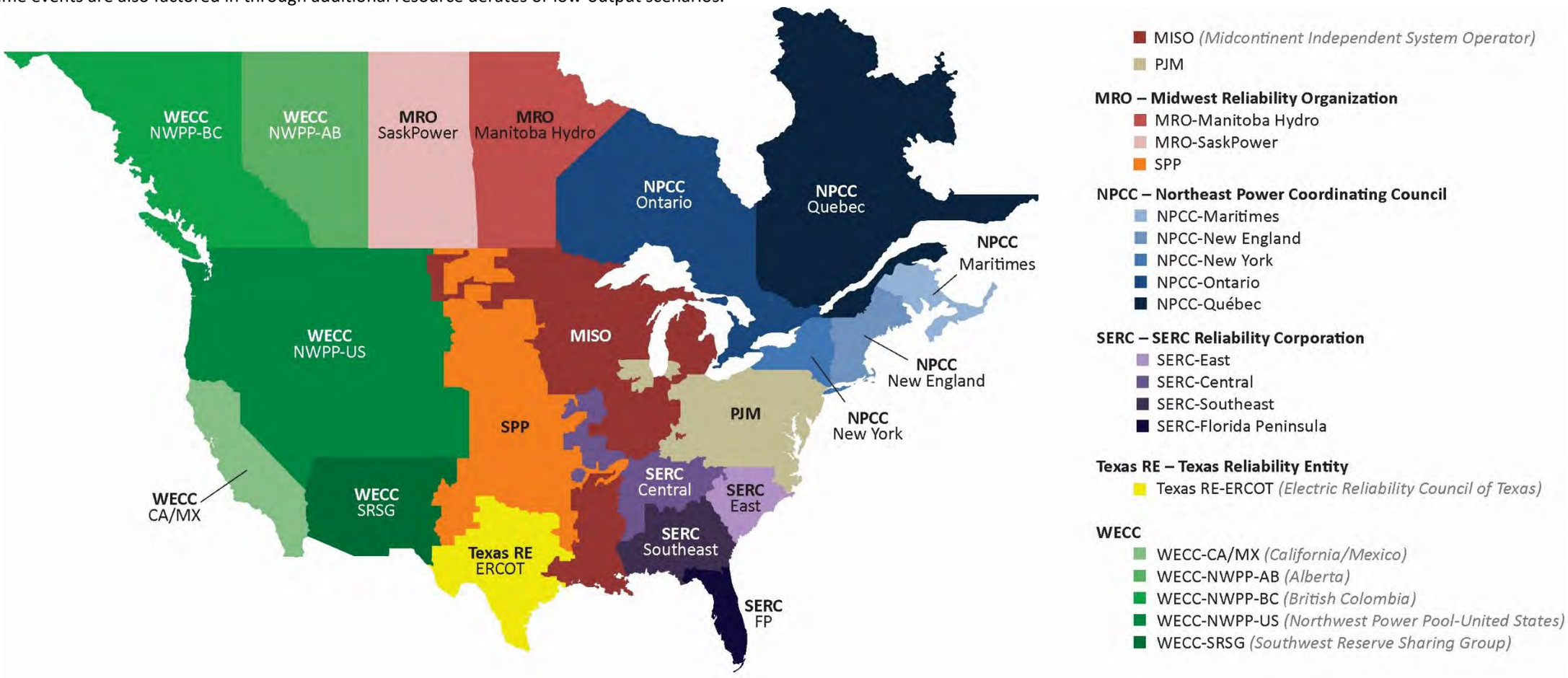
When above-normal temperatures extend over a wide area, resources can be strained in multiple assessment areas simultaneously, increasing the risk of shortfalls. Some assessment areas expect imports from other areas to be available to meet periods of peak demand and have contracted for firm transfer commitments. A summary of area firm on-peak imports and exports is shown in **Table 3**. Firm resource transactions like these are accounted for in all assessment area anticipated resources and reserve margins. Areas with net imports show a positive transfer amount, and areas with net exports show a negative transfer amount. Only areas that contained transfers for the previous or upcoming summer seasons are shown in **Table 3**; the data in this table is sourced from the data adequacy tables in the **Data Concepts and Assumptions** section. In the unlikely event that multiple assessment areas are experiencing energy emergencies as could occur in a wide-area heatwave, some transfers may be at risk of not being fulfilled. Transfer agreements may include provisions that allow the exporting entity to prioritize serving native load. Loss of transfers could exacerbate resource shortages that occur from outages and derates.

Table 3: 2021 and 2022 On-Peak Net Firm Transfers

Assessment Area	2021 Summer Transfers (MW)	2022 Summer Transfers (MW)	Year-to-Year Change
MISO	2,979	1,353	-54.6%
MRO-Manitoba	-1,596	-1,816	13.8%
MRO-SaskPower	125	290	132.0%
NPCC-Maritimes	-57	64	-212.3%
NPCC-New England	1,208	1,292	7.0%
NPCC-New York	1,816	2,465	35.7%
NPCC-Ontario	80	150	87.5%
NPCC-Québec	-1,995	-2,304	15.5%
PJM	1,460	124	-91.5%
SERC-Central	172	-795	-561.6%
SERC-East	562	612	8.9%
SERC-Florida Peninsula	1,007	300	-70.2%
SERC-Southeast	-1,115	-2,524	126.4%
SPP	186	-144	-177.6%
Texas RE-ERCOT	210	20	-90.5%
WECC-AB	0	437	N/A
WECC-BC	0	0	N/A
WECC-CA/MX	686	0	-100.0%
WECC-NWPP-US	6,139	2,517	-59.0%
WECC-SRSG	866	1,002	15.7%

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six Regional Entities on an assessment area basis. The operational risk analysis shown in the following regional assessments dashboard pages provides a deterministic scenario for understanding how various factors that affect resources and demand can combine to impact overall resource adequacy. For each assessment area, there is a risk-period scenario graphic; the left blue column shows anticipated resources (from the **Demand and Resource Tables**), and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand (from the **Demand and Resource Tables**) and the extreme summer peak demand determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources. Adjustments may include reductions for typical generation outages (maintenance and forced not already accounted for in anticipated resources) and additions that represent the quantified capacity from operational tools (if any) that are available during scarcity conditions but have not been accounted for in the SRA reserve margins. Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The cumulative effects from extreme events are also factored in through additional resource derates or low-output scenarios.



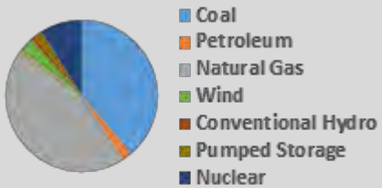


MISO

MISO is a not-for-profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency.

MISO manages energy, reliability, and operating reserve markets that consist of 36 local BA and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three Regional Entities, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

On-Peak Fuel Mix



Highlights

- Tighter than normal operating conditions are anticipated, particularly in the MISO North/Central region, which cleared too little capacity in the 2022–2023 PRA. The PRA capacity shortfall of 1,230 MW signals a potential for operating risk during peak summer conditions.
- Continued operating measures, such as MISO maximum generation events, can be expected in order to give system operators access load modifying resources (demand response) that can only be called upon once available generation is at maximum capacity.
- MISO performs an annual loss-of-load expectation (LOLE) study to determine its installed reserve margin and other probabilistic reliability indices. Based on results of the 2021 analysis, MISO expects low amounts of EUE in the summer season. The greatest risk occurs in the month of July, coinciding with the typical peak in annual demand.

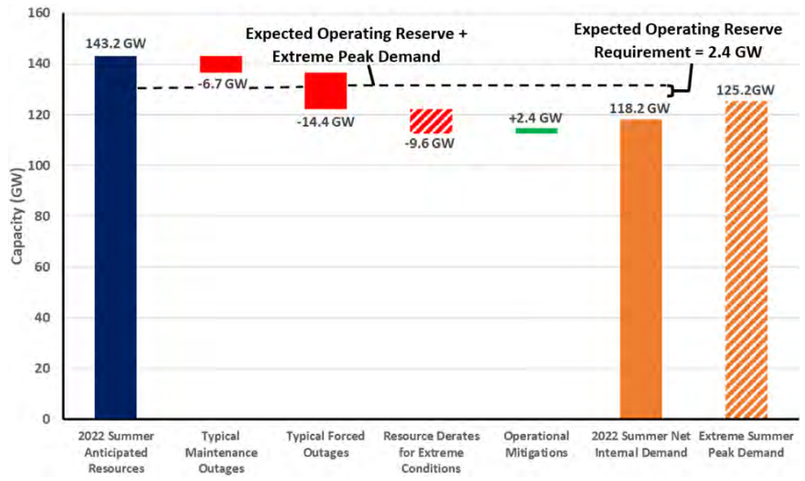
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under normal peak-demand and outage scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios studied.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

Maintenance Outages: Rolling five-year average of maintenance and planned outages

Forced Outages: Five-year average of all outages that were not planned

Extreme Derates: Maximum of last five years of outages

Operational Mitigations: Total of 2.4 GW capacity resources available during extreme operating conditions

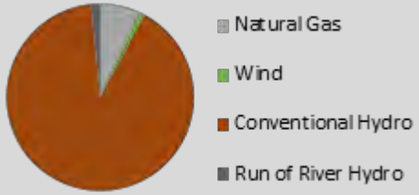


MRO-Manitoba Hydro

Manitoba Hydro is a provincial crown corporation that provides electricity to about 580,000 customers throughout Manitoba and natural gas service to about 282,000 customers in various communities throughout Southern Manitoba. The Province of Manitoba has a population of about 1.3 million in an area of 250,946 square miles.

Manitoba Hydro is winter-peaking. No change in the footprint area is expected during the assessment period. Manitoba Hydro is its own Planning Coordinator and Balancing Authority. Manitoba Hydro is a coordinating member of MISO. MISO is the Reliability Coordinator for Manitoba Hydro.

On-Peak Fuel Mix



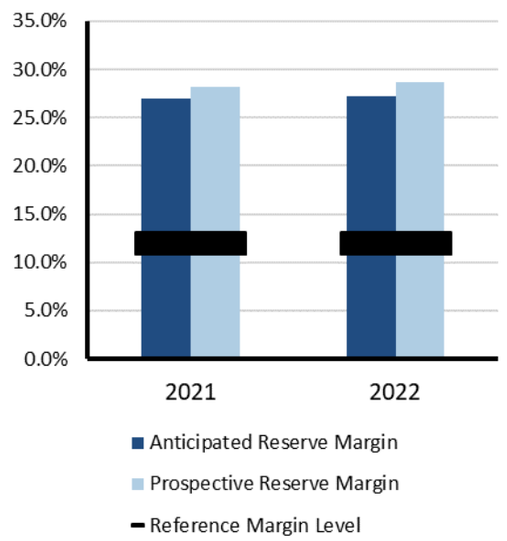
Highlights

- Manitoba Hydro is not anticipating any emerging reliability issues in its assessment area for the upcoming season.
- Four Keeyask hydro units were added this past year (approximately 93 MW each). Two additional Keeyask generating units are anticipated to come on line for Summer 2022, and these are listed as Planned Tier 1 generation.
- There are no significant seasonal reliability issues identified in neighboring assessment areas that have the potential to impact Manitoba Hydro operations.
- The probability-based resource adequacy risk assessment for the summer (June–September) season is that there is a very low risk of resource adequacy issues.

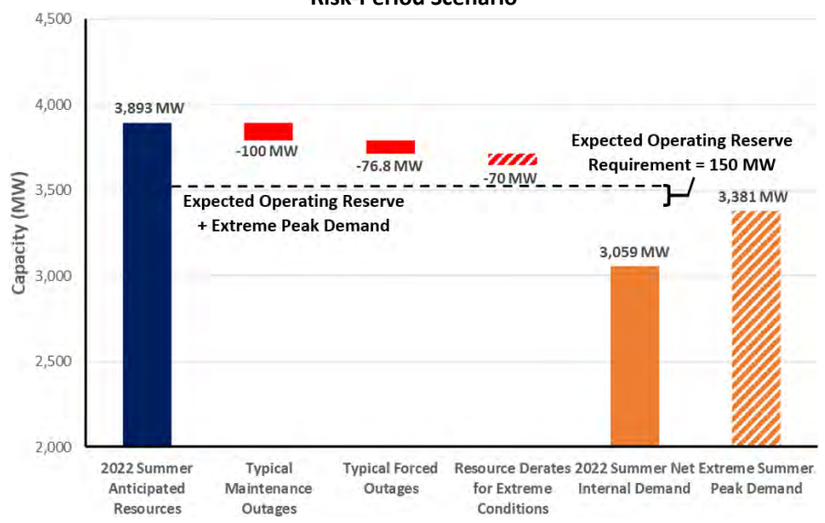
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and minimum probability of exceedance forecast load

Outages: Accounts for average forced outages, including 69 MW of reduced generation capacity due to drought conditions

Extreme Derates: Brandon units 6 and 7 summer capacity temperature derates



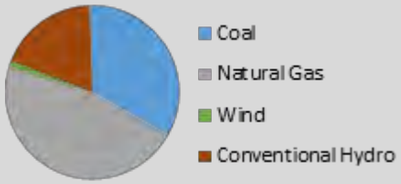
MRO-SaskPower

Saskatchewan is a province of Canada and comprises a geographic area of 651,900 square kilometers (251,700 square miles) with approximately 1.1 million customers. Peak demand is experienced in the winter.

The Saskatchewan Power Corporation (SaskPower) is the Planning Coordinator and Reliability Coordinator for the province of Saskatchewan and is the principal supplier of electricity in the province.

SaskPower is a provincial crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan Bulk Electric System (BES) and its interconnections.

On-Peak Fuel Mix



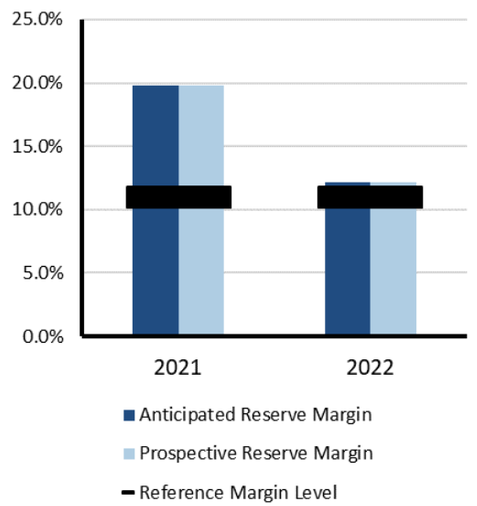
Highlights

- Saskatchewan experiences high load in summer as a result of extreme hot weather.
- SaskPower conducts an annual summer joint operating study with Manitoba Hydro with inputs from Basin Electric (North Dakota) and prepares operating guidelines for any identified issues.
- The risk of operating reserve shortage during peak load times or EEAs could increase if large generation forced outages combine with large planned maintenance outages during peak load times in May, June, July, August, and October.
- In case of extreme thermal conditions combined with large generation forced outages, SaskPower would use available demand response programs, short-term power transfers from neighboring utilities, and short-term load interruptions.
- SaskPower has performed a probability-based capacity adequacy study to assess risk of high forced outages that would lead to the use of emergency operating procedures. Forced outages of 300 MW or greater that coincide with peak demand may result in demand response and potential load interruptions to maintain system balance. There is an 8.2% probability of having forced outages of 300 MW or greater this summer.

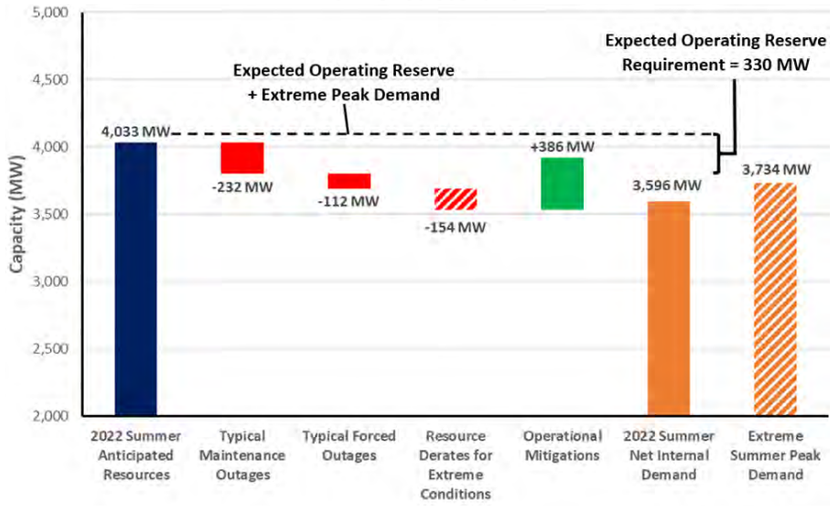
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and above-normal scenario based on peak demand with lighting and all consumer loads

Maintenance Outages: Average of planned maintenance outages for the summer months of June–September 2021

Forced Outages: Estimated by using SaskPower forced outage model

Operational Mitigations: Estimated average value based on short-term transfer capability from neighboring utilities for the upcoming 2022 summer



NPCC-Maritimes

The Maritimes assessment area is a winter-peaking NPCC area that contains two Balancing Authorities. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, and Prince Edward Island, and the Northern portion of Maine, which is radially connected to the New Brunswick power system. The area covers 58,000 square miles with a total population of 1.9 million.

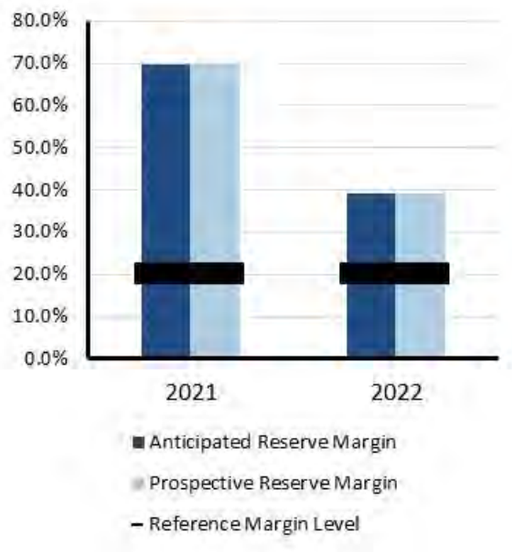
Highlights

- The Maritimes area has not identified any operational issues that are expected to impact system reliability. If an event was to occur, there are emergency operations and planning procedures in place. All of the area's declared firm capacity is expected to be operational for the summer operating period.
- Dual-fuel units will have sufficient supplies of heavy fuel oil on-site as part of the planning process to enable sustained operation in the event of natural gas supply interruptions.
- Based on an NPCC probabilistic assessment, the Maritimes assessment area shows a cumulative likelihood greater than 0.5 days/period of using their operating procedures and a cumulative likelihood of reducing their 30-minute reserve requirements (10 days/period) and initiating interruptible loads (5 days/period) over the 2022 summer period for the base case scenario, assuming the highest peak load levels.
- The Maritimes area is winter peaking. No significant cumulative LOLE, LOLH, and EUE risks were estimated over the summer May–September period for all scenarios simulated.

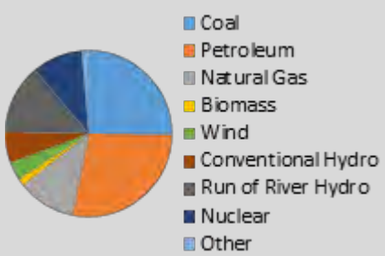
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios.

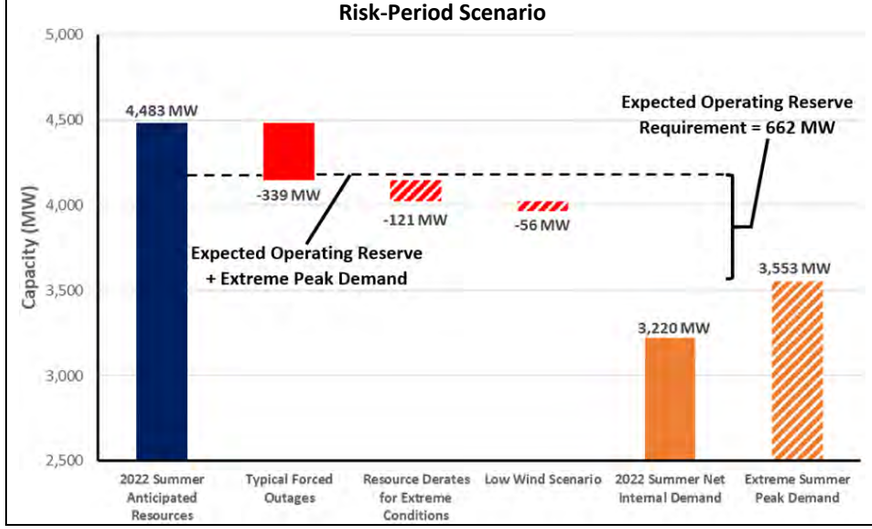
On-Peak Reserve Margins



On-Peak Fuel Mix



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (99/1) extreme demand forecast

Outages: Based on historical operating experience

Extreme Derates: Based on historical data for ambient temperature thermal de-rates

Low Wind Scenario: A low-likelihood scenario resulting in no wind resources

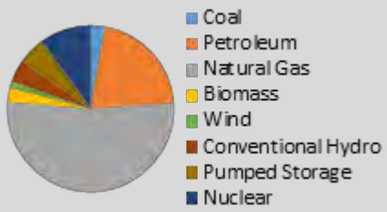


NPCC-New England

ISO New England (ISO-NE) Inc. is a regional transmission organization that serves the six New England states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. It is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administers the area's wholesale electricity markets, and manages the comprehensive planning of the regional BPS.

The New England BPS serves approximately 14.5 million customers over 68,000 square miles.

On-Peak Fuel Mix



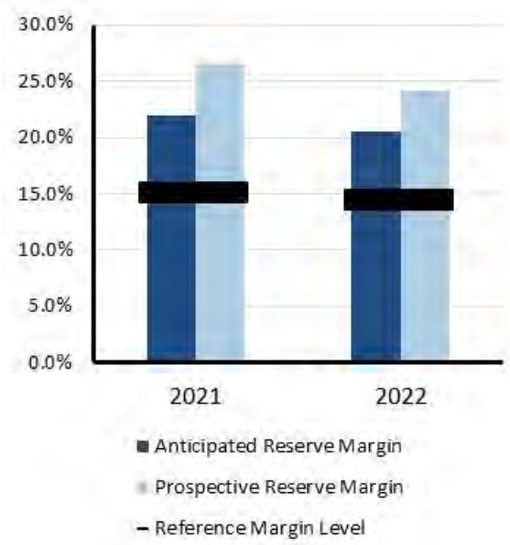
Highlights

- The New England area expects to have sufficient capacity to meet the 2022 summer peak demand forecast. As of April 5, 2022, the peak summer (net internal) demand is forecast to be 24,817 MW for the week of July 24, 2022, with a projected net margin of 1,705 MW (6.9%). The 2022 summer (net internal) demand forecast takes into account the demand reductions associated with energy efficiency, load management, behind-the-meter PV systems, and distributed generation.
- Based on an NPCC probabilistic assessment, ISO-NE may rely on limited use of its operating procedures designed to mitigate resource and energy shortages during the summer. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios except the severe low-likelihood case. This reduced resource case with highest peak load scenario resulted in a small estimated cumulative LOLE risk of ~0.6 days/period with associated LOLH (~2.1 hours/period) and EUE (~1,603 MWh/period) risk this is divided between June and August. This scenario is based exclusively on the two highest load levels with a 7% chance of occurring and a low resource case consisting of 10% reduction in NPCC resources and PJM reductions.

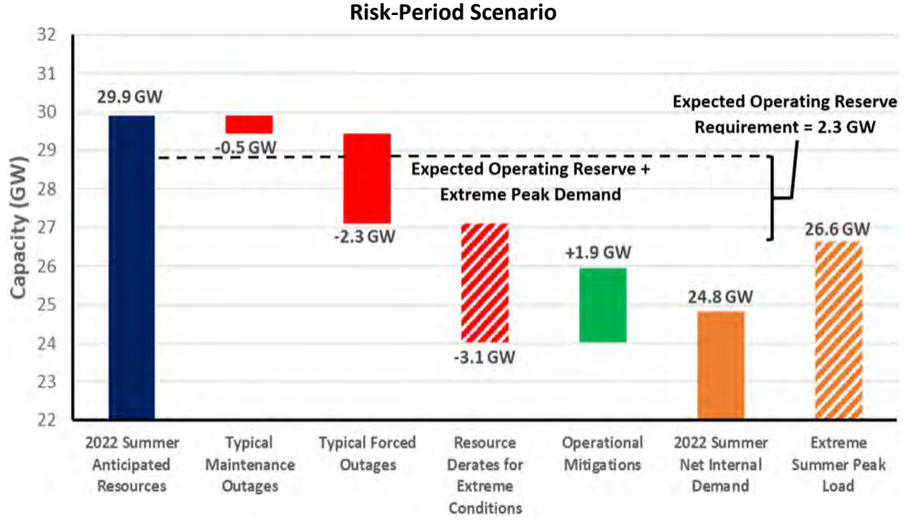
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load, combined with extreme outage conditions, could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at peak demand hour

Demand Scenarios: Peak net internal demand (50/50) and (90/10) extreme demand forecast

Maintenance & Forced Outages: Based on historical weekly averages

Extreme Derates: Represent a case that is beyond the (90/10) conditions based on historical observation of force outages, additional reductions for generation at risk due to operating issues at extreme hot temperatures, and other outage causes reported by generators

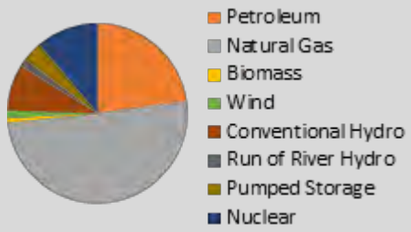
Operational Mitigations: Based on load and capacity relief assumed available from invocation of ISO-NE operating procedures



NPCC-New York

The New York Independent System Operator (NYISO) is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. The NYISO is the only Balancing Authority within the state of New York. The BPS encompasses over 11,000 miles of transmission lines, 760 power generation units, and serves 20.2 million customers. The established Reference Margin Level is 15%. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. However, New York requires load serving entities to procure capacity for their loads equal to their peak demand plus an IRM. The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). NYSRC approved the 2022–2023 IRM at 19.6%."

On-Peak Fuel Mix



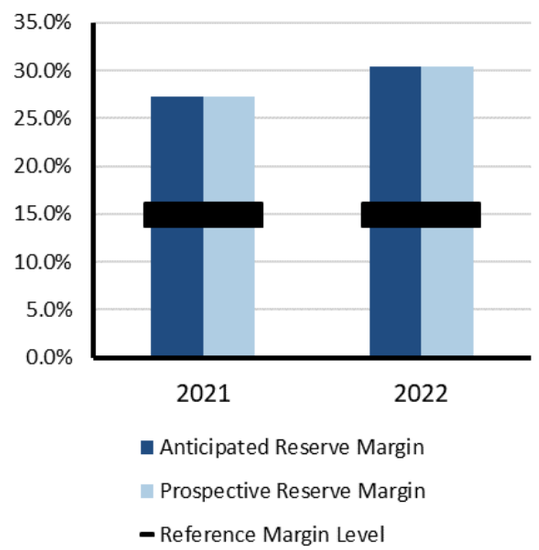
Highlights

- The NYISO is not anticipating any operational issues in the New York control area for the upcoming summer operating period. Adequate capacity margins are anticipated and existing operating procedures are sufficient to handle any issues that may occur.
- Based on an NPCC probabilistic assessment, NYISO is expected to require limited use of operating procedures designed to mitigate resource shortages during the summer. Only the highest peak load scenarios with base and reduced resource cases require operating procedures. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios.
- The analysis included simulation of a base case (normal 50/50 demand and expected resources) and a highest peak load scenario as well as including a low-likelihood reduced resource case that considers the impacts of extended maintenance in Southeastern New York, reduction in the effectiveness of demand response programs, and reduced import and transfer capabilities. This low-likelihood reduced resource scenario is based exclusively on the two highest load levels representing an average 10–15% increase in peak loads over the 50/50 forecast with a combined 7% probability of occurring. Additional constraints include an estimated 10% reduction in NPCC resources and PJM reductions.

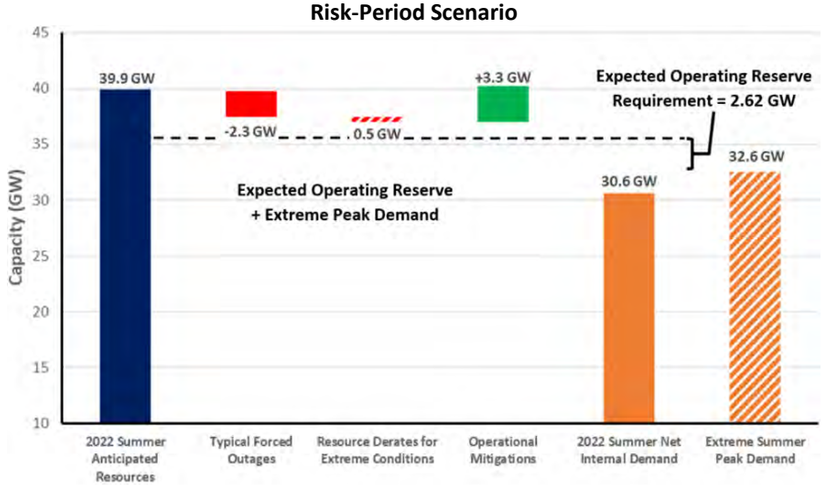
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) extreme demand forecast

Forced Outages: Based on historical 5-year averages

Operational Mitigations: A total of 3.3 GW based on operational/emergency procedures in area *Emergency Operations Manual*

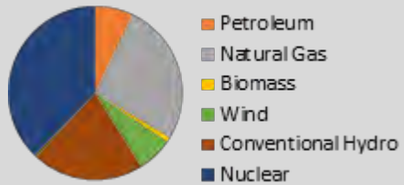


NPCC-Ontario

The Independent Electricity System Operator (IESO) is the Balancing Authority for the province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of more than 14 million.

Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

On-Peak Fuel Mix



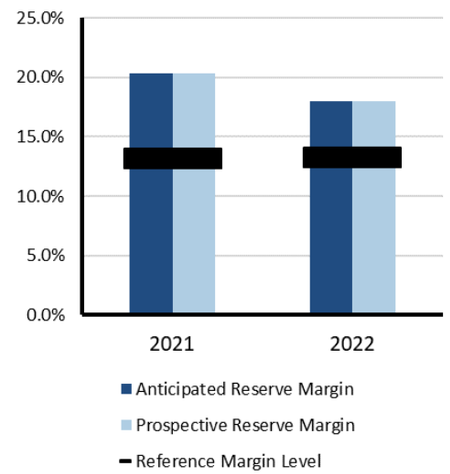
Highlights

- The ongoing transmission outage at the New York-St Lawrence interconnection continues to impact import and export capacity between Ontario and New York. This issue is expected to be resolved by the third quarter of 2022.
- Ontario is entering a period of tighter supply conditions brought on by rising demand and the ongoing nuclear refurbishment program; during summer months, planned generation maintenance outages will be more challenging to accommodate than they have been previously. Nonetheless, Ontario expects to have sufficient generation resources available to meet its needs throughout the summer of 2022, and its transmission system is expected to continue to reliably supply province-wide demand throughout the season.
- Based on an NPCC probabilistic assessment, IESO is expected to require limited use of operating procedures designed to mitigate resource shortages during the summer for the low-likelihood reduced resource case. This low-likelihood reduced resource scenario is based exclusively on the two highest load levels that represent an average 10–15% increase in peak loads over the 50/50 forecast with a combined 7% probability of occurring. Additional constraints include an estimated 10% reduction in NPCC resources and PJM reductions.
- Negligible cumulative LOLE, LOLH, and EUE risks are estimated over the May–September summer period for all simulated scenarios.

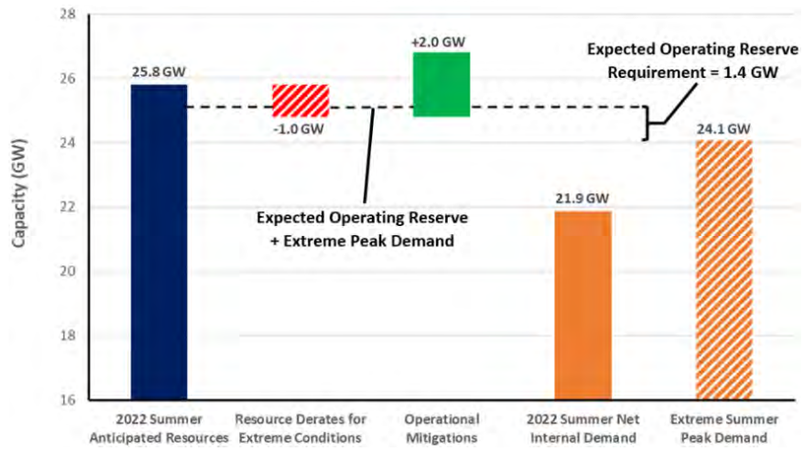
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios studied.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50 Forecast) and highest weather-adjusted daily demand based on 31 years of demand history

Extreme Derates: Derived from weather-adjusted temperature rating of thermal units and adjustments to expected hydro production for low water conditions

Operational Mitigations: Imports anticipated from neighbors during emergencies

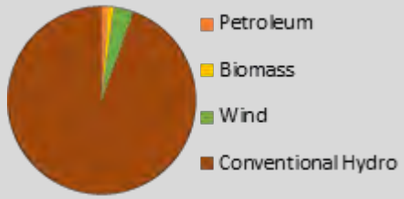


NPCC-Québec

The Québec assessment area (Province of Québec) is a winter-peaking NPCC area that covers 595,391 square miles with a population of 8 million.

Québec is one of the four Interconnections in North America; it has ties to Ontario, New York, New England, and the Maritimes; consisting of either HVDC ties, radial generation, or load to and from neighboring systems.

On-Peak Fuel Mix



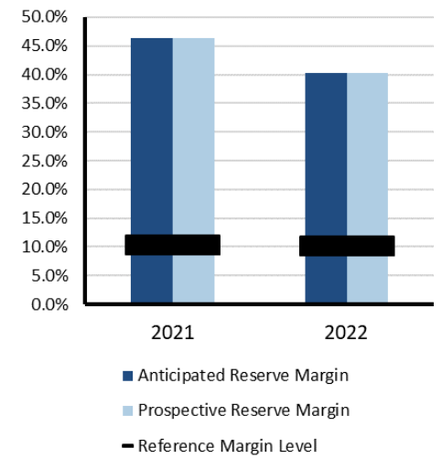
Highlights

- Québec is a winter peaking system, and no particular resource adequacy problems are forecast for the upcoming summer.
- Québec expects to be able to provide assistance to other areas if needed up to the transfer capability available.
- Québec has had no major generation or transmission additions since the *2021 NERC SRA*.
- The Québec assessment area is not expected to require use of their operating procedures that are designed to mitigate resource shortages during the summer of 2022 based on an NPCC probability assessment. The Québec area is winter peaking and has a large reserve margin for the summer period. As a result, Québec does not indicate having any measurable amounts of cumulative LOLE, LOLH, or EUE risks over the May–September summer period for all the scenarios modeled.

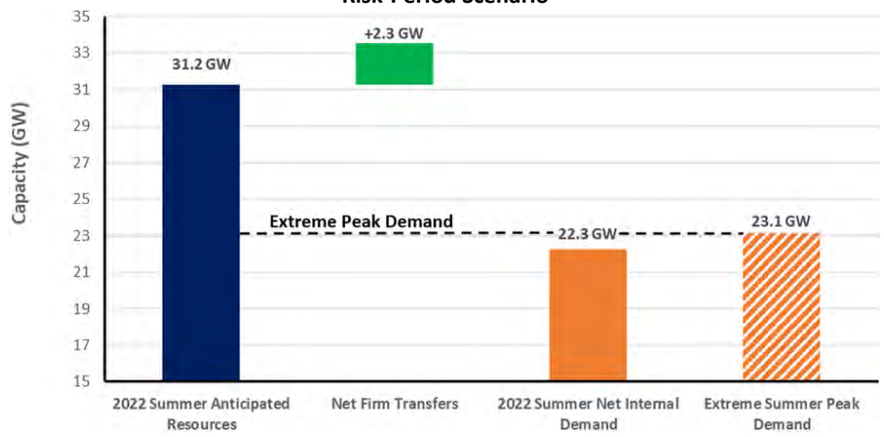
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Net Firm Transfers: Imports anticipated from neighbors during emergencies

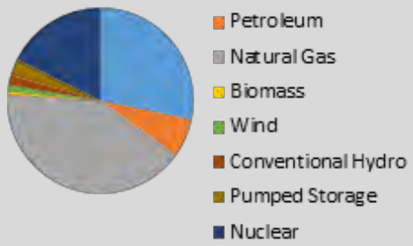


PJM

PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM serves 65 million customers and covers 369,089 square miles.

PJM is a Balancing Authority, Planning Coordinator, Transmission Planner, Resource Planner, Interchange Authority, Transmission Operator, Transmission Service Provider, and Reliability Coordinator.

On-Peak Fuel Mix



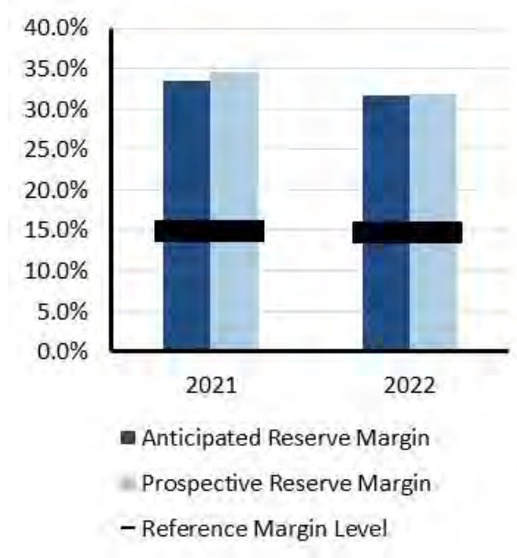
Highlights

- PJM expects no resource problems over the entire 2022 summer peak season because installed capacity is over two times the reserve requirement.
- PJM continues to request fuel inventory and supply data of coal and oil resources (including dual-fuel units). This data request, sent every two weeks, started prior to the 2021–2022 winter season as a result of increasing reports of existing and future supply shortages of fuel and non-fuel consumables. In order to maintain situational awareness throughout the spring and into the summer of 2022, PJM is continuing efforts to monitor potential impacts of fuel and non-fuel consumables supply as well as delivery status on generation resources.
- PJM is expecting a low risk of experiencing periods of resources falling below required operating reserves during Summer 2022 based on the 2021 PJM Reserve Requirement Study. As indicated in the study, PJM is forecasting around 33% installed reserves (including expected committed Demand Resources), well above the target installed reserve margin of 14.9%.
- No other reliability issues are expected.

Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Based on historical data and trending

Extreme Derates: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 2.3 GW based on operational/emergency procedures



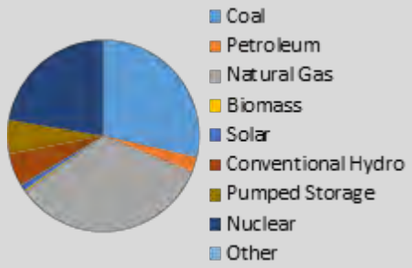
SERC-East

SERC-East is a summer-peaking assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina.

SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million.

The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

On-Peak Fuel Mix



Highlights

- Entities in SERC-East have not identified any potential reliability issues for the upcoming season. The entities continue to perform resource studies to ensure resource adequacy to meet the summer peak demand and to maintain system reliability. Entities reported that coal inventory is in the upper allowed range to maintain reliability.
- Entities in SERC-East continue to participate actively in the SERC Near-Term and Long-Term Working Groups. These groups identify emerging and potential reliability impacts to transmission and resource adequacy as well as with transfer capability.
- Entities in SERC-East are not anticipating operational challenges for the upcoming summer season.
- Probabilistic analysis performed for SERC-East shows almost no risk for resource shortfall for the summer. SERC-East has a small amount of EUE in August but a negligible amount at other times (EUE < 0.4 MWh).

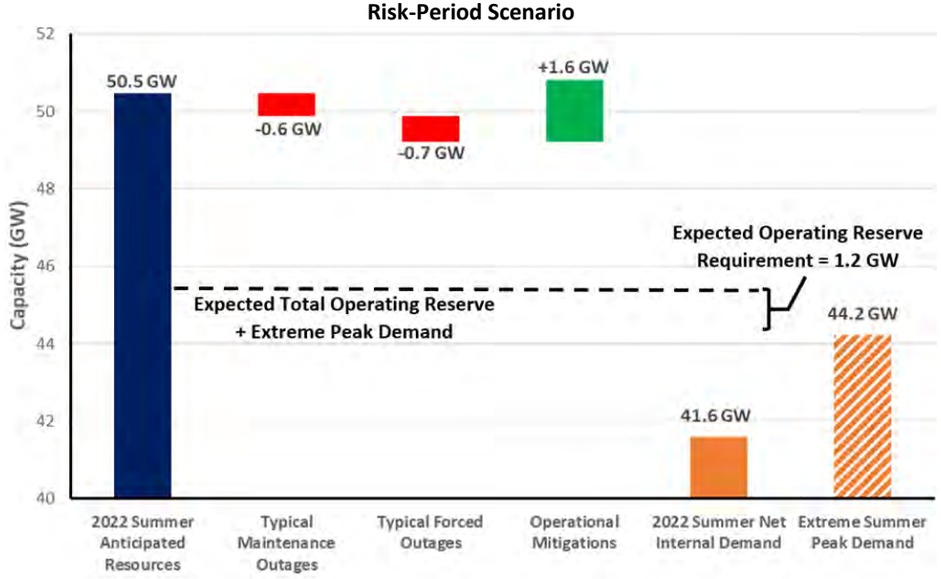
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 1.6 GW based on operational/emergency procedures



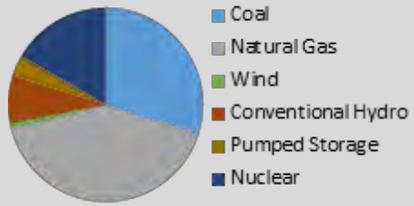
SERC-Central

SERC-Central is a summer peaking assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee, portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky.

SERC-Central is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission approved delegation agreements with NERC. SERC-Central is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million.

The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

On-Peak Fuel Mix



Highlights

- Entities in SERC-Central continue to work collaboratively to ensure reliability for its area within SERC and to promote reliability and adequacy.
- Entities in SERC-Central continue to participate actively in the SERC Near-Term and Long-Term Working Groups, among others, in order to identify and address emerging and potential reliability impacts to transmission and resource adequacy along with transfer capability.
- Entities in SERC-Central have not identified any potential reliability issues for the upcoming summer season.
- Entities anticipate having adequate system capacity for the upcoming season and are equipped to address unexpected, short-term issues leveraging its diverse generation portfolio and spot purchases from the power markets when necessary.
- Probabilistic analysis performed for SERC-Central indicates minimal risk for resource shortfall.

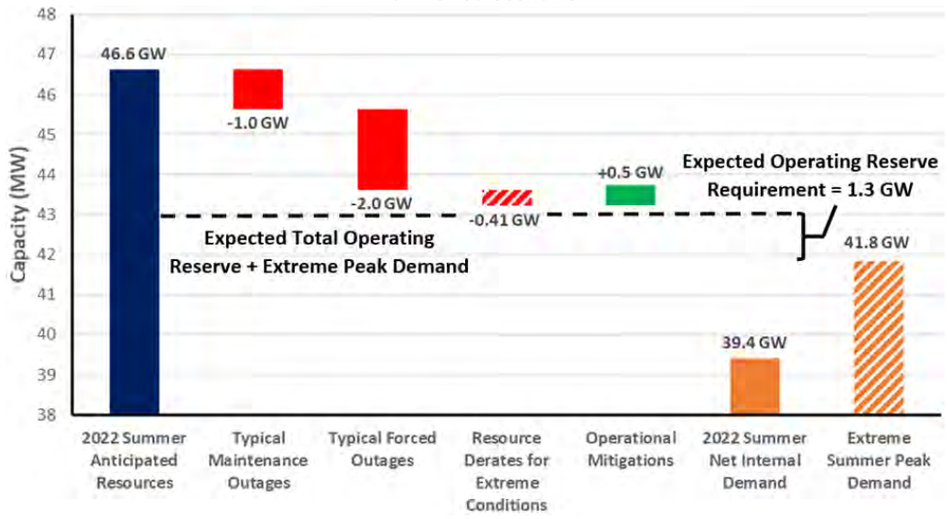
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 0.5 GW based on operational/emergency procedures



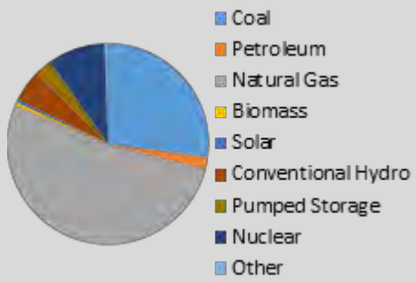
SERC-Southeast

SERC-Southeast is a summer peaking assessment area within the SERC Regional Entiey. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi.

SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million.

The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

On-Peak Fuel Mix



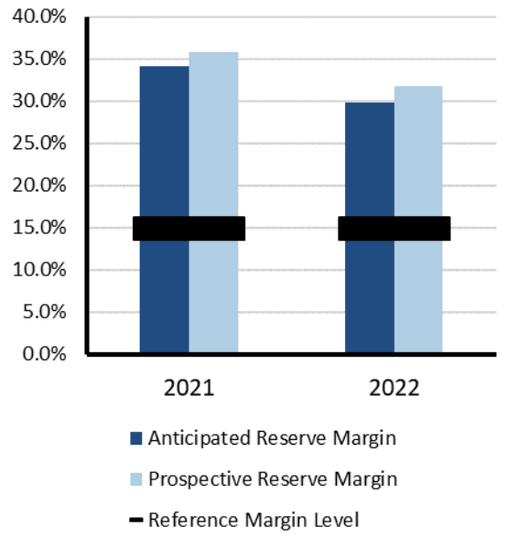
Highlights

- Entities in SERC-Southeast have not identified any emerging reliability issues for the upcoming summer that will impact resource adequacy. The available system capacity for the upcoming summer meets or exceeds the reserve margin target. Reliability is supported by a diverse fuel mix, firm natural gas contracts, and power purchases.
- Entities in SERC-Southeast continue to participate actively in the SERC Near-Term and Long-Term Working Groups. These groups identify emerging and potential reliability impacts to transmission and resource adequacy along with transfer capability.
- Probabilistic analysis performed for SERC-Southeast shows there is low risk for resource shortfall for the summer. Load loss and unserved energy indices are negligible for SERC-Southeast throughout the summer.

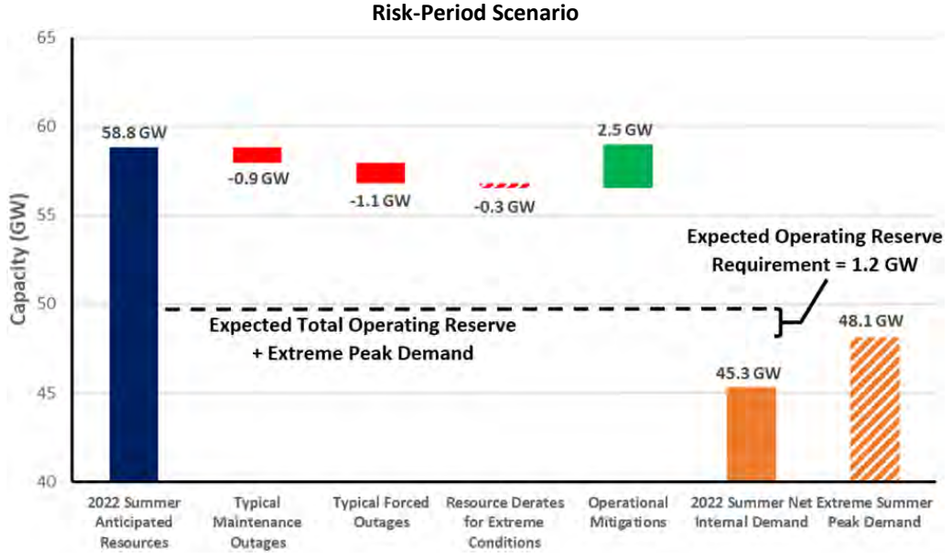
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 2.5 GW based on operational/ emergency procedures



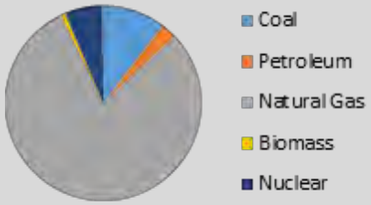
SERC-Florida Peninsula

SERC-Florida Peninsula is a summer peaking assessment area within SERC.

SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million.

The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

On-Peak Fuel Mix



Highlights

- Entities in SERC-Florida Peninsula have not identified any emerging reliability issues or operational concerns for the upcoming summer.
- Entities in SERC-Florida Peninsula continue to participate actively in the SERC Near-Term and Long-Term Working Groups. These groups identify emerging and potential reliability impacts to transmission and resource adequacy along with transfer capability.
- Entities within the Florida Peninsula area have reported no operational challenges for the upcoming summer based on current expected system conditions. The BES within the Florida Peninsula is expected to perform reliably for the anticipated 2022 summer season.
- SERC Probabilistic analysis performed for SERC-Florida Peninsula shows there is low risk for resource shortfall for the summer. Load loss and unserved energy indices for SERC-Florida Peninsula are spread across the summer months and remain relatively low (LOLH < 0.03 and EUE < 18 MWH).

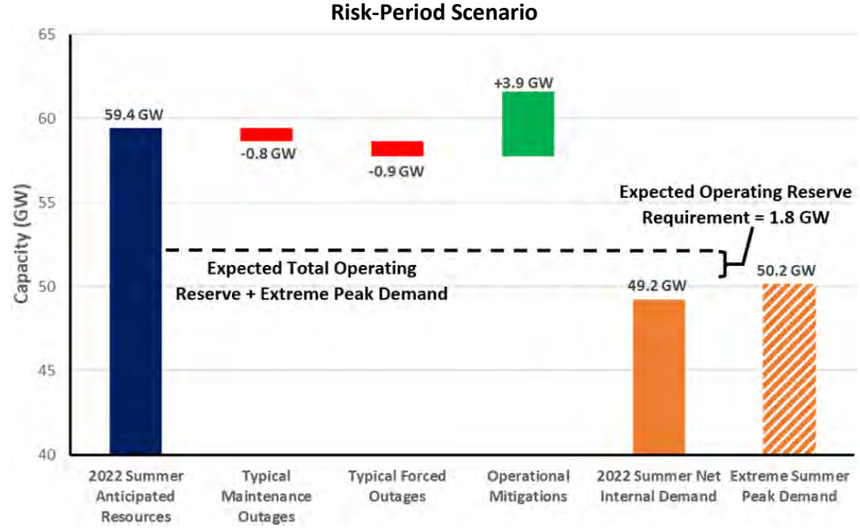
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 3.9 GW based on operational/ emergency procedures

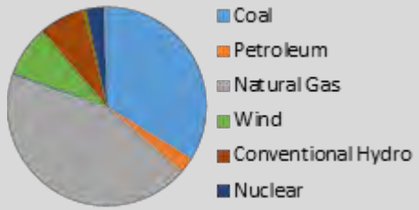


SPP

Southwest Power Pool (SPP) Planning Coordinator footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming.

The SPP long-term assessment is reported based on the Planning Coordinator footprint, which touches parts of the Midwest Reliability Organization Regional Entity and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million.

On-Peak Fuel Mix



Highlights

- SPP projects a low likelihood of any emerging reliability issues impacting the area for the 2022 summer season.
- The current planning reserve margin should minimize risks of BA capacity deficiencies for summer.
- BA generation capacity deficiency risks remain depending on wind generation output levels and unanticipated generation outages in combination with high load periods.
- There are concerns that drought conditions will impact the Missouri River and other water sources used by generation resources that rely on once-through cooling processes.
- Using current operational processes and procedures, SPP will continue to assess the needs for the 2022 summer season and will adjust as needed to ensure that real time reliability is maintained throughout the summer.

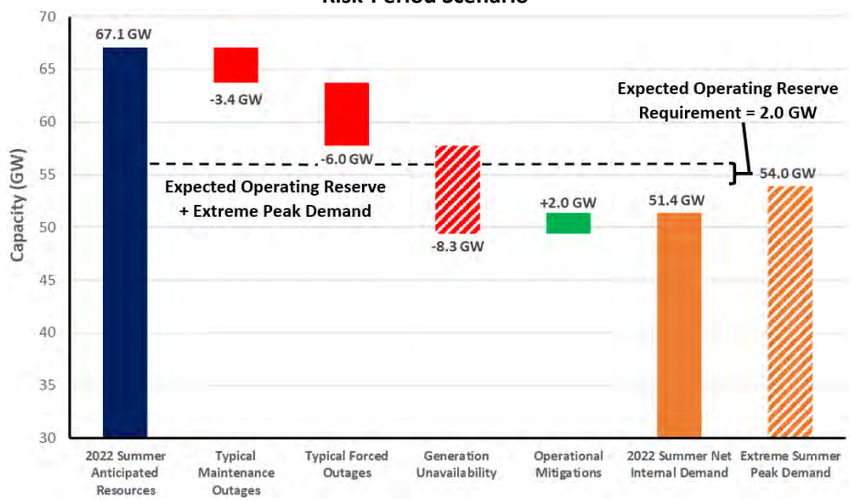
Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios studied.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand is a 5% increase from net internal demand

Maintenance & Forced Outages: Calculated from SPP's generator assessment process

Generation Unavailability: Risk from higher outages to protect against 99.5th percentile of historical coincident generation

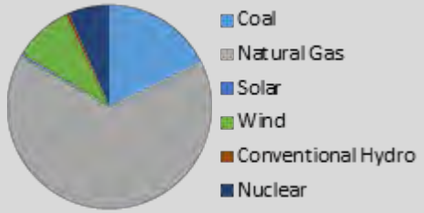
Operational Mitigations: A total of 2 GW of behind the meter generation and demand response to be deployed in the event of an emergency alert



Texas RE-ERCOT

The Electric Reliability Council of Texas (ERCOT) is the ISO for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT is a summer-peaking Regional Entity that covers approximately 200,000 square miles, connects over 52,700 miles of transmission lines, has over 1,000 generation units, and serves more than 26 million customers. Lubbock Power & Light joined the ERCOT grid on June 1, 2021. Texas RE is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for the ERCOT Regional Entity.

On-Peak Fuel Mix



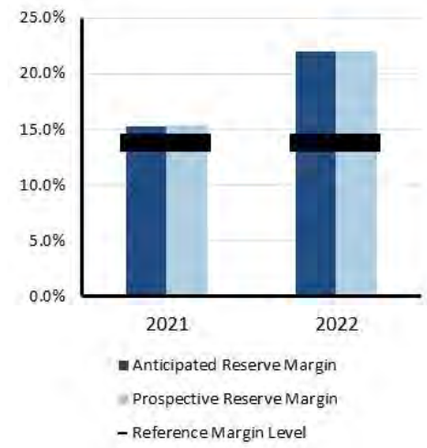
Highlights

- The amount of renewable installed capacity expected to be available during upcoming summer peak demand hours is higher by about 4,100 MW relative to the amount reported in last year's SRA.
- Most of ERCOT is experiencing severe drought conditions, setting the stage for a hotter-than-normal summer.
- Transmission expansion projects in development to add resources or address system performance are being closely monitored for delays or cancellations. Occurrences may contribute to localized reliability concerns.
- On May 9, 2021, a single-line-to-ground fault occurred at a combined-cycle power plant near Odessa, Texas. The fault impacted several solar and wind plants. In response to the NERC report on the disturbance event, ERCOT established an Inverter-based Resource Task Force to facilitate assessment of recommendations to address IBR issues identified in the report.
- An emerging challenge for transmission planning and system operations is the interest in developing new cryptocurrency mining facilities in ERCOT. ERCOT and its stakeholders have recently formed a task force to address the issues associated with these large flexible loads.
- ERCOT's Summer 2022 probabilistic assessment indicates a low risk (6% probability) of declaring a Level 1 Energy Emergency Alert (EEA1) during the expected daily peak load hour. The EEA1 risk is slightly higher from 6:00–8:00 p.m. Central time with the highest-risk hour being 7:00 p.m. This shifting of capacity scarcity risk to later hours is due to the large increase in solar capacity over the last two years. Nevertheless, the overall daily risk is lower than for the Summer 2021 model simulation. For example, the EEA1 peak load hour risk for Summer 2021 was higher at 12%.

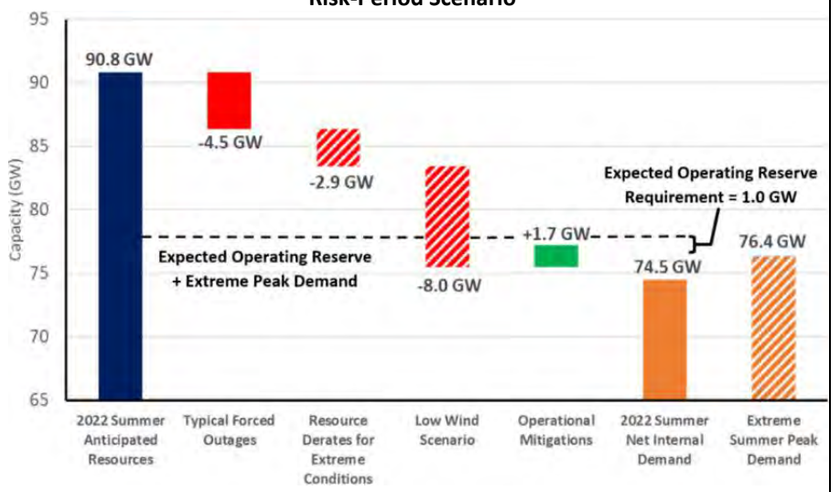
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ interruptible load programs and additional operating mitigations reflected in the scenario. Load shedding may be needed under extreme peak demand and outage scenarios studied.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand represents 90th percentile of forecasted summer peaks from 2006–2020

Forced Outages: Based on the historical averages of forced outages for June through September weekdays, hours ending 3:00–8:00 p.m. local time for the last three (2019–2021) summer seasons

Extreme Derates: Based on the 95th percentile of historical averages of forced outages for June through September weekdays, hours ending 3:00–8:00 p.m. local time for the last three (2019–2021) summer seasons

Operational Mitigations: Additional capacity from switchable generation and additional imports



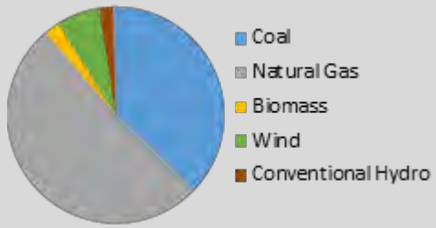
WECC-NWPP-AB

WECC-NWPP-AB (Alberta) is an assessment area in the WECC Regional Entity that consists of the province of Alberta, Canada.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members, which include 39 Balancing Authorities, represent a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity.

WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the Northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

On-Peak Fuel Mix



Highlights

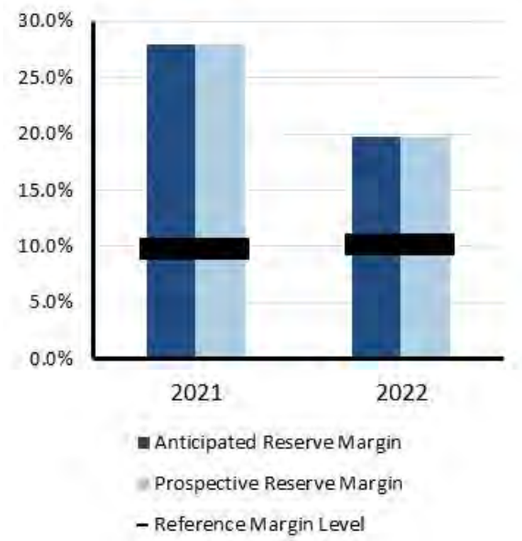
- There are potential natural gas supply-side tightening concerns.
- Reserve margins are tighter but still expected to be adequate.
- Based on a WECC probabilistic assessment, the WECC-NWPP-AB assessment area had negligible LOLH and EUE.

  On the peak risk hour at 6:00 p.m. local time, under a summer peak defined as a one-in-ten probability at the 90th percentile, and with either one of the combination of derates on their own or any two in combination, Alberta is expected to have sufficient resource availability to meet demand and cover reserves. However, if all derate conditions were combined concurrently, Alberta would likely need to seek external assistance for imports.

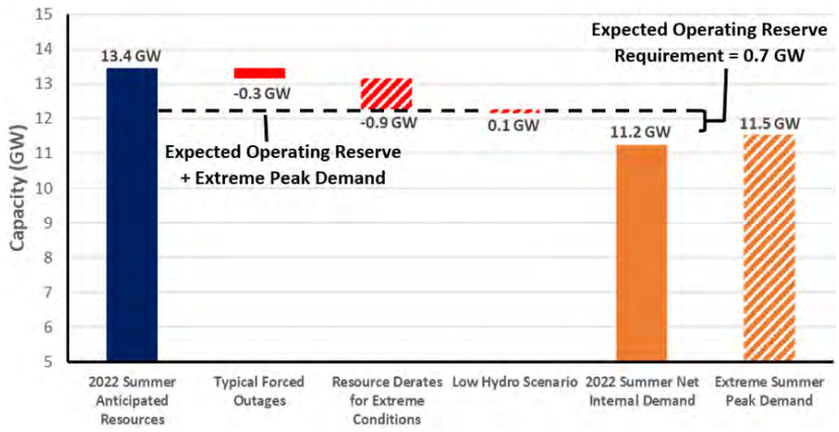
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios studied.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Low Hydro Scenario: Reduced hydro availability resulting from drought conditions



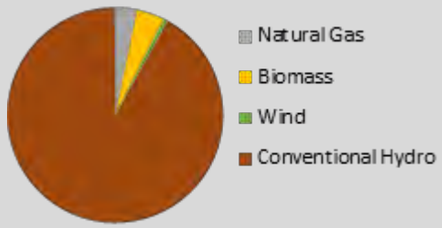
WECC-NWPP-BC

WECC-NWPP-BC (British Columbia) is an assessment area in the WECC Regional Entity that consists of the province of British Columbia, Canada.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members, which include 39 Balancing Authorities, represent a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity.

WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the Northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

On-Peak Fuel Mix



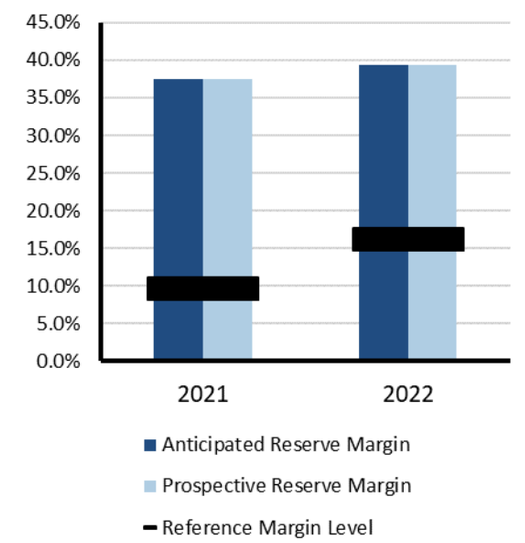
Highlights

- Planned resources in Tier 1 have moved into existing certain.
- Reserve margins are up across the board and adequate.
- Based on a WECC probabilistic assessment, the WECC-NWPP-BC assessment area had negligible LOLH and EUE.
- On the peak risk hour at 6:00 p.m. local time, under a summer peak defined as a 1-in-10 probability at the 90th percentile, and with any combination of derates other than hydro, BC is expected to have sufficient resource availability to meet demand and cover reserves. However, if a 1-in-10 probability at the 10th percentile of hydro conditions was to occur, BC would need to locate external assistance for imports. Summer 2022 hydro availability in BC is not expected to fall that low despite continued mega-drought conditions across much of the West.

Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Low Hydro Scenario: Reduced hydro availability resulting from drought conditions



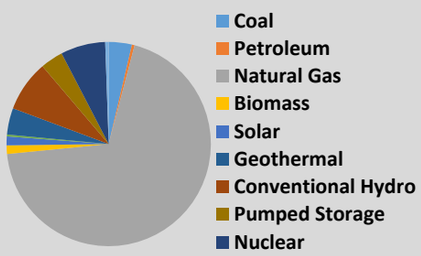
WECC-CA/MX

WECC-CA/MX (California-Mexico) is an assessment area in the WECC Regional Entity that includes parts of California, Nevada, and Baja California, Mexico.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members, which include 39 Balancing Authorizes, represent a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity.

WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the Northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

On-Peak Fuel Mix



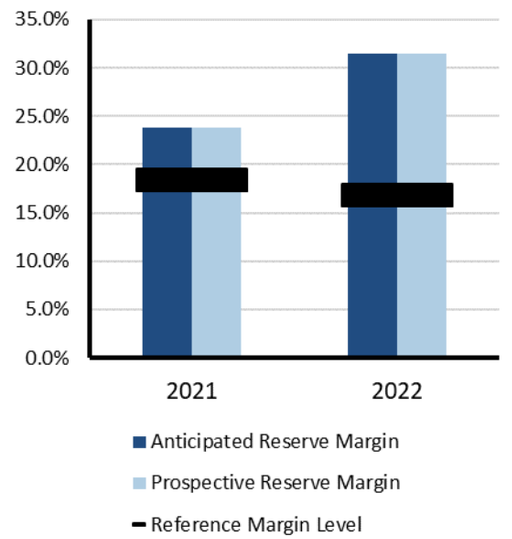
Highlights

- California ISO is procuring resources to improve reliability risks.
- Localized short-term operational issues may occur due to wildfires, droughts, and/or supply chain issues.
- As cooling degree days continue to rise across the Western Interconnection, there is a risk that is higher than the historical average of prolonged heatwave events
- Based on a WECC probabilistic assessment, the California portion of the assessment area is projected to have an LOLH of 1.0 hours and an EUE of 4 MWh. The Mexico portion is projected to have an LOLH of 10.0 hours and an EUE of 100 MWh.
- On the peak risk hour at 8:00 p.m. local time, there is an under 1-in-10 summer peak probability at the 90th percentile, including firm transfers. The CA/MX area is not expected to have sufficient resource availability to meet demand and cover reserves under any of the scenarios on their own, including typical forced outages; CA/MX will need to locate additional external assistance for imports.

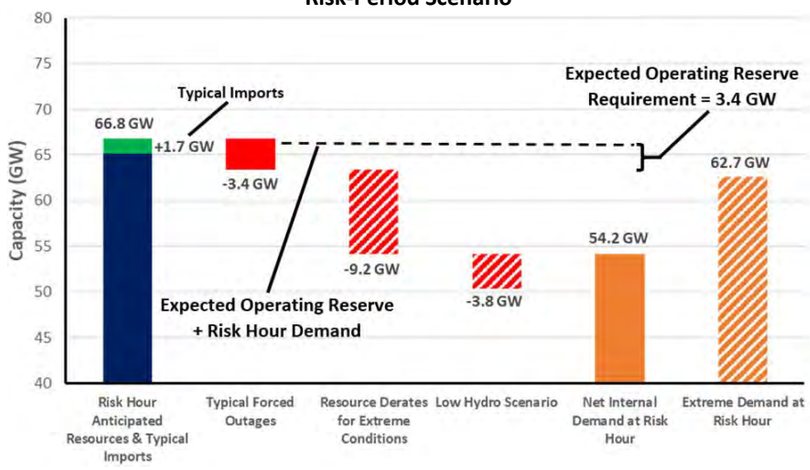
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios studied.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at 8:00 p.m. local time as solar PV output is diminished and demand remains high

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Estimated using market forced outage model

Extreme Derates: On natural gas units based on historic data and manufacturer data for temperature performance and outages

Low Hydro Scenario: Reduced hydro availability resulting from drought conditions



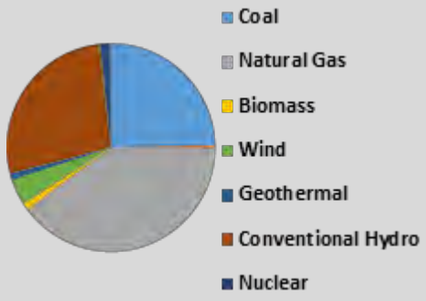
WECC-NWPP-US

WECC-NWPP-US (Northwest Power Pool) is an assessment area in the WECC Regional Entity. The area includes Colorado, Idaho, Montana, Oregon, Utah, Washington, Wyoming and parts of California, Nebraska, Nevada, and South Dakota.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members, which include 39 Balancing Authorities, represent a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity.

WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the Northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

On-Peak Fuel Mix



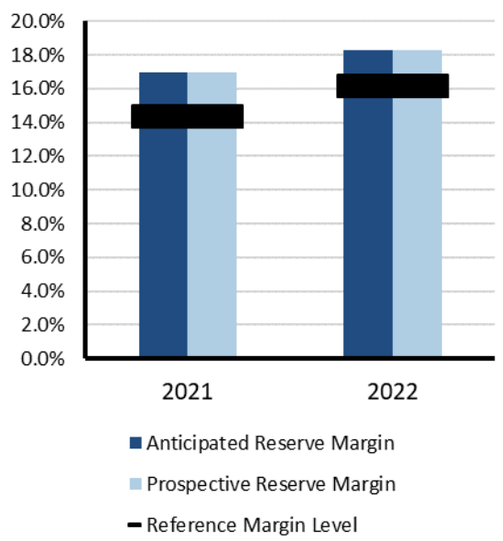
Highlights

- Potential drought conditions remain a concern.
- Reserve margins are up across the board and adequate.
- Based on a WECC probabilistic assessment, the WECC-NWPP-US assessment area had negligible LOLH and EUE.
- On the peak risk hour at 7:00 p.m., local time and under a summer peak defined as a 1-in-10 probability, including firm transfers, the WECC-NWPP-US area is not expected to have sufficient resource availability to meet demand and cover reserves under any of the scenarios on their own, including typical forced outages; WECC-NWPP-US will need to locate additional external assistance for imports.

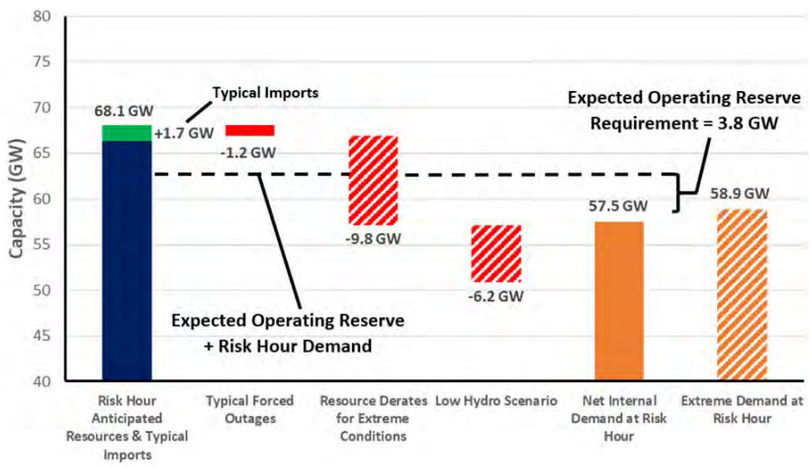
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios studied.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at 7:00 p.m. local time as solar PV output is diminished and demand remains high

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Low Hydro Scenario: Reduced hydro availability resulting from drought conditions



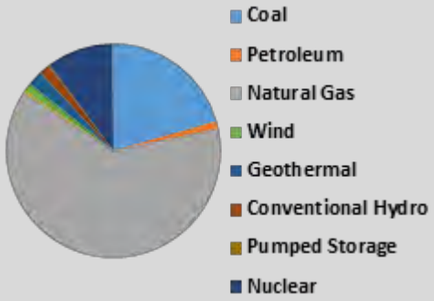
WECC-SRSG

WECC-SRSG (Southwest Reserve Sharing Group) is an assessment area in the WECC Regional Entity. It includes Arizona, New Mexico, and part of California and Texas.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members, which include 39 Balancing Authorities, represent a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity.

WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada as well as the Northern portion of Baja California in Mexico and all or portions of the 14 Western United States in between.

On-Peak Fuel Mix



Highlights

- Drought and supply chain issues are the main reliability concerns. Many solar developers are indicating to utilities that they will not be able to meet expected commission dates under executed and approved power purchase agreements, including at least 120 MW of PV planned for the 2022 summer.
- Reserve margins are expected to be adequate.
- Based on a WECC probabilistic assessment, the WECC-SRSG assessment area had negligible LOLH and EUE.
- On the peak risk hour is at 7:00 p.m., local time, under a summer peak defined as a 1-in-10 probability, and with either one of the derates on their own, SRSG is not expected to have sufficient resource availability to meet demand and cover reserves; SRSG will likely need to locate additional external assistance for imports.

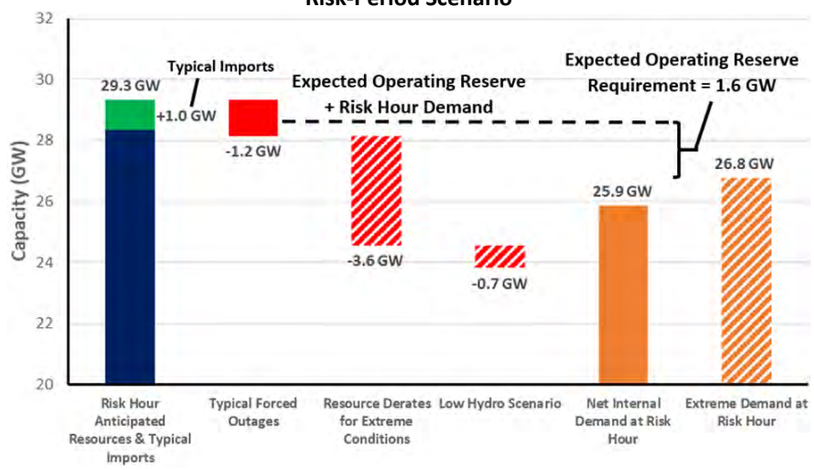
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios studied.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at 7:00 p.m. local time as solar PV output is diminished and demand remains high

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Low Hydro Scenario: Reduced hydro availability resulting from drought conditions

Data Concepts and Assumptions

The table below explains data concepts and important assumptions used throughout this assessment.

General Assumptions
• Reliability of the interconnected BPS is comprised of both adequacy and operating reliability:
▪ Adequacy is the ability of the electricity system to supply the aggregate electric power and energy requirements of the electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
▪ Operating reliability is the ability of the electricity system to withstand sudden disturbances such as electric short-circuits or unanticipated loss of system components.
• The reserve margin calculation is an important industry planning metric used to examine future resource adequacy.
• All data in this assessment is based on existing federal, state, and provincial laws and regulations.
• Differences in data collection periods for each assessment area should be considered when comparing demand and capacity data between year-to-year seasonal assessments.
• *2021 Long-Term Reliability Assessment* data has been used for most of this 2022 summer assessment period augmented by updated load and capacity data.
• A positive net transfer capability would indicate a net importing assessment area; a negative value would indicate a net exporter.
Demand Assumptions
• Electricity demand projections, or load forecasts, are provided by each assessment area.
• Load forecasts include peak hourly load[7] or total internal demand for the summer and winter of each year.[8]
• Total internal demand projections are based on normal weather (50/50 distribution[9]) and are provided on a coincident[10] basis for most assessment areas.
• Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour.
Resource Assumptions
Resource planning methods vary throughout the North American BPS. NERC uses the categories below to provide a consistent approach for collecting and presenting resource adequacy. Because the electrical output of variable energy resources (e.g., wind, solar) depends on weather conditions, their contribution to reserve margins and other on-peak resource adequacy analysis is less than their nameplate capacity.

[7] *Glossary of Terms* used in NERC Reliability Standards

[8] The summer season represents June–September and the winter season represents December–February.

[9] Essentially, this means that there is a 50% probability that actual demand will be higher and a 50% probability that actual demand will be lower than the value provided for a given season/year.

[10] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval; this is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year. SERC and FRCC calculate total internal demand on a noncoincidental basis.

Anticipated Resources:

- **Existing-Certain Capacity**: Included in this category are commercially operable generating unit or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the summer season: unit must have a firm capability and have a power purchase agreement with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or where energy-only markets exist, unit must be a designated market resource eligible to bid into the market.
- **Tier 1 Capacity Additions**: This category includes capacity that either is under construction or has received approved planning requirements.
- **Net Firm Capacity Transfers (Imports minus Exports)**: This category includes transfers with firm contracts.

Prospective Resources: Includes all anticipated resources plus the following:

Existing-Other Capacity: Included in this category are commercially operable generating units or portions of generating units that could be available to serve load for the period of peak demand for the season but do not meet the requirements of existing-certain.

Reserve Margin Descriptions

Planning Reserve Margin: This is the primary metric used to measure resource adequacy; it is defined as the difference in resources (anticipated or prospective) and net internal demand then divided by net internal demand and shown as a percentage.

Reference Margin Level: The assumptions and naming convention of this metric vary by assessment area. The Reference Margin Level can be determined using both deterministic and probabilistic (based on a 0.1/year loss of load study) approaches. In both cases, this metric is used by system planners to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing a Reference Margin Level is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increase demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, a Reference Margin Level is established by a state, provincial authority, ISO/RTO, or other regulatory body. In some cases, the Reference Margin Level is a requirement. Reference Margin Levels may be different for the summer and winter seasons. If a Reference Margin Level is not provided by an assessment area, NERC applies 15% for predominately thermal systems and 10% for predominately hydro systems.

Seasonal Risk Scenario Chart Description

Each assessment area performed an operational risk analysis that was used to produce the seasonal risk scenario charts in the **Regional Assessments Dashboards**. The chart presents deterministic scenarios for further analysis of different resource and demand levels: The left blue column shows anticipated resources, and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand and the extreme summer peak demand—both determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources, such as the following:

- Reductions for typical generation outages (i.e., maintenance and forced, not already accounted for in anticipated resources)
- Reductions that represent additional outage or performance derating by resource type for extreme, low-probability conditions (e.g., drought condition impacts on hydroelectric generation, low-wind scenario affecting wind generation, fuel supply limitations, or extreme temperature conditions that result in reduced thermal generation output)
- Additional capacity resources that represent quantified capacity from operational procedures, if any, that are made available during scarcity conditions

Not all assessment areas have the same categories of adjustments to anticipated resources. Furthermore, each assessment area determined the adjustments to capacity based on methods or assumptions that are summarized below the chart. Methods and assumptions differ by assessment area and may not be comparable.

The chart enables evaluation of resource levels against levels of expected operating reserve requirement and the forecasted demand. Furthermore, the effects from extreme events can also be examined by comparing resource levels after applying extreme-scenario derates and/or extreme summer peak demand.

Resource Adequacy

The Anticipated Reserve Margin, which is based on available resource capacity, is a metric used to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecast peak demand.[11] Large year-to-year changes in anticipated resources or forecast peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. All assessment areas have sufficient Anticipated Reserve Margins to meet or exceed their Reference Margin Level for the 2022 summer as shown in **Figure 9**.

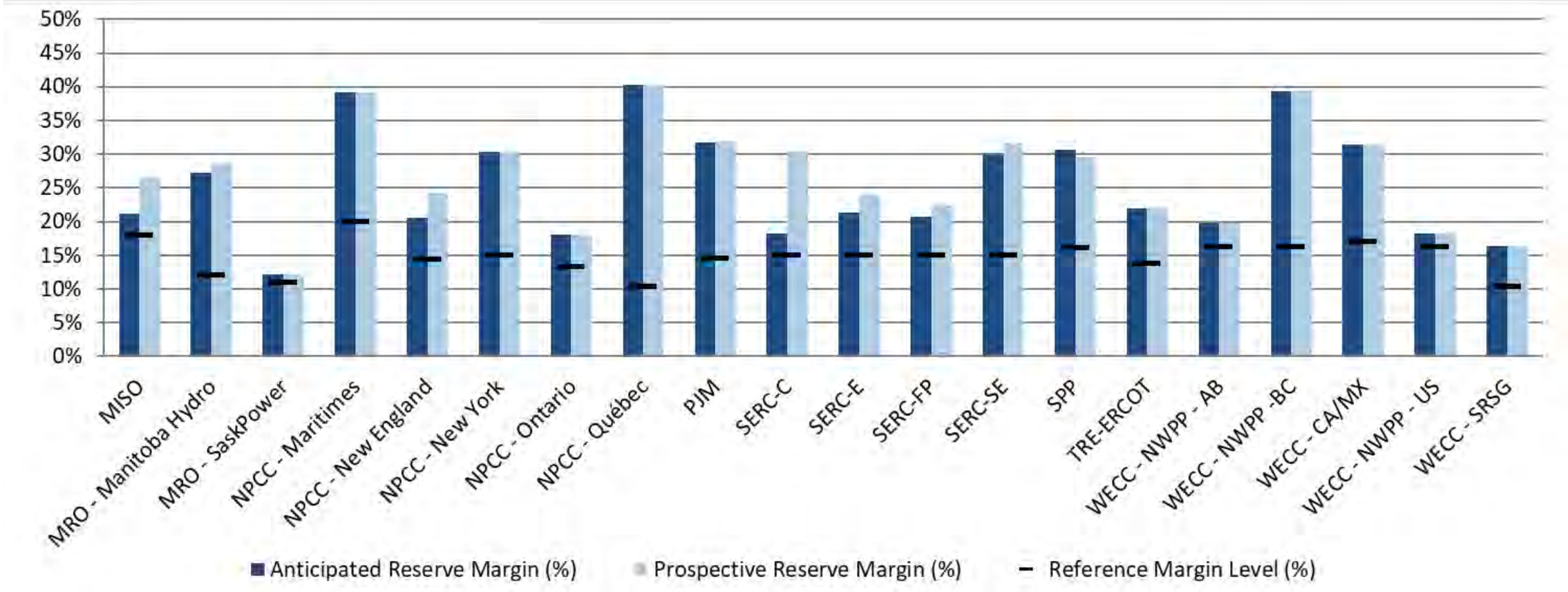
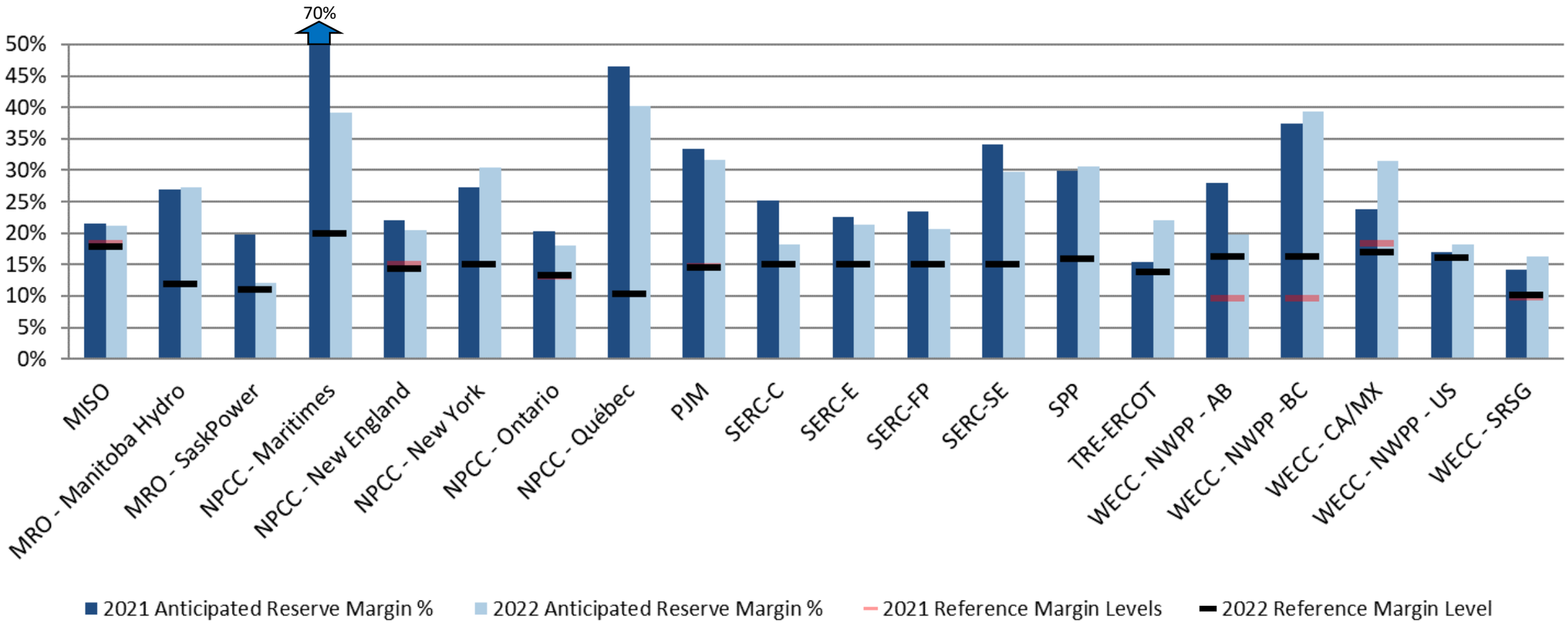


Figure 9: Summer 2022 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[11] Generally, anticipated resources include generators and firm capacity transfers that are expected to be available to serve load during electrical peak loads for the season. Prospective resources are those that could be available but do not meet criteria to be counted as anticipated resources. Refer to the **Data Concepts and Assumptions** section for additional information on Anticipated/Prospective Reserve Margins, anticipated/prospective resources, and Reference Margin Levels.

Changes from Year-to-Year

Figure 10 provides the relative change in the forecast Anticipated Reserve Margins from the 2021 summer to the 2022 summer. A significant decline can indicate potential operational issues that emerge between reporting years. MRO-SaskPower, NPCC-Maritimes, NPCC-Québec, SERC-C, and WECC-AB have noticeable reductions in anticipated resources with MRO-SaskPower close to falling below its Reference Margin Level for the 2022 summer. MRO-SaskPower will rely on demand response and transfers from neighbors during a higher load scenario to avoid load interruption. The lower Anticipated Reserve Margins for NPCC-Maritimes, NPCC-Québec, SERC-C, and WECC-AB do not present reliability concerns on peak for this upcoming summer. Additional details for each assessment area are provided in the Data Concepts and Assumptions and Regional Assessments Dashboards sections.



Note: The areas that only have one bar have the same Reference Margin Level for both years.

Figure 10: Summer 2021 and Summer 2022 Anticipated Reserve Margins Year-to-Year Change

Net Internal Demand

The changes in forecasted Net Internal Demand for each assessment area are shown in Figure 11.[12] Assessment areas develop these forecasts based on historic load and weather information as well as other long-term projections.

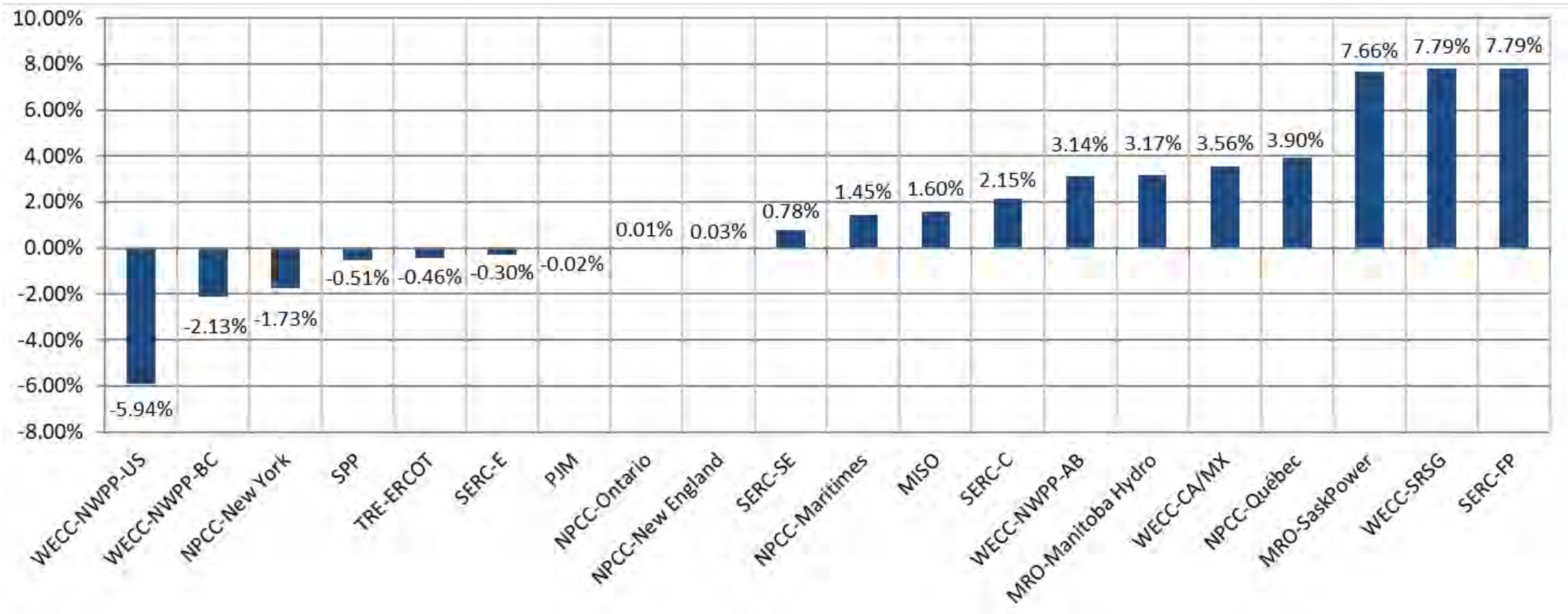


Figure 11: Change in Net Internal Demand: Summer 2021 Forecast Compared to Summer 2022 Forecast

[12] Changes in modeling and methods may also contribute to year-to-year changes in forecasted net internal demand projections.

Demand and Resource Tables

Peak demand and supply capacity data for each assessment area are provided below (in alphabetical order).

MISO Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	122,398	124,506	1.7%
Demand Response: Available	6,038	6,287	4.1%
Net Internal Demand	116,360	118,220	1.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	138,464	141,844	2.4%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	2,979	1,353	-54.6%
Anticipated Resources	141,443	143,197	1.2%
Existing-Other Capacity	633	669	5.7%
Prospective Resources	146,586	149,756	2.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	21.6%	21.1%	-0.5
Prospective Reserve Margin	26.0%	26.7%	0.7
Reference Margin Level	18.3%	17.9%	-0.4

MRO-SaskPower Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,400	3,656	7.5%
Demand Response: Available	60	60	0.0%
Net Internal Demand	3,340	3,596	7.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	3,863	3,743	-3.1%
Tier 1 Planned Capacity	13.5	0	-100.0%
Net Firm Capacity Transfers	125	290	132.0%
Anticipated Resources	4,002	4,033	0.8%
Existing-Other Capacity	0	0	-
Prospective Resources	4,002	4,033	0.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	19.8%	12.2%	-7.6
Prospective Reserve Margin	19.8%	12.2%	-7.6
Reference Margin Level	11.0%	11.0%	0.0

MRO-Manitoba Hydro Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	2,965	3,059	3.2%
Demand Response: Available	0	0	-
Net Internal Demand	2,965	3,059	3.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,173	5,523	6.8%
Tier 1 Planned Capacity	186	186	0.0%
Net Firm Capacity Transfers	-1,596	-1,816	13.8%
Anticipated Resources	3,763	3,893	3.4%
Existing-Other Capacity	37	44	18.8%
Prospective Resources	3,800	3,937	3.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.9%	27.3%	0.4
Prospective Reserve Margin	28.2%	28.7%	0.5
Reference Margin Level	12.0%	12.0%	0.0

NPCC-Maritimes Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,479	3,475	-0.1%
Demand Response: Available	305	255	-16.4%
Net Internal Demand	3,174	3,220	1.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,448	4,419	-18.9%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-57	64	-212.3%
Anticipated Resources	5,391	4,483	-16.8%
Existing-Other Capacity	0	0	-
Prospective Resources	5,391	4,483	-16.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	69.8%	39.2%	-30.6
Prospective Reserve Margin	69.8%	39.2%	-30.6
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New England Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	25,244	25,300	0.2%
Demand Response: Available	434	483	11.3%
Net Internal Demand	24,810	24,817	0.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	29,065	28,626	-1.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,208	1,292	7.0%
Anticipated Resources	30,273	29,918	-1.2%
Existing-Other Capacity	1115	911	-18.3%
Prospective Resources	31,388	30,829	-1.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.0%	20.6%	-1.4
Prospective Reserve Margin	26.5%	24.2%	-2.3
Reference Margin Level	15.0%	14.3%	-0.7

NPCC-Ontario Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	22,500	22,546	0.2%
Demand Response: Available	621	666	7.2%
Net Internal Demand	21,879	21,880	0.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	26,217	25,648	-2.2%
Tier 1 Planned Capacity	22	24	10.9%
Net Firm Capacity Transfers	80	150	87.5%
Anticipated Resources	26,319	25,822	-1.9%
Existing-Other Capacity	0	0	-
Prospective Resources	26,319	25,822	-1.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.3%	18.0%	-2.3
Prospective Reserve Margin	20.3%	18.0%	-2.3
Reference Margin Level	13.2%	13.3%	0.1

NPCC-New York Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	32,333	31,765	-1.8%
Demand Response: Available	1,199	1,170	-2.4%
Net Internal Demand	31,134	30,595	-1.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	37,805	37,431	-1.0%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,816	2,465	35.7%
Anticipated Resources	39,621	39,896	0.7%
Existing-Other Capacity	0	0	-
Prospective Resources	39,621	39,896	0.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.3%	30.4%	3.1
Prospective Reserve Margin	27.3%	30.4%	3.1
Reference Margin Level	15.0%	15.0%	0.0

NPCC-Québec Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	21,436	22,271	3.9%
Demand Response: Available	0	0	-
Net Internal Demand	21,436	22,271	3.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	33,380	33,542	0.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-1,995	-2,304	15.5%
Anticipated Resources	31,385	31,238	-0.5%
Existing-Other Capacity	0	0	-
Prospective Resources	31,385	31,238	-0.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	46.4%	40.3%	-6.1
Prospective Reserve Margin	46.4%	40.3%	-6.1
Reference Margin Level	10.4%	10.3%	-0.1

PJM Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	149,224	148,938	-0.2%
Demand Response: Available	8,779	8,527	-2.9%
Net Internal Demand	140,445	140,411	0.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	183,572	184,837	0.7%
Tier 1 Planned Capacity	2400	10	-99.6%
Net Firm Capacity Transfers	1,460	124	-91.5%
Anticipated Resources	187,431	184,971	-1.3%
Existing-Other Capacity	0	0	-
Prospective Resources	188,891	185,095	-2.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	33.5%	31.7%	-1.8
Prospective Reserve Margin	34.5%	31.8%	-2.7
Reference Margin Level	14.7%	14.9%	0.2

SERC-East Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	42,680	42,883	0.5%
Demand Response: Available	970	1,298	33.8%
Net Internal Demand	41,710	41,585	-0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	50,539	49,380	-2.3%
Tier 1 Planned Capacity	0	486	-
Net Firm Capacity Transfers	562	612	8.9%
Anticipated Resources	51,101	50,478	-1.2%
Existing-Other Capacity	766	1,097	43.2%
Prospective Resources	51,867	51,575	-0.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.5%	21.4%	-1.1
Prospective Reserve Margin	24.4%	24.0%	-0.4
Reference Margin Level	15.0%	15.0%	0.0

SERC-Central Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	40,341	41,267	2.3%
Demand Response: Available	1,744	1,841	5.6%
Net Internal Demand	38,597	39,426	2.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	47,987	47,424	-1.2%
Tier 1 Planned Capacity	154	0	-100.0%
Net Firm Capacity Transfers	172	-795	-561.6%
Anticipated Resources	48,314	46,629	-3.5%
Existing-Other Capacity	4290	4,808	12.1%
Prospective Resources	52,604	51,437	-2.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	25.2%	18.3%	-6.9
Prospective Reserve Margin	36.3%	30.5%	-5.8
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	48,710	52,172	7.1%
Demand Response: Available	3,030	2,932	-3.2%
Net Internal Demand	45,680	49,240	7.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	55,351	56,571	2.2%
Tier 1 Planned Capacity	0	2,540	-
Net Firm Capacity Transfers	1,007	300	-70.2%
Anticipated Resources	56,358	59,411	5.4%
Existing-Other Capacity	0	847	-
Prospective Resources	56,358	60,258	6.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	23.4%	20.7%	-2.7
Prospective Reserve Margin	23.4%	22.4%	-1.0
Reference Margin Level	15.0%	15.0%	0.0

SERC-Southeast Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	46,631	47,258	1.3%
Demand Response: Available	1,671	1,946	16.5%
Net Internal Demand	44,960	45,312	0.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	61,263	59,828	-2.3%
Tier 1 Planned Capacity	142	1,514	964.9%
Net Firm Capacity Transfers	-1,115	-2,524	126.4%
Anticipated Resources	60,290	58,818	-2.4%
Existing-Other Capacity	783	859	9.7%
Prospective Resources	61,073	59,677	-2.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	34.1%	29.8%	-4.3
Prospective Reserve Margin	35.8%	31.7%	-4.1
Reference Margin Level	15.0%	15.0%	0.0

SPP Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	52,249	52,040	-0.4%
Demand Response: Available	606	658	8.6%
Net Internal Demand	51,643	51,382	-0.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	66,600	67,245	1.0%
Tier 1 Planned Capacity	300	0	-100.0%
Net Firm Capacity Transfers	186	-144	-177.6%
Anticipated Resources	67,086	67,101	0.0%
Existing-Other Capacity	0	0	-
Prospective Resources	66,539	66,554	0.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	29.9%	30.6%	0.7
Prospective Reserve Margin	28.8%	29.5%	0.7
Reference Margin Level	16.0%	16.0%	0.0

Texas RE-ERCOT Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	77,144	77,317	0.2%
Demand Response: Available	2,341	2,856	22.0%
Net Internal Demand	74,803	74,461	-0.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	80,569	89,603	11.2%
Tier 1 Planned Capacity	5489	1,199	-78.2%
Net Firm Capacity Transfers	210	20	-90.5%
Anticipated Resources	86,268	90,822	5.3%
Existing-Other Capacity	0	0	-
Prospective Resources	86,296	90,850	5.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	15.3%	22.0%	6.7
Prospective Reserve Margin	15.4%	22.0%	6.6
Reference Margin Level	13.75%	13.75%	0.0

WECC-NWPP-AB Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	10,886	11,228	3.1%
Demand Response: Available	0	0	-
Net Internal Demand	10,886	11,228	3.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	12,205	11,926	-2.3%
Tier 1 Planned Capacity	1723	1,082	-37.2%
Net Firm Capacity Transfers	0	437	-
Anticipated Resources	13,928	13,445	-3.5%
Existing-Other Capacity	0	0	-
Prospective Resources	13,928	13,445	-3.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.9%	19.7%	-8.2
Prospective Reserve Margin	27.9%	19.7%	-8.2
Reference Margin Level	9.7%	10.1%	0.4

WECC-NWPP-BC Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	8,264	8,088	-2.1%
Demand Response: Available	0	0	-
Net Internal Demand	8,264	8,088	-2.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	11,178	11,266	0.8%
Tier 1 Planned Capacity	185	3	-98.4%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	11,363	11,269	-0.8%
Existing-Other Capacity	0	0	-
Prospective Resources	11,363	11,269	-0.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	37.5%	39.3%	1.8
Prospective Reserve Margin	37.5%	39.3%	1.8
Reference Margin Level	9.7%	16.3%	6.5

WECC-CA/MX Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	55,409	57,269	3.4%
Demand Response: Available	922	844	-8.4%
Net Internal Demand	54,487	56,425	3.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	63,396	70,791	11.7%
Tier 1 Planned Capacity	3358	3,381	0.7%
Net Firm Capacity Transfers	686	0	-100.0%
Anticipated Resources	67,440	74,172	10.0%
Existing-Other Capacity	0	0	-
Prospective Resources	67,440	74,172	10.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	23.8%	31.5%	7.7
Prospective Reserve Margin	23.8%	31.5%	7.7
Reference Margin Level	18.4%	16.9%	-1.5

WECC-SRSG Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	24,751	26,720	8.0%
Demand Response: Available	332	399	20.0%
Net Internal Demand	24,419	26,321	7.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	26,850	28,249	5.2%
Tier 1 Planned Capacity	188	1,369	628.2%
Net Firm Capacity Transfers	866	1,002	15.7%
Anticipated Resources	27,904	30,620	9.7%
Existing-Other Capacity	0	0	-
Prospective Resources	27,904	30,620	9.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	14.3%	16.3%	2.0
Prospective Reserve Margin	14.3%	16.3%	2.0
Reference Margin Level	9.8%	10.2%	0.4

WECC-NWPP-US Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	67,117	63,214	-5.8%
Demand Response: Available	1,087	1,104	1.5%
Net Internal Demand	66,030	62,110	-5.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	70,069	70,154	0.1%
Tier 1 Planned Capacity	1,002	798	-20.4%
Net Firm Capacity Transfers	6,139	2,517	-59.0%
Anticipated Resources	77,210	73,469	-4.8%
Existing-Other Capacity	0	0	-
Prospective Resources	77,210	73,469	-4.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	16.9%	18.3%	1.4
Prospective Reserve Margin	16.9%	18.3%	1.4
Reference Margin Level	14.3%	16.1%	1.8

Variable Energy Resource Contributions

Because the electrical output of variable energy resources (e.g., wind, solar) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity. The table below shows the capacity contribution of existing wind and solar resources at the peak demand hour for each assessment area. Resource contributions are also aggregated by Interconnection and across the entire BPS. For NERC's analysis of risk periods after peak demand (i.e., U.S. assessment areas in WECC), lower contributions of solar resources are used because output is diminished during evening periods.

BPS Variable Energy Resources by Assessment Area									
	Wind			Solar			Hydro		
Assessment Area / Interconnection	Nameplate Wind	Expected Wind	Expected Share of Nameplate (%)	Nameplate Solar	Expected Solar	Expected Share of Nameplate (%)	Nameplate Hydro	Expected Hydro	Expected Share of Nameplate (%)
MISO	28,893	4,478	16%	2,441	1,221	50%	2,440	2,361	97%
MRO-Manitoba Hydro	259	41	16%	-	-	0%	5,917	5,255	89%
MRO-SaskPower	628	88	14%	-	-	0%	864	784	91%
NPCC-Maritimes	1,212	326	27%	2	-	0%	1,315	1,183	90%
NPCC-New England	1,421	201	14%	2,638	773	29%	4,059	2,812	69%
NPCC-New York	2,336	314	13%	76	35	46%	5,949	5,138	86%
NPCC-Ontario	4,943	751	15%	478	66	14%	8,918	4,716	53%
NPCC-Québec	3,820	-	0%	10	-	0%	41,346	32,789	79%
PJM	10,876	1,659	15%	4,852	2,878	64%	3,022	3,022	100%
SERC-Central	964	4	0%	450	287	64%	5,005	3,381	68%
SERC-East	-	-	0%	724	716	99%	3,052	3,002	98%
SERC-Florida Peninsula	-	-	0%	5,246	3,220	61%	-	-	0%
SERC-Southeast	-	-	0%	4,053	3,500	86%	3,242	3,288	101%
SPP	31,325	7,276	23%	306	245	80%	5,456	5,297	97%
Texas RE-ERCOT	35,454	9,423	27%	11,515	9,327	81%	571	475	83%
WECC-AB	3,177	232	7%	1,063	684	64%	894	378	42%
WECC-BC	717	142	20%	2	1	49%	16,378	10,115	62%
WECC-CA/MX	8,946	1,754	20%	19,457	13,634	70%	13,985	7,691	55%
WECC-NWPP-US	19,410	3,312	17%	7,479	4,735	63%	41,705	21,564	52%
WECC-NWPP-SRSG	3,245	516	16%	3,219	2,511	78%	3,532	2,765	78%
EASTERN INTERCONNECTION	82,856	14,425	17%	21,476	13,836	64%	50,846	41,776	82%
QUÉBEC INTERCONNECTION	3,820	-	0%	10	-	0%	41,346	32,789	79%
TEXAS INTERCONNECTION	35,454	9,423	27%	11,515	9,327	81%	571	475	83%
WECC INTERCONNECTION	35,495	5,956	17%	31,220	21,565	69%	76,494	42,513	56%
TOTAL:	157,626	29,804	19%	64,221	44,729	70%	169,257	117,554	69%

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2023 Summer Reliability Assessment

May 2023



2023 Summer Reliability Assessment Video

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Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of NERC and the six Regional Entities, is a highly reliable, resilient, and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entities as shown on the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators (TO/TOP) participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

About this Assessment

NERC's *2023 Summer Reliability Assessment* (*SRA*) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming summer season. In addition, the *SRA* presents peak electricity demand and supply changes and highlights any unique regional challenges or expected conditions that might affect the reliability of the BPS. The reliability assessment process is a coordinated reliability evaluation between the NERC Reliability Assessment Subcommittee, the Regional Entities, and NERC staff with demand and resource projections obtained from the assessment areas. This report reflects an independent assessment by NERC and the ERO Enterprise and is intended to inform industry leaders, planners, operators, and regulatory bodies so that they are better prepared to take necessary actions to ensure BPS reliability. This report also provides an opportunity for the industry to discuss plans and preparations to ensure reliability for the upcoming summer period.

Key Findings

NERC's annual SRA covers the upcoming four-month (June–September) summer period. This assessment provides an evaluation of generation resource and transmission system adequacy as well as energy sufficiency to meet projected summer peak demands and operating reserves. This includes a deterministic evaluation of data submitted for peak net demand hour and peak risk hour as well as results from recently updated probabilistic analyses. Additionally, this assessment identifies potential reliability issues of interest and regional topics of concern. While the scope of this seasonal assessment is focused on the upcoming summer, the key findings are consistent with risks and issues that NERC has highlighted in the *2022 Long-Term Reliability Assessment* and other earlier reliability assessments and reports.

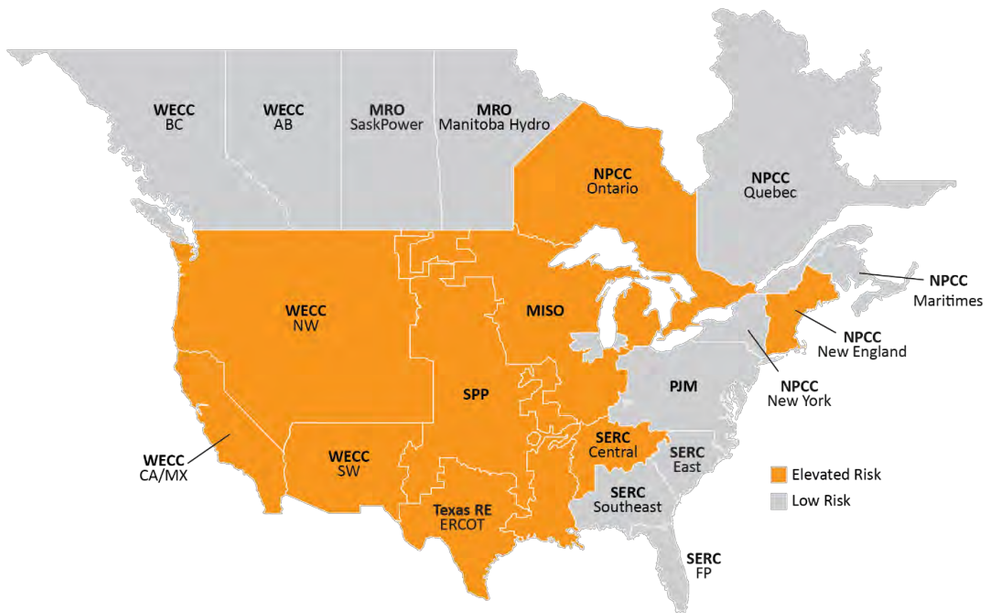
The following findings are NERC's and the ERO Enterprise's independent evaluation of electricity generation and transmission capacity as well as potential operational concerns that may need to be addressed for the 2023 summer.

Resource Adequacy Assessment and Energy Risk Analysis

All areas are assessed as having adequate anticipated resources for normal summer peak load and conditions (see **Figure 1**). However, the following areas face risks of electricity supply shortfalls during periods of more extreme summer conditions. This determination of elevated risk is based on analysis of plausible scenarios, including 90/10 demand forecasts and historic high outage rates as well as low wind, solar photovoltaic (PV), or hydro energy conditions:

- **Midcontinent ISO (MISO):** The risk of being unable to meet reserve requirements at peak demand this summer in MISO is lower than in 2022 due to additional firm import commitments and lower peak demand forecast. MISO is expected to have sufficient resources, including firm imports, for normal summer peak demand. Wind generator performance during periods of high demand is a key factor in determining whether there is sufficient electricity supply on the system to maintain reliability. MISO can face challenges in meeting above-normal peak demand if wind generator energy output is lower than expected. Furthermore, the need for external (non-firm) supply assistance during more extreme demand levels will depend largely on wind energy output. Results of MISO's capacity auction have not been released at the time of this assessment, and these could change MISO's firm resources for the summer.
- **NPCC-New England:** Anticipated resources in New England are projected to be lower than in 2022 but are expected to remain sufficient for meeting operating reserve requirements at normal peak demand. Operating procedures for obtaining emergency resources or non-firm supplies from neighboring areas are likely to be needed during more extreme demand or low resource conditions.
- **NPCC-Ontario:** Planned nuclear outage for refurbishment have reduced the electricity supply resources serving the province. Additionally, load growth is contributing to a constrained transmission network during high-demand conditions that may not be able to deliver sufficient supply to the Windsor-Essex area in the southwest part of the province. Additional generator outages or extreme demand can lead to reserve shortages and a need to seek non-firm imports. Ontario could potentially see a significant increase in reliance on imports this summer under both normal peak (50/50) and extreme (90/10) demand scenarios.
- **SERC-Central**: Compared to the summer of 2022, forecasted peak demand has risen by over 950 MW while growth in anticipated resources has been flat. The assessment area is expected to have sufficient supply for normal peak demand while demand-side management or other operating mitigations can be expected for above-normal demand or high generator-outage conditions.
- **Southwest Power Pool (SPP):** Reserve margins have also fallen in SPP as a result of increasing peak demand and declining anticipated resources. Like MISO, the energy output of SPP's wind generators during periods of high demand is a key factor in determining whether there is sufficient electricity supply on the system. SPP can face energy challenges in meeting extreme peak demand or managing periods of thermal or hydro generator outages if wind resource energy output is below normal.
- **Texas (ERCOT):** The area is experiencing strong growth in both resources and forecasted demand. ERCOT added over 4 GW of new solar PV nameplate capacity to the ERCOT grid since 2022. Additionally, load reductions from dispatchable demand response programs have grown by over 18% to total 3,380 MW. ERCOT's peak demand forecast has also risen by 6% as a result of economic growth. Resources are adequate for peak demand of the average summer; however, dispatchable generation may not be sufficient to meet reserves during an extreme heat-wave that is accompanied by low winds.
- **U.S. Western Interconnection:** Resources across the area are sufficient to support normal peak demand. However, wide-area heat events can expose the WECC assessment areas of California/Mexico (CA/MX), Northwest (NW), and Southwest (SW) to risk of energy supply shortfall as each area relies on regional transfers to meet demand at peak and the late afternoon to evening hours when energy output from the area's vast solar PV resources are diminished. Within the Western Interconnection, entities are planning to install over 2 GW of new battery energy storage systems, which can help reduce energy risks from resource variability. Wildfire risks to the transmission network, which often accompany these wide-area heat events, can limit electricity transfers and result in localized load shedding.

All other areas have sufficient resources to manage normal summer peak demand and are at low risk of energy shortfalls from more extreme demand or generation outage conditions. Anticipated Reserve Margins meet or surpass the Reference Margin Level, indicating that planned resources in these areas are adequate to manage the risk of a capacity deficiency under normal conditions. Furthermore, based on risk scenario analysis in these areas, resources and energy appear adequate. **Figure 1** below summarizes the risk status for all assessment areas.



Seasonal Risk Assessment Summary	
High	Potential for insufficient operating reserves in normal peak conditions
Elevated	Potential for insufficient operating reserves in above-normal conditions
Low	Sufficient operating reserves expected

Figure 1: Summer Reliability Risk Area Summary

Other Reliability Issues

- **Stored supplies of natural gas and coal are at high levels, but industry is monitoring for potential generator fuel delivery risks.** The natural gas supply and infrastructure is vitally important to electric grid reliability, even as renewable generation satisfies more of our energy needs. Fuel supply and delivery infrastructure must be capable of meeting the ramp rates of natural-gas-fired generators as they balance the system when solar generation output declines. Likewise, owners and operators of some coal-fired generators in the U.S. Southeast report challenges in arranging coal replenishment due to mine closures and transport delays. Consequently, some Balancing Authorities (BA) continue to employ coal-conservation measures that began in late 2022 in order to maintain sufficient stocks for peak months.

- **New environmental rules that restrict power plant emissions will limit the operation of coal-fired generators in 23 states, including Nevada, Utah, and several states in the Gulf Coast, mid-Atlantic, and Midwest.** The U.S. Environmental Protection Agency's (EPA) Good Neighbor Plan, finalized on March 15, 2023, ensures that affected states meet the Clean Air Act's "Good Neighbor" requirements by reducing pollution that significantly contributes to problems attaining and maintaining the EPA's health-based air quality standard[1] for ground-level ozone (i.e., smog) in downwind states.[2] Coal and natural-gas-fired generators in states affected by the Good Neighbor Plan will likely meet tighter emissions restrictions primarily by limiting hours of operation in this first year of implementation rather than through adding emissions control equipment. RCs in summer-peaking areas typically are not able to authorize extended outages to upgrade systems during this summer season in order to ensure sufficient resources for high demand. The final rule approved by the EPA includes provisions designed to give grid owners and operators flexibility to help maintain reliability, including allowance-trading mechanisms. Consequently, RCs, BAs, and GOs will need to be vigilant for emissions rule constraints that affect generator dispatchability and the potential need for emission allowance trades or waivers to meet high demand or low resource conditions. State regulators and industry should have protocols in place at the start of summer for managing emergent requests.

- **Low inventories of replacement distribution transformers could slow restoration efforts following hurricanes and severe storms.** The electric industry continues to face a shortage of distribution transformers as a result of production not keeping pace with demand. A survey by the American Public Power Association revealed that many utilities have low levels of emergency stocks that are used for responding to natural disasters and catastrophic events.[3]

[1] This standard is known as the 2015 Ozone National Ambient Air Quality Standards (NAAQS)
[2] https://www.epa.gov/csapr/good-neighbor-plan-2015-ozone-naaqs#summary
[3] https://www.publicpower.org/periodical/article/appa-survey-members-shows-distribution-transformer-production-not-meeting-demand

Asset sharing programs used by utilities provide visibility and voluntary equipment sharing to maximize resources; however, electricity customers may experience delayed restoration of power following storms as crews must work to obtain new equipment. New efficiency standards for distribution transformers proposed by the U.S. Department of Energy could further exacerbate the transformer supply shortages.[4]

- **Supply chain issues present maintenance and summer preparedness challenges and are delaying some new resource additions.** Difficulties in obtaining sufficient labor, material, and equipment as a result of broad economic factors has affected preseason maintenance of transmission and generation facilities in North America. These supply chain issues have led some owners and operators to delay or cancel maintenance activities that are typically performed to ensure facilities are ready for summer conditions. Additionally, GOs in some areas that were preparing to interconnect new generation are facing delays that will prevent some from being available to meet expected peak summer demand. This includes areas in the U.S. Southeast and the U.S. part of the Western Interconnection (see **Regional Assessments Dashboards** for details). These supply chain issues can exacerbate concerns in elevated risk areas (**Figure 1**) and add challenges to operators across the BPS. Should project delays emerge, affected GOs and TOs must communicate changes to BAs, TOPs, and RCs so that impacts are understood and steps are taken to reduce risks of capacity deficiencies or energy shortfalls.
- **Winter precipitation is expected to improve the water supply for hydro generation in parts of the U.S. West, but low water levels on major reservoirs remain a concern for electricity generation.** Significant amounts of rainfall and high elevation snow are expected to help replenish reservoirs and maintain river flows that provide energy for most of California's hydroelectric facilities. However, reservoirs at the largest hydro facilities in the U.S. West, including Washington's Grand Coulee Dam and the Hoover Dam on the Arizona-Nevada border, remain at historic low levels, potentially limiting hydroelectric energy output. Power from these plants is used throughout the U.S. Western Interconnection.
- **Unexpected tripping of wind and solar PV resources during grid disturbances continues to be a reliability concern.** NERC has analyzed multiple large-scale disturbances on the BPS that involved widespread loss of inverter-based resources (IBR). In 2021 and 2022, the Texas Interconnection experienced widespread IBR loss events, like those previously observed in the California area. Similarly, four additional solar PV loss events occurred between June and August 2021 in California. In 2022, ERCOT required GOs to submit mitigation plans, and corrective measures are being implemented in 2023. In March 2023, NERC issued the *Inverter-Based Resource Performance Issues Alert* to GOs of Bulk Electric System (BES) solar PV generating resources.[5] As a Level 2 alert, it contains recommended actions for GOs of grid-connected solar PV resources, including steps to coordinate protection and controller settings, so that the resources will reliably operate during grid disturbances.
- **Curtailment of electricity transfers to areas in need during periods of high regional demand is a growing reliability concern.** During energy emergencies and periods of transmission system congestion, RCs and BAs may curtail area transfers for various reasons using established procedures and protocols. While the curtailments alleviate an issue in one part of the system, they can contribute to supply shortages or effect local transmission system operations in another area. Two recent extreme temperature events highlight the effect of transfer curtailments on area supply needs during energy emergencies. During the September 2022 wide-area heat dome, a BA in the WECC-SW assessment area declared an energy emergency when the neighboring assessment area, California Independent System Operator (CAISO), curtailed transfers in order to meet the high demand within their own area. During Winter Storm Elliott, firm exports were curtailed from PJM during a period of widespread energy emergencies in the U.S. Eastern Interconnection.

  For the summer of 2023, several areas identified as having capacity or energy risks are relying on imports of electricity supplies. These areas include MISO, NPCC-Ontario, SERC-Central, and the assessment areas in the U.S. Western Interconnection. A wide-area heat event that severely affects regional demand or generator availability presents an added concern in areas that are dependent on imports for managing high electricity demand.
- **In addition to the risk items identified in the Key Findings, resource outages will continue to present challenges in many areas during "near-peak" demand conditions that occur in spring and fall.** Many parts of North America experience elevated temperatures that extend beyond the summer (June–September) months into periods when BPS equipment owners and operators historically scheduled outages for maintenance. Increasingly, BAs are facing resource constrained periods during shoulder months as unseasonable temperatures coincide with generator unavailability. Careful attention to long-term weather forecasts and the potential for unusual heat patterns in the shoulder months is important to inform the need for more conservative outage coordination periods.

[4] https://www.energy.gov/articles/doe-proposes-new-efficiency-standards-distribution-transformers

[5] https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC%20Alert%20R-2023-03-14-01%20Level%202%20-%20Inverter-Based%20Resource%20Performance%20Issues.pdf

Recommendations

To reduce the risk of electricity shortfalls on the BPS this summer, NERC recommends the following:

- RCs, BAs, and TOPs in the elevated risk areas identified previously in the key findings should take the following actions:
  - Review seasonal operating plans and the protocols for communicating and resolving potential supply shortfalls in anticipation of potentially extreme demand levels
  - Employ conservative generation and transmission outage coordination procedures commensurate with long-range weather forecasts to ensure adequate resource availability
  - Engage state or provincial regulators and policymakers to prepare for efficient implementation of demand side management mechanisms called for in operating plans
- GOs with solar PV resources should implement recommendations in the inverter-based resource performance issues alert that NERC issued in March 2023.
- RCs, BAs, and GOs in states affected by the new Good Neighbor Plan should be familiar with its provisions for ensuring electric reliability and have protocols in place to act to preserve generation resources when necessary to support periods of high demand. State regulators and industry should have protocols in place at the start of summer for managing emergent requests.

Discussion

Summer Temperature and Drought Forecasts

Peak electricity demand in most areas is directly influenced by temperature. Weather officials are expecting above normal temperatures for much of the United States while Canada is largely expected to see normal or below-normal average temperatures (see **Figure 2**). In addition, drought conditions continue across much of the western half of North America, resulting in unique challenges to area electricity supplies and potential impacts on demand.[6] Assessment area load forecasts account for many years of historical demand data, often up to 30 years, to predict summer peak demand and prepare for more extreme conditions. Above average seasonal temperatures can contribute to high peak demand as well as an increase in forced outages for generation and some BPS equipment. Effective preseason maintenance and preparations are particularly important to BPS reliability in severe or prolonged periods of above-normal temperatures.

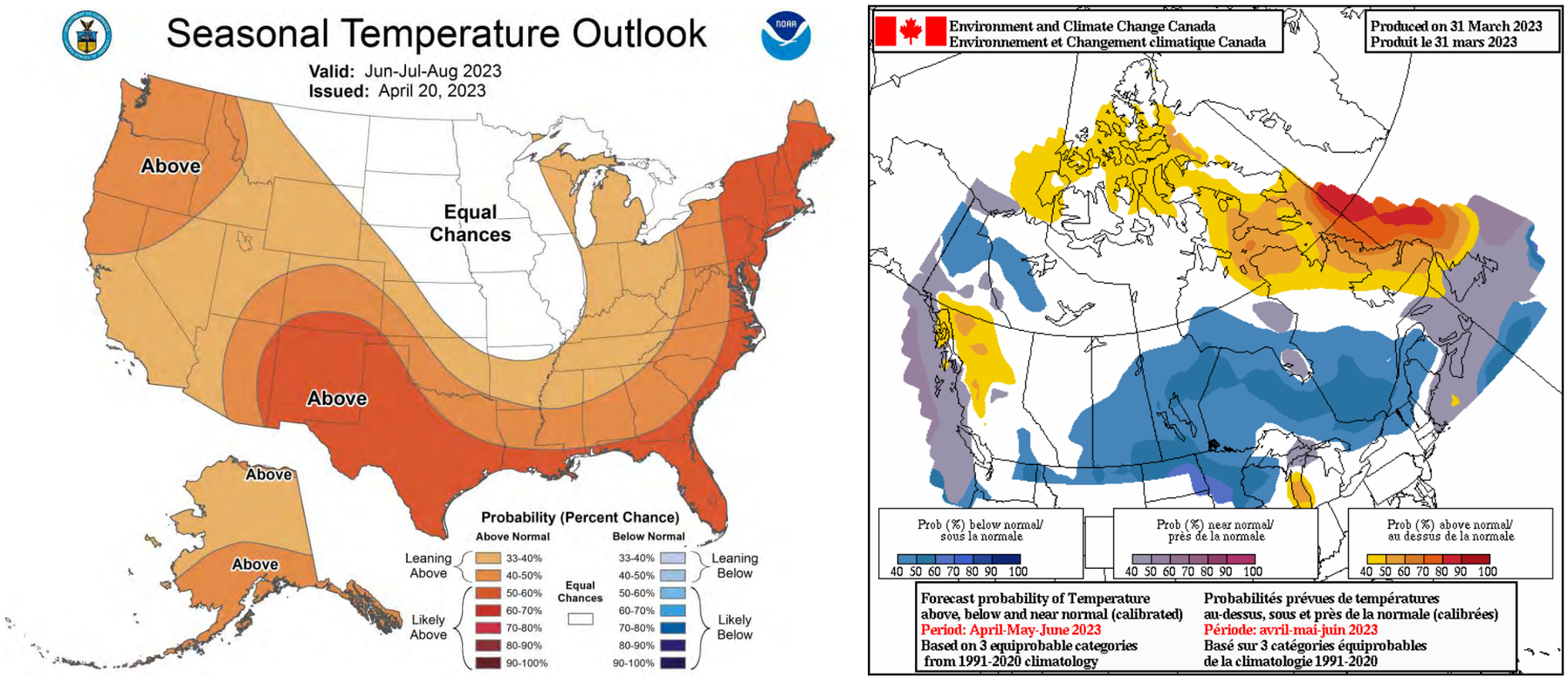


Figure 2: United States and Canada Summer Temperature Outlook[7]

[6] See North American Drought Monitor: https://www.ncdc.noaa.gov/temp-and-precip/drought/nadm/maps

[7] Seasonal forecasts obtained from U.S. National Weather Service and Natural Resources Canada: https://www.cpc.ncep.noaa.gov/products/predictions/long_range/ and https://weather.gc.ca/saisons/prob_e.html

Wildfire Risk Potential and BPS Impacts

Normal or below-normal fire risk is projected for much of the U.S. West at the beginning of the summer; in contrast, Florida, West Texas, and Central Canada project above-normal fire risks for the beginning of summer (see **Figure 3**). BPS operation can be impacted in areas where wildfires are active as well as areas where there is heightened risk of wildfire ignition due to weather and ground conditions. Above normal fire risk is projected for much of Canada throughout the summer.

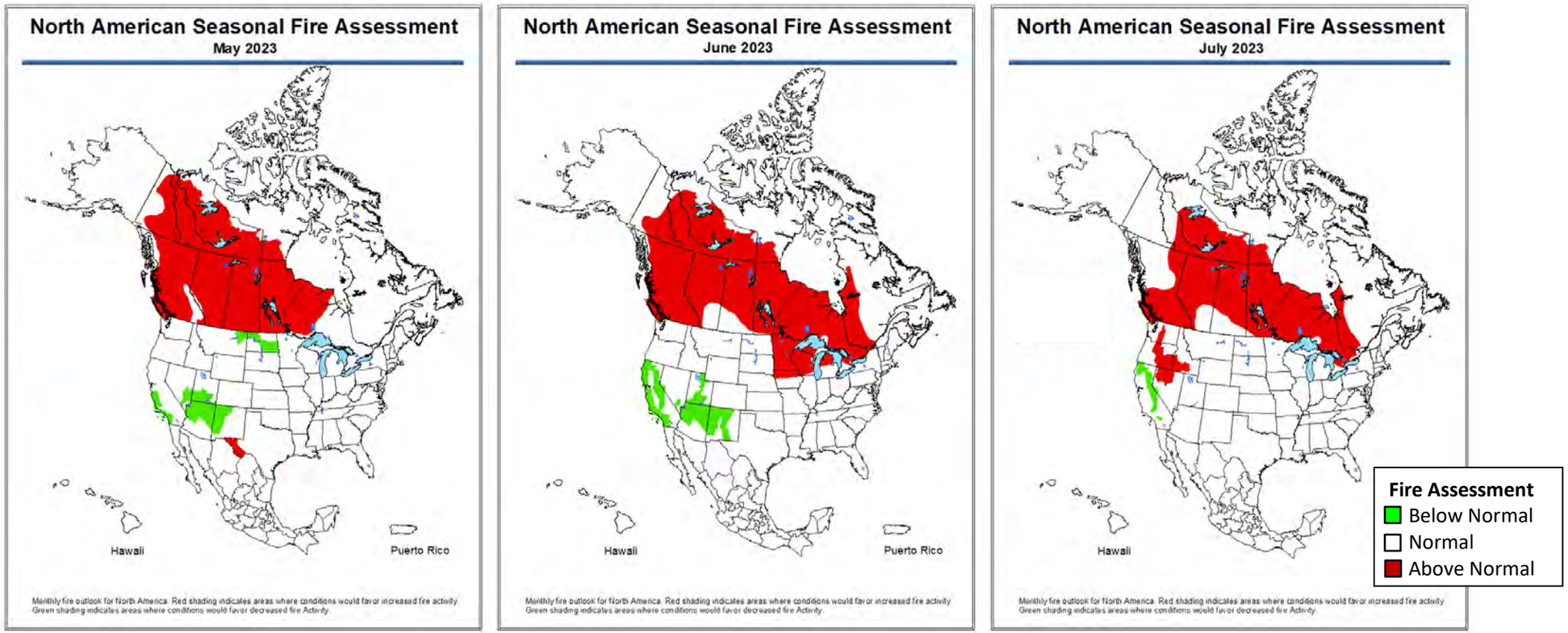


Figure 3: North American Seasonal Fire Assessment for May through July 2023[8]

Wildfire prevention planning in California and some states in the U.S. Northwest include power shut-off programs in high fire-risk areas. When conditions warrant implementing these plans, power lines (including transmission-level lines) may be preemptively de-energized in high fire-risk areas to prevent wildfire ignitions. Other wildfire risk mitigation activities include implementing enhanced vegetation management, equipment inspections, system hardening, and added situational awareness measures. In January 2021, the ERO published the *Wildfire Mitigation Reference Guide*[9] to promote preparedness within the North American electric power industry and share the experiences and practices from utilities in the Western Interconnection.

[8] *See North American Seasonal Fire Assessment and Outlook*, May 2023. Subsequent updates at this link will include August and September: https://www.predictiveservices.nifc.gov/outlooks/NA_Outlook.pdf

[9] See the NERC *Wildfire Mitigation Reference Guide*, January 2021: https://nerc.com/comm/RSTC/Documents/Wildfire%20Mitigation%20Reference%20Guide_January_2021.pdf

Risk Assessments of Resource and Demand Scenarios

Seasonal risk scenarios for each assessment area are presented in the **Regional Assessments Dashboards** section. The on-peak reserve margin and seasonal risk scenario chart in each dashboard provide potential summer peak demand and resource condition information. The reserve margins on the right side of the dashboard pages provide a comparison to the previous year's assessment. The seasonal risk scenario charts present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. The assessment areas determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized in the seasonal risk scenario charts; see the **Data Concepts and Assumptions** for more information about these dashboard charts.

The seasonal risk scenario charts can be expressed in terms of reserve margins: In **Table 1**, each assessment area's Anticipated Reserve Margins are shown alongside the reserve margins for a typical generation outage scenario (where applicable) and the extreme demand and resource conditions in their seasonal risk scenario.

Highlighted in **orange** are the areas identified as having resource adequacy or energy risks for the summer in the **Key Findings** section's discussion. The typical outages reserve margin is comprised of anticipated resources minus the capacity that is likely to be in maintenance or forced outage at peak demand. If the typical maintenance or forced outage margin is the same as the Anticipated Reserve Margin, it is because an assessment area has already factored typical outages into the anticipated resources. The extreme conditions margin includes all components of the scenario and represents the most severe operating conditions of an area's scenario. Note that any reserve margin below zero indicates that the resources fall below demand in the scenario.

In addition to the peak demand and seasonal risk hour scenario charts, the assessment areas provided a resource adequacy risk assessment that was probability-based for the summer season. Results are included in the Highlights section of each assessment area's dashboard and summarized in the **Probabilistic Assessment** section. The risk assessments account for the hour(s) of greatest risk of resource shortfall. For most areas, the hour(s) of risk coincide with the time of forecasted peak demand; however, some areas incur the greatest risk at other times based on the varying demand and resource profiles. Various risk metrics are provided and include loss of load expectation (LOLE), loss of load hours (LOLH), expected unserved energy (EUE), and the probabilities of energy emergency alert (EEA) occurrence.

Table 1: Seasonal Risk Scenario On-Peak Reserve Margins

Assessment Area	Anticipated Reserve Margin	Anticipated Reserve Margin with Typical Outages	Anticipated Reserve Margin with Higher Demand, Outages, Derates in Extreme Conditions
MISO	23.0%	4.3%	-6.9%
MRO-Manitoba	29.1%	25.6%	13.1%
MRO-SaskPower	29.1%	12.8%	-1.9%
NPCC-Maritimes	49.7%	39.3%	20.2%
NPCC-New England	17.7%	7.0%	-3.9%
NPCC-New York	30.3%	17.0%	9.9%
NPCC-Ontario	14.0%	14.0%	8.6%
NPCC-Québec	37.1%	37.1%	37.1%
PJM	31.9%	23.4%	8.4%
SERC-Central	18.0%	9.6%	6.4%
SERC-East	19.1%	16.0%	9.0%
SERC-Florida Peninsula	26.6%	19.9%	12.8%
SERC-Southeast	39.6%	36.4%	33.8%
SPP	24.6%	14.3%	-4.0%
Texas RE-ERCOT	23.0%	16.5%	-1.6%
WECC-AB	24.8%	21.9%	8.1%
WECC-BC	28.9%	28.8%	-5.4%
WECC-CA/MX	35.0%	29.0%	-11.9%
WECC-NW	28.5%	22.5%	-12.9%
WECC-SW	19.5%	15.8%	-6.8%

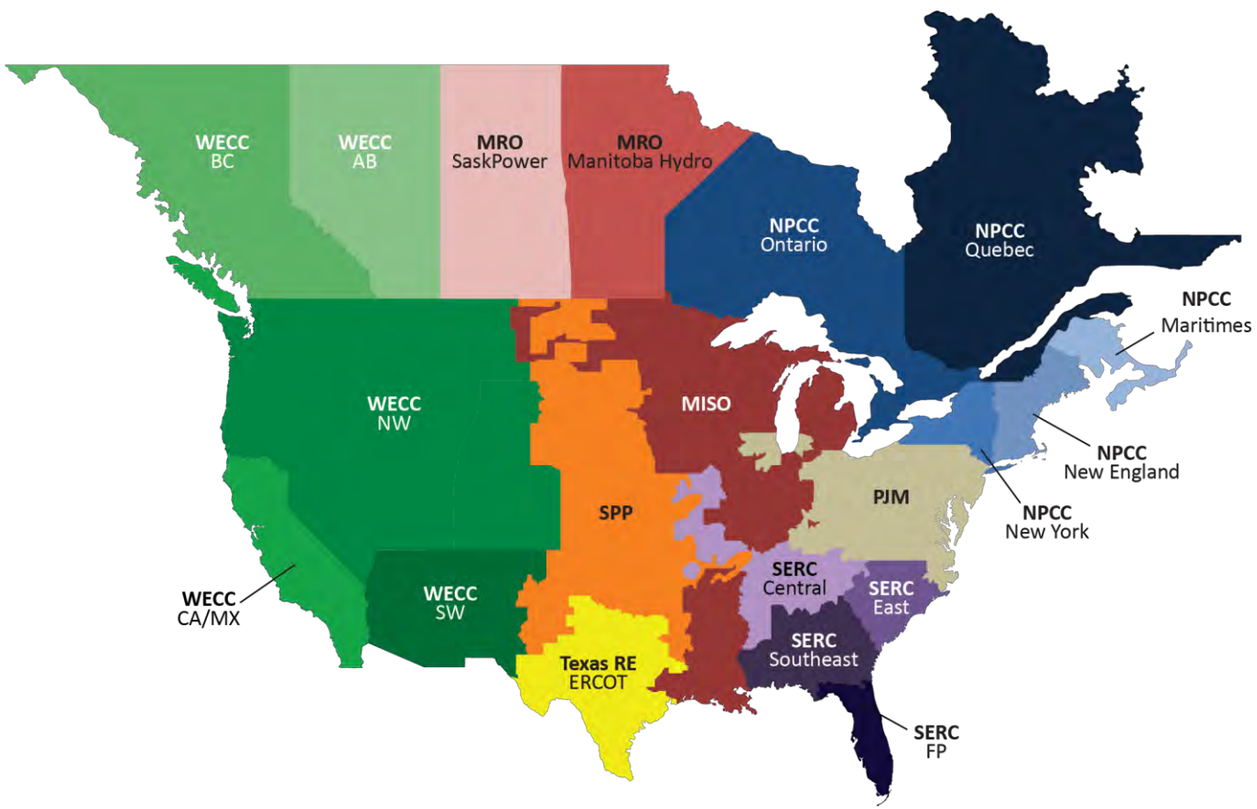
Extreme generation outages, low resource output, and peak loads similar to those experienced in wide area heat events and the heat domes experienced in western parts of North America during the last three summers are ongoing reliability risks in certain areas for the summer of 2023. When forecasted resources in an area fall below expected demand, BAs would need to employ operating mitigations or EEA to obtain the capacity and energy necessary to meet extreme peak demands. **Table 2** describes the various EEA levels and the circumstances for each.

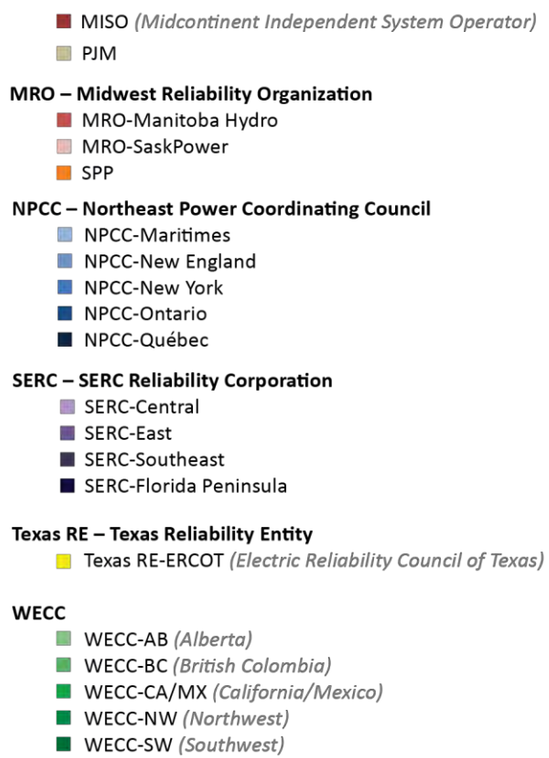
Table 2: Energy Emergency Alert Levels

EEA Level	Description	Circumstances
EEA 1	All available generation resources in use	• The BA is experiencing conditions where all available generation resources are committed to meet firm load, firm transactions, and reserve commitments and is concerned about sustaining its required contingency reserves. • Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
EEA 2	Load management procedures in effect	• The BA is no longer able to provide its expected energy requirements and is an energy deficient BA. • An energy deficient BA has implemented its operating plan(s) to mitigate emergencies. • An energy deficient BA is still able to maintain minimum contingency reserve requirements.
EEA 3	Firm Load interruption is imminent or in progress	• The energy deficient BA is unable to meet minimum contingency reserve requirements.

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six Regional Entities on an assessment area basis. Guidelines and definitions are in the **Data Concepts and Assumptions** table. On-Peak Reserve Margin bar charts show the Anticipated Reserve Margin compared to a Reference Margin Level that is established for the areas to meet resource adequacy criteria. Prospective Reserve Margins can give an indication of additional on-peak capacity but are not used for assessing adequacy. The operational risk analysis shown in the following regional assessments dashboard pages provides a deterministic scenario for understanding how various factors that affect resources and demand can combine to impact overall resource adequacy. For each assessment area, there is a risk-period scenario graphic; the left blue column shows anticipated resources (from the **Demand and Resource Tables**), and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand (from the **Demand and Resource Tables**) and the extreme summer peak demand determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources. Adjustments may include reductions for typical generation outages (maintenance and forced not already accounted for in anticipated resources) and additions that represent the quantified capacity from operational tools (if any) that are available during scarcity conditions but have not been accounted for in the SRA reserve margins. Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The cumulative effects from extreme events are also factored in through additional resource derates or low-output scenarios. In addition, results from a probability-based resource adequacy assessment are shown in the Highlights section of each dashboard. Methods varied by assessment area and provided further insights into the risk conditions forecasted for the summer period.







MISO

MISO is a not-for profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency. MISO manages energy, reliability, and operating reserve markets that consist of 36 local BA and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three Regional Entities, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

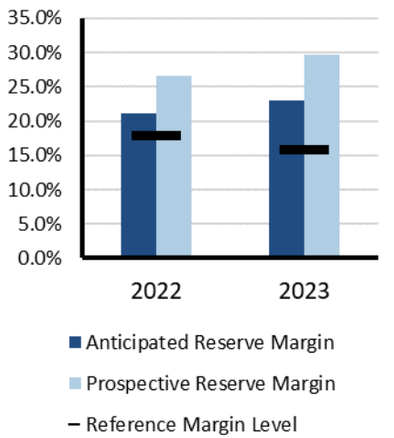
Highlights

- Demand forecasts and preliminary resource data indicate that MISO is at risk of operating reserve shortfalls during periods of high demand or low resource output. MISO's resources are projected to be lower than in the summer of 2022 while net internal demand has also decreased. Firm transmission imports for this summer have significantly increased; this has resulted in a higher Anticipated Reserve Margin (ARM) of 23% (on an installed capacity basis) compared to 21% last summer. MISO's capacity auction has not concluded at the time of this assessment, which could lead to some change to MISO's firm resources for the summer.
- MISO conducted its annual probabilistic LOLE analysis and determined a 2023 Reference Margin Level (RML) of 15.9% results in an LOLE of 1 day in 10 years. MISO's RML declined from 17.9% in 2022 to 15.9% in 2023 based on the newly implemented seasonal capacity construct and associated modeling improvements that include seasonal outage rates and other enhancements. Comparing the increased ARM to the lower RML indicates improved reliability from the LOLE base case at 1 day in 10 years.
- Performance of wind generators during periods of high electricity demand is a key factor in determining whether system operators need to employ operating mitigations, such as maximum-generation declarations and energy emergencies. MISO has over 30,300 MW of installed wind capacity; however, the historically-based on-peak capacity contribution is 5,488 MW.

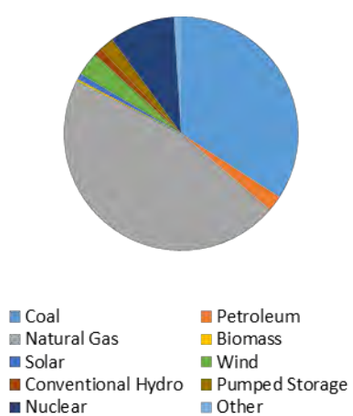
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., load modifying resources and energy transfers from neighboring systems) and EEAs. Emergency declarations that can only be called upon when available generation is at maximum capability are necessary to access load modifying resources (demand response) when operating reserve shortfalls are projected.

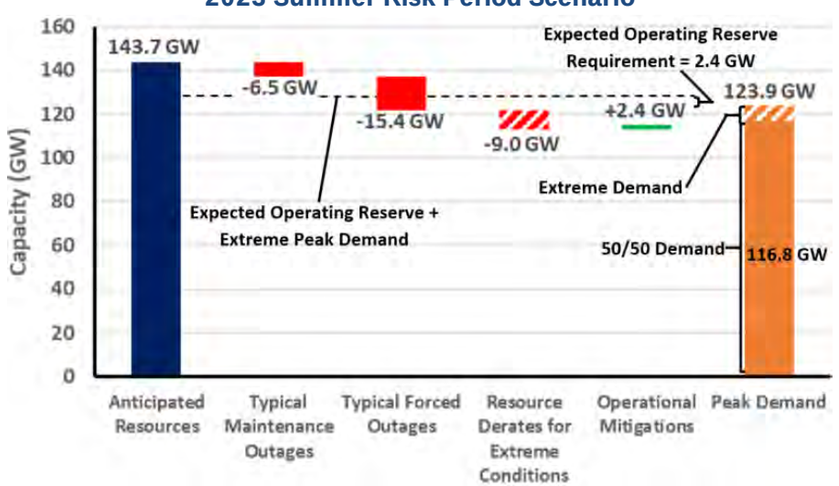
On-Peak Reserve Margin



On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

Maintenance Outages: Rolling five-year summer average of maintenance and planned outages

Forced Outages: Five-year average of all outages that were not planned

Extreme Derates: Maximum historical generation outages

Operational Mitigations: A total of 2.4 GW capacity resources available during extreme operating conditions



MRO-Manitoba Hydro

Manitoba Hydro is a provincial Crown Corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro is a leader in providing renewable energy and clean-burning natural gas Manitoba Hydro provides electricity to approximately 608,500 electric customers in Manitoba and provides approximately 293,000 customers with natural gas in Southern Manitoba. The service area is the province of Manitoba which is 251,000 square miles Manitoba Hydro is winter peaking. Manitoba Hydro is its own Planning Coordinator (PC) and BA. Manitoba Hydro is a coordinating member of MISO. MISO is the RC for Manitoba Hydro.

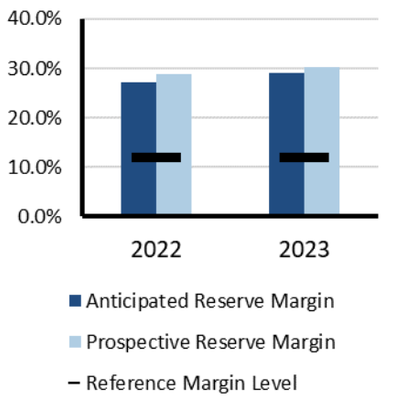
Highlights

- Manitoba Hydro is not anticipating any operational challenges and/or emerging reliability issues in its assessment area for the summer of 2023.
- The Anticipated Reserve Margin for the summer of 2023 exceeds the 12% Reference Margin Level.
- Six of the seven units at Keeyask Generating Station (hydroelectric) have reached commercial operation status. The remaining unit (Keeyask Unit 6) is listed as a Tier 1 capacity resource as it is operating but awaiting official commercial operation status.
- The 2022 probabilistic work indicated the annual probabilistic indices for the Manitoba Hydro system for 2024 of 29 MWh per year of EUE. Given comparable supply and demand balance, the 2024 EUE is a reasonable estimate for all of 2023.

Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

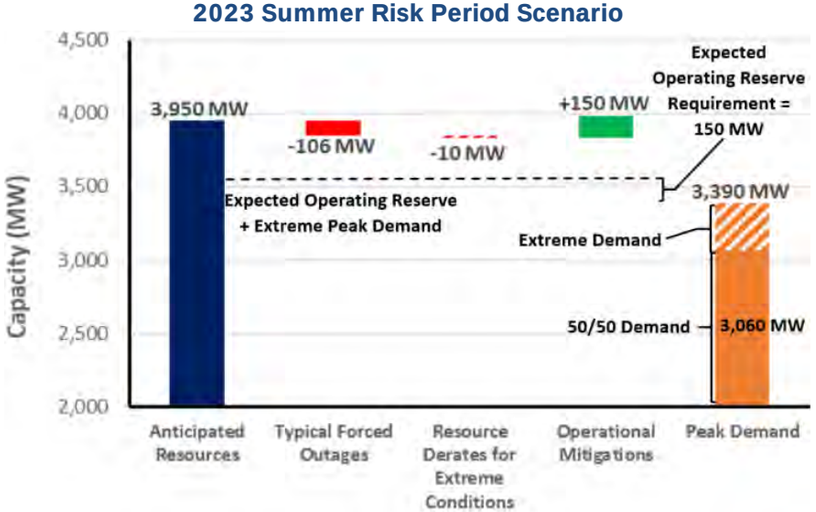
On-Peak Reserve Margin



On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: (50/50) Demand with allowance for Extreme Demand based on extreme summer weather scenario of 37 C (99 F)

Forced Outages: Typical forced outages

Extreme Derates: Summer wind capacity accreditation of 18.1% of nameplate rating based on MISO seasonal analysis

Normal hydro generation expected for this summer.

Operational Mitigations: Utilize Curtailable Rate Program to manage peak demand; utilize operating reserve if additional measures required



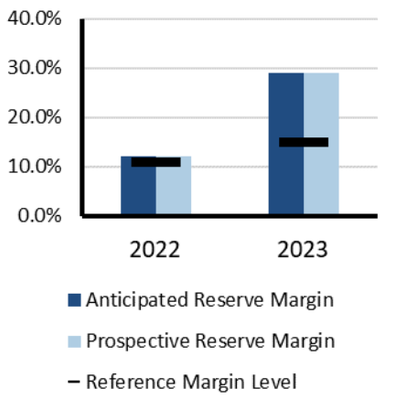
MRO-SaskPower

MRO-SaskPower is an assessment area in the Saskatchewan province of Canada. The province has a geographic area of 651,900 square kilometers (251,700 square miles) and a population of approximately 1.1 million. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the PC and RC for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan BES and its Interconnections.

Highlights

- Summer reserve margins in Saskatchewan are higher than in 2022 due to the addition of new wind resources, fewer scheduled generator outages, and lower forecasted peak demand.
- Saskatchewan is a winter-peaking region but also experiences high load in summer during extreme hot weather.
- SaskPower conducts an annual summer joint operating study with Manitoba Hydro and prepares operating guidelines for any identified issues. Inputs from the Western Area Power Administration are included in the study.
- Results from SaskPower's probabilistic analysis indicate that the expected number of hours with operating reserve deficiency for the 2023 summer season (June to September) is 0.21 hours. The month with the highest probability of EEA is September (0.07 hours). The risk of operating reserve shortage during peak load times or EEAs could increase if large generation forced outage combined with planned maintenance outages occurs during peak load times in June, July, August, and September months.
- In case of extreme electricity demand from high temperatures combined with large generation forced outages, SaskPower would use available demand response programs, short-term power transfers from neighboring utilities, and short-term load interruptions if necessary.
- The Reference Reserve Margin was updated to adequately assess energy risks, such as due to changing resource mix, and to align with NERC recommended RRM.

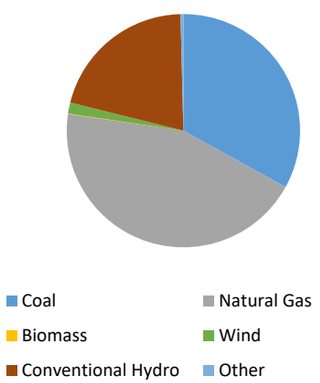
On-Peak Reserve Margin



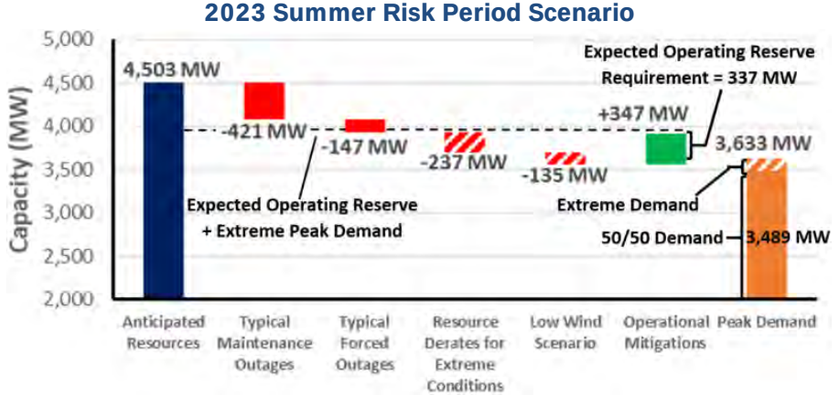
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and above-normal scenario based on peak demand with lighting and all consumer loads

Maintenance Outages: Average of planned maintenance outages for the last three summers less future planned outages (already considered in Anticipated Resources)

Forced Outages: Estimated by using SaskPower forced outage model

Extreme Derates: Estimated resources unavailable in extreme conditions

Low Wind Scenario: 33% reduction in nameplate capacity for temperatures between 35° C and 40° C

Operational Mitigations: Estimated non-firm imports and stand-by generators on 2–7 day notice



NPCC-Maritimes

The Maritimes assessment area is a winter-peaking NPCC area that contains two BAs. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, and Prince Edward Island, and the northern portion of Maine, which is radially connected to the New Brunswick power system. The area covers 58,000 square miles with a total population of 1.9 million.

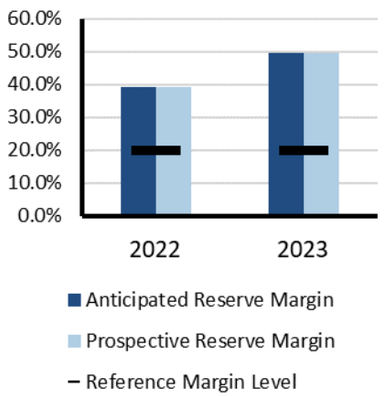
Highlights

- The Maritimes area has not identified any operational issues that are expected to impact system reliability. If an event were to occur, there are emergency operations and planning procedures in place. All of the area's declared firm capacity is expected to be operational for the summer. As part of the planning process, dual-fuel units will have sufficient supplies of heavy fuel oil on-site to enable sustained operation in the event of natural gas supply interruptions.
- Based on an NPCC Probabilistic Assessment, minimal amounts of cumulative LOLE (<0.03 days/period), LOLH (<0.11 hours/period), or EUE (<5 MWh/period) were estimated over the May–September summer period for all modeled scenarios. The Maritimes area is winter peaking. The analysis included simulation of a base case (normal 50/50 demand and expected resources) and a highest peak load scenario as well as a low-likelihood, reduced resource case. This reduced resource case considered the impacts of wind capacity being derated by half during July and August due to calm weather, natural-gas-fired units being derated by half in July and August due to supply disruptions (dual-fuel units assumed to revert to oil) as well as reduced transfer capabilities. The highest load level results were based on the two highest load levels of the seven modeled, having approximately a combined 7% chance of occurring.

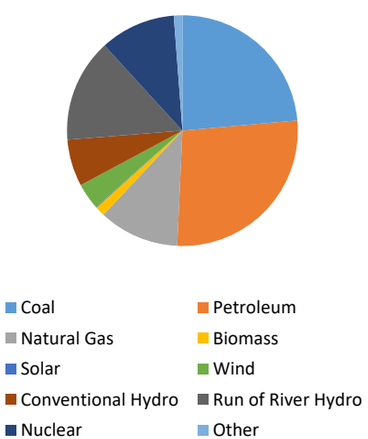
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs.

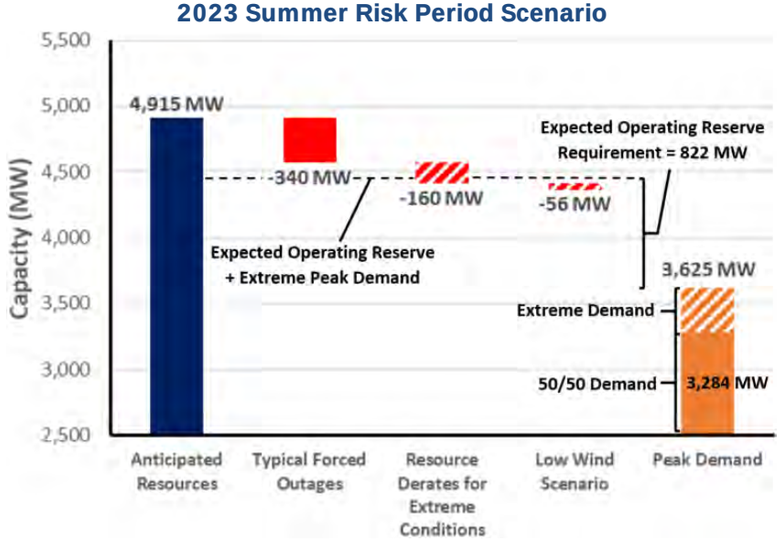
On-Peak Reserve Margin



On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (above 90/10) extreme demand forecast

Forced Outages: Based on historical operating experience

Extreme Derates: A low-likelihood scenario resulting in an additional 50% derate in the remaining capacity of both natural gas and wind resources under extreme conditions



NPCC-New England

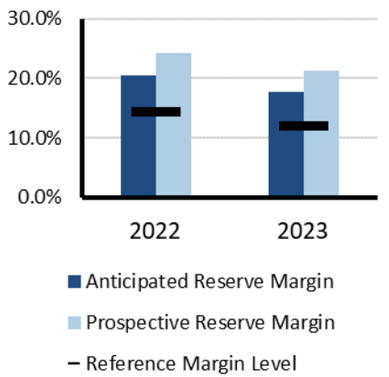
NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont that is served by ISO New England (ISO-NE) Inc. ISO-NE is a regional transmission organization that is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administration of the area's wholesale electricity markets, and management of the comprehensive planning of the regional BPS.

The New England BPS serves approximately 14.5 million customers over 68,000 square miles.

Highlights

- Reserve margins in New England are projected to be lower this summer due to less existing-certain capacity and firm imports. The New England area expects to have sufficient capacity to meet the 2023 summer peak demand forecast. As of April 4, 2023, The New England area expects to have sufficient resources to meet the 2023 summer peak demand forecast of 24,664 MW, for the weeks beginning June 4 through week beginning September 10, 2023, with the lowest projected net margin of 231 MW (0.9%) during the week of June 25, 2023. The 2023 summer demand forecast takes into account the demand reductions associated with energy efficiency, load management, behind-the-meter photovoltaic (BTM-PV) systems, and distributed generation.
- Based on an NPCC Probabilistic Assessment, ISO-NE may rely on limited use of its operating procedures that are designed to mitigate resource and energy shortages during the summer. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios except the severe low-likelihood case. This reduced resource case with the highest peak load scenario resulted in a small estimated cumulative LOLE risk (0.12 days/period) with associated LOLHs (0.4 hours/period) and EUE (175 MWh/period) with the highest risk occurring in June. This scenario is based exclusively on the two highest load levels with a 7% chance of occurring and a low resource case consisting of extended summer maintenance across NPCC and reduced imports from PJM.

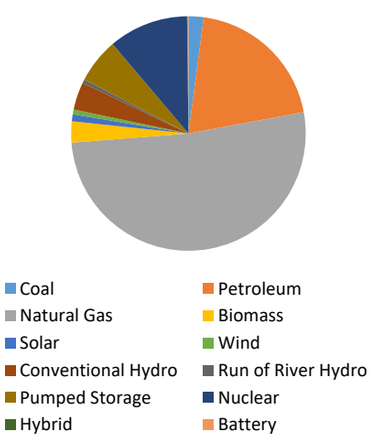
On-Peak Reserve Margin



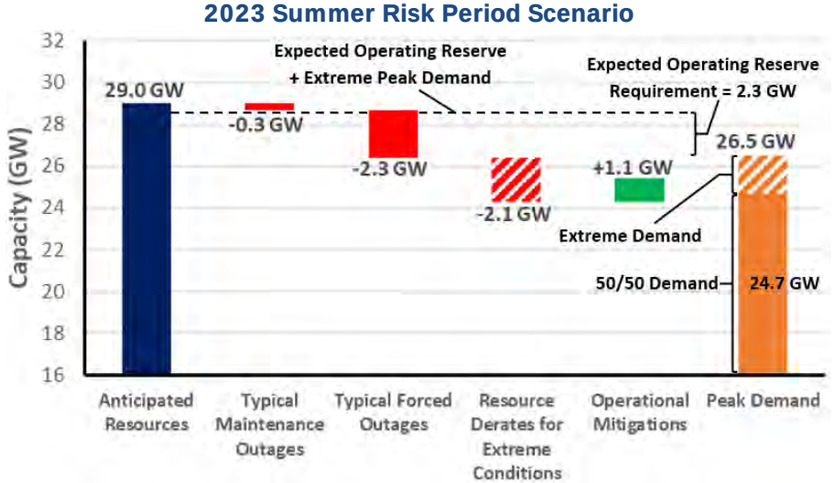
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios with local operating procedures. Extreme summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, appeals) and EEAs. As noted above, the risk of load shedding is low.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Peak net internal demand (50/50) and (90/10) extreme demand forecast

Maintenance & Forced Outages: Based on historical weekly averages

Extreme Derates: Represent a case that is beyond the (90/10) conditions based on historical observation of force outages, additional reductions for generation at risk due to operating issues at extreme hot temperatures, and other outage causes reported by generators

Operational Mitigations: Based on load and capacity relief assumed available from invocation of ISO-NE operating procedures



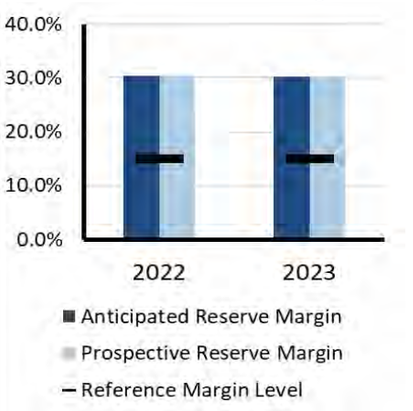
NPCC-New York

NPCC-New York is an assessment area consisting of the New York ISO (NYISO) service territory. NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. The NYISO is the only BA within the state of New York. The BPS encompasses over 11,000 miles of transmission lines, 760 power generation units, and serves 20.2 million customers. For this SRA, the established Reference Margin Level is 15%. Wind, grid-connected solar PV, and run-of-river totals were derated for this calculation. However, New York requires load-serving entities to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council. New York State Reliability Council approved the 2022–2023 IRM at 20.0%.

Highlights

- NYISO is not anticipating any operational issues in the New York control area for the upcoming summer. Adequate capacity margins are anticipated, and existing operating procedures are sufficient to handle any issues that may occur.
- A number of combustion turbine generators will be retiring before or during this summer as a result of the New York State Department of Environmental Conservation Peaker Rule. Retirements in 2023 include 16 MW of natural-gas-fired, 53 MW of oil-fired, and 558 MW of dual-fueled generation. New generation includes 556 MW of land-based wind, 90 MW of new solar PV (coming in the third quarter), and 136 MW of new offshore wind generation (coming in the third quarter). Overall, the rule is expected to lead to the retirement of approximately 1,600 MW of capacity by 2025.
- Based on an NPCC Probabilistic Assessment, NYISO may rely on limited use of its operating procedures that are designed to mitigate resource and energy shortages during the summer. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios except the severe low-likelihood case. This reduced resource case with highest peak load scenario resulted in a small estimated cumulative LOLE risk (0.5 days/period) with associated LOLH (1.1 hours/period) and EUE (525 MWh/period) with the highest risk in June and August. This scenario is based exclusively on the two highest load levels with a 7% chance of occurring and a low resource case consisting of extended summer maintenance across NPCC and reduced imports from PJM.

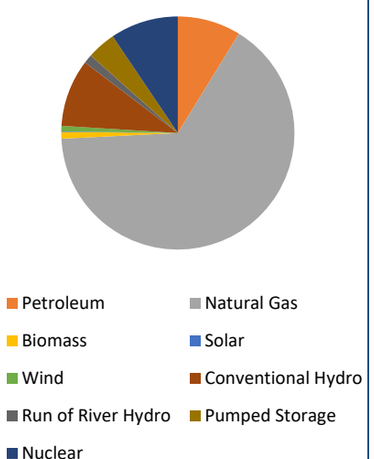
On-Peak Reserve Margin



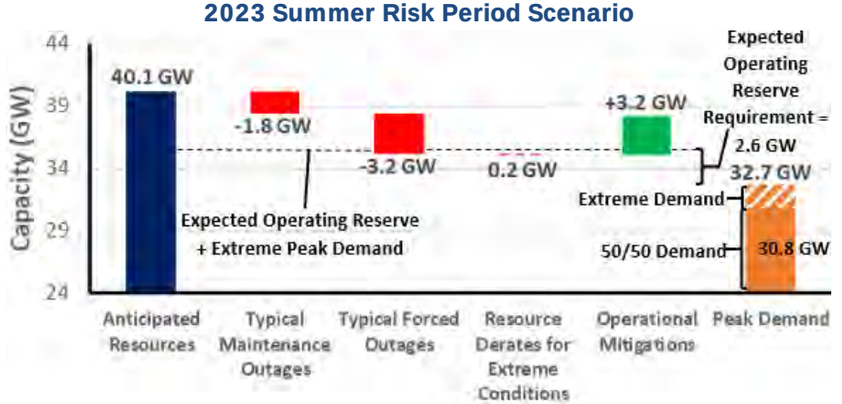
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) extreme demand forecast

Maintenance Outages:

Forced Outages: Based on historical 5-year averages

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: A total of 3.3 GW based on operational/emergency procedures in area emergency operations manual



NPCC-Ontario

NPCC-Ontario is an assessment area in the Ontario province of Canada. The Independent Electricity System Operator (IESO) is the BA for the province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of more than 14 million. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

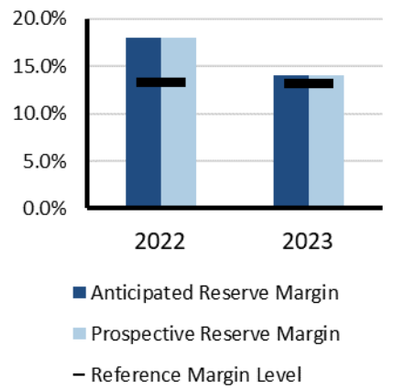
Highlights

- Ontario has entered a period during which generation and transmission outages will be increasingly difficult to accommodate. The IESO expects these conditions to persist for the foreseeable future. IESO is strongly encouraging market participants to plan ahead and coordinate with IESO to ensure planned outages can be appropriately scheduled.
- Under both normal and extreme weather conditions, Ontario may rely on imports and outage management for a significant number of weeks during the 2023 summer assessment period primarily as a result of coincident generator outages. Should market participants be unable to reschedule certain outages during this period, Ontario may have to rely on more than 2,000 MW of non-firm supply from other areas and/or additional operating actions to ensure reliability.
- Based on an NPCC Probabilistic Assessment, Ontario is expected to need only limited use of its operating procedures that are designed to mitigate resource and energy shortages during the summer. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios except the severe low-likelihood cases, which resulted in small LOLH (0.3 hours). These results model import availability and indicate that Ontario will be able to obtain the necessary supplies from neighbors over a range of most conditions, but there is a risk during extreme demand and low resource periods.
- The ongoing transmission outage at the New York–St. Lawrence interconnection continues to impact import and export capacity between Ontario and New York. This issue is expected to be resolved by the end of the fourth quarter of 2023.

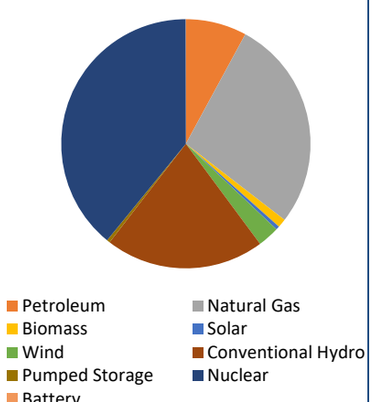
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load or extreme outage conditions could result in the need to employ operating mitigations (i.e., demand response and non-firm transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios.

On-Peak Reserve Margin



On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50 Forecast) and highest weather-adjusted daily demand based on 31 years of demand history

Extreme Derates: Derived from weather-adjusted temperature rating of thermal units and adjustments to expected hydro production for low water conditions

Operational Mitigations: Imports anticipated from neighbors during emergencies



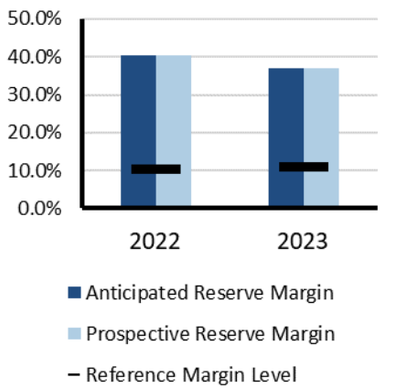
NPCC-Québec

The Québec assessment area (Province of Québec) is a winter-peaking NPCC area that covers 595,391 square miles with a population of 8 million. Québec is one of the four Interconnections in North America; it has ties to Ontario, New York, New England, and the Maritimes; consisting of either high voltage direct current ties, radial generation, or load to and from neighboring systems.

Highlights

- The Québec area forecasted summer peak demand (excluding April, May, and September) is 22,859 MW during the week of August 13, 2023, with a forecasted net margin of 7,202 MW (31.5%). No particular resource adequacy problems are forecasted, and the Québec area expects to be able to provide assistance to other areas up to the transfer capability available.
- In the Québec RC area, most transmission line, transformer, and generating unit maintenance is done during the summer period. Internal transmission outage plans are assessed to meet internal demand, firm sales, expected additional sales, and additional uncertainty margins. They should not impact inter-area transfer capabilities with neighboring systems. During the 2023 summer operating period, some maintenance outages are scheduled on the interconnections. Maintenance is coordinated with neighboring RC areas so as to leave maximum capability to summer-peaking areas.
- Based on an NPCC Probabilistic Assessment, Québec is expected to need only limited use of its operating procedures designed to mitigate resource and energy shortages during the summer. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios, including the severe low-likelihood cases.

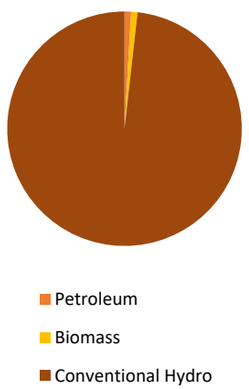
On-Peak Reserve Margin



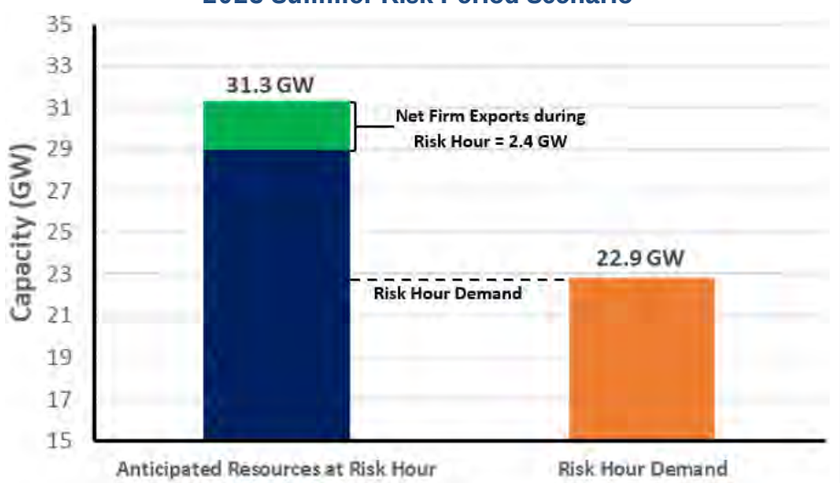
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenario: Net internal demand (50/50) and (90/10) demand forecast

Net Firm Transfers: Anticipated exports to neighbors during the risk hour



PJM

PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM serves 65 million customers and covers 369,089 square miles. PJM is a BA, PC, Transmission Planner, Resource Planner, Interchange Authority, TOP, Transmission Service Provider, and RC.

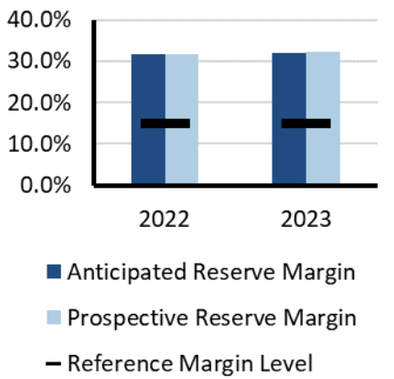
Highlights

- PJM expects no resource problems over the entire 2023 summer peak season. Installed capacity is over twice the PJM reserve requirement necessary to meet the 1-day-in-10-years LOLE criterion.
- The 2022 PJM reserve requirement study used to establish the target installed reserve margin of 14.9% analyzed a wide range of load scenarios (low, regular and extreme) as well as multiple scenarios for system-wide unavailable capacity due to forced outages, maintenance outages, and ambient derations. Due to the rather low penetration of limited and variable resources in PJM relative to PJM's peak load, the hour with most loss of load risk remains the hour with highest forecasted net peak demand.
- No other reliability issues are expected.

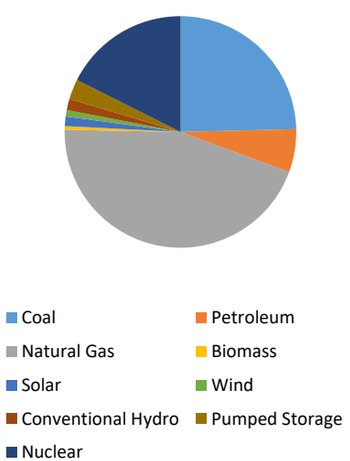
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

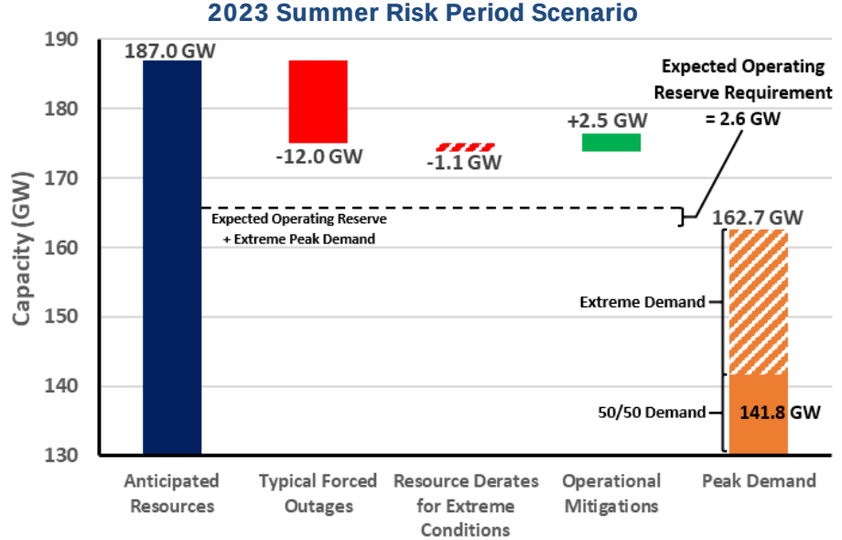
On-Peak Reserve Margin



On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Based on historical data and trending

Extreme Derates: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 2.5 GW based on operational/emergency procedures



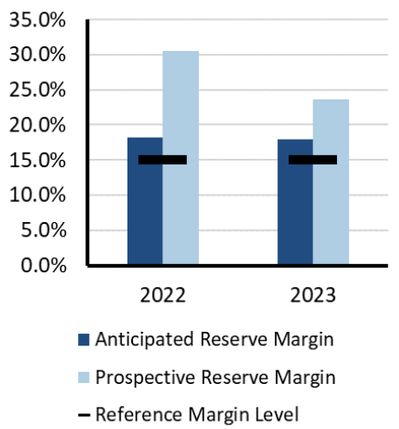
SERC-Central

SERC-Central is an assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. Historically a summer-peaking area, SERC-Central is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission (FERC) approved delegation agreements with NERC. SERC-Central is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities (PA), and 6 RCs.

Highlights

- Entities in SERC-Central have not identified any potential reliability issues for the upcoming summer season. Entities anticipate having adequate system capacity for the upcoming summer season and are equipped to address unexpected short-term issues by leveraging diverse generation portfolios and spot purchases from the power markets when necessary.
- Non-economic dispatch (out of merit) of available coal-fired generators ahead of the upcoming summer season is anticipated in order to build inventory and limit consumption of fuel and consumables for plant operations and mitigate supply and transportation challenges during the summer.
- Each entity continues to work collaboratively to ensure reliability for its area within SERC and to promote reliability and adequacy across the entire SERC Regional Entity.
- Entities continue to participate actively in the SERC Near-Term and Long-Term Working Groups among others. These working groups help the entities identify and address emerging and potential reliability impacts on transmission and resource adequacy along with transfer capability.
- Probabilistic analysis indicates negligible risk for resource shortfall. The 2022 study found negligible LOLH and EUE during summer months for a similar resource mix and demand levels.

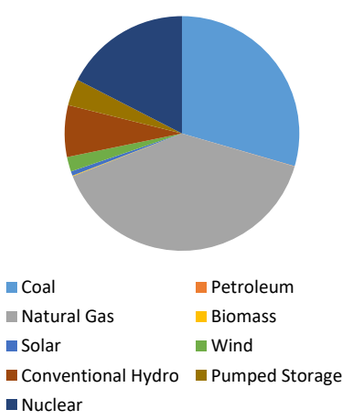
On-Peak Reserve Margin



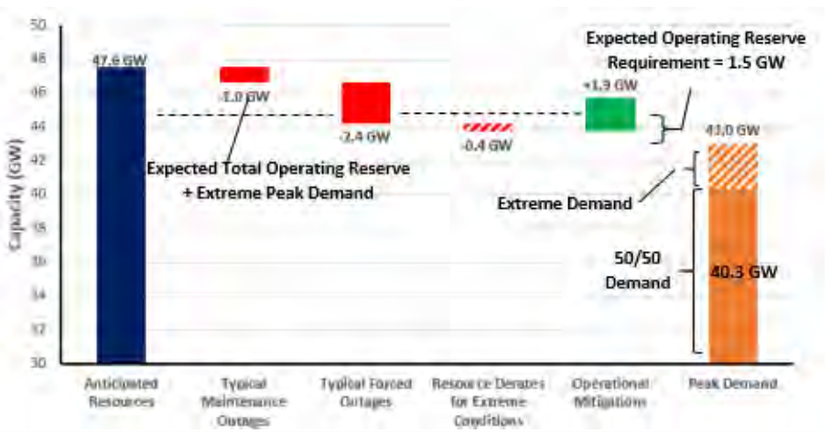
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: A total of 1.9 GW based on operational/emergency procedures



SERC-East

SERC-East is an assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina. Historically a summer-peaking area, SERC-East is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under FERC approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 PAs, and 6 RCs.

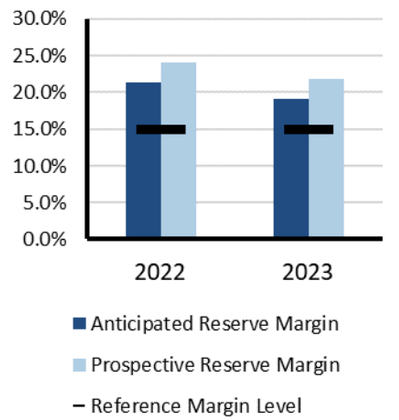
Highlights

- SERC-East is transitioning to a hybrid-peaking (both summer and winter peaking) area as solar PV reduces summer peak demand and electrification of heating drives up winter peak demand.
- Entities have not identified any emerging reliability issues or operational concerns for the upcoming summer season.
- Entities continue to perform resource studies to ensure resource adequacy to meet the summer peak demand and to maintain reliability to the system.
- Entities continue to participate actively in the SERC Near-Term and Long-Term Working Groups. These groups identify emerging and potential reliability impacts on transmission and resource adequacy along with transfer capability.
- Probabilistic analysis shows a low risk for resource shortfall during the months of July and August. The 2022 study found LOLH of 0.005 hours and EUE of 2.381 MWh during summer months for a similar resource mix and demand levels.

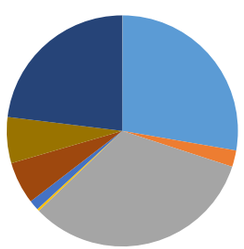
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margin

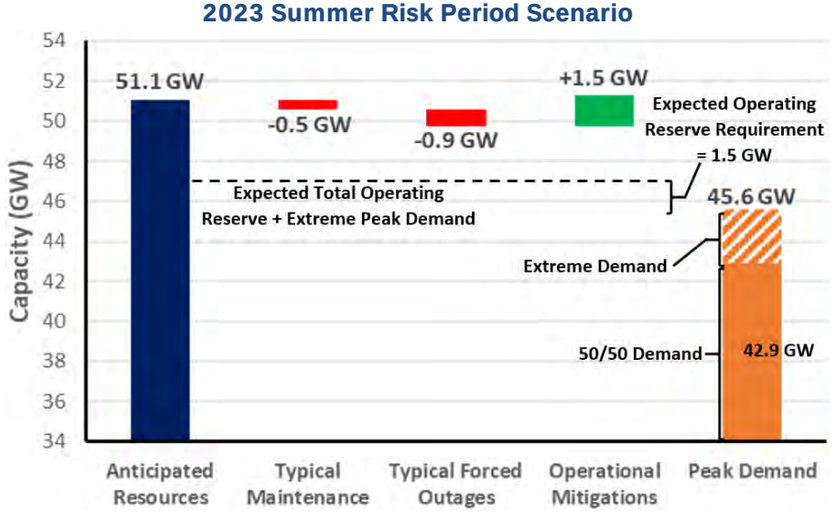


On-Peak Fuel Mix



Coal
Petroleum
Natural Gas
Biomass
Solar
Conventional Hydro
Pumped Storage
Nuclear
Battery

2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 1.5 GW based on operational/emergency procedures



SERC-Florida Peninsula

SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six companies across North America that are responsible for the work under FERC approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 PAs, and 6 RCs.

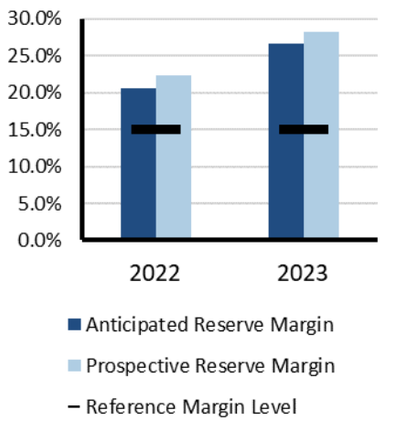
Highlights

- Entities have not identified any emerging reliability issues or operational concerns for the upcoming summer season.
- Entities continue to perform resource studies to ensure resource adequacy to meet the summer peak demand and to maintain system reliability.
- Entities continue to participate actively in the SERC Near-Term and Long-Term Working Groups. These groups identify emerging and potential reliability impacts on transmission and resource adequacy along with transfer capability.
- SERC probabilistic analysis indicates negligible risk for resource shortfall. The 2022 study found negligible LOLH and EUE during summer months for a similar resource mix and demand levels

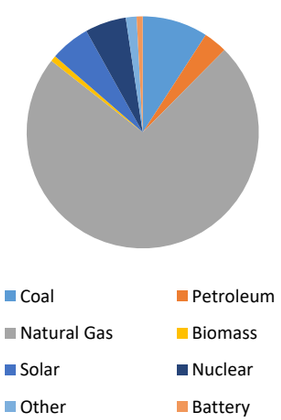
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

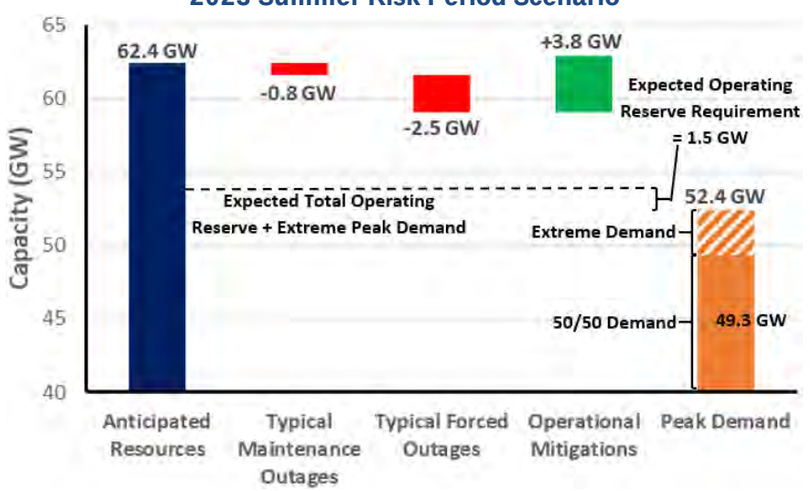
On-Peak Reserve Margin



On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 3.8 GW based on operational/ emergency procedures



SERC-Southeast

SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC is one of the six companies across North America that are responsible for the work under FERC approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the southeastern and central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities, and 6 RCs.

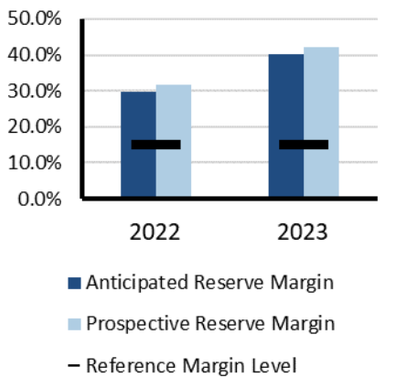
Highlights

- Entities have not identified any emerging reliability issues for the upcoming summer season that will impact resource adequacy.
- The available system capacity for the upcoming summer season meets or exceeds the reserve margin target. Reliability is supported by a diverse fuel mix, firm natural gas contracts, and power purchases.
- Entities continue to participate actively in the SERC near-term and long-term working groups. These groups identify emerging and potential reliability impacts on transmission and resource adequacy along with transfer capability.
- Probabilistic analysis indicates almost no risk for resource shortfall.

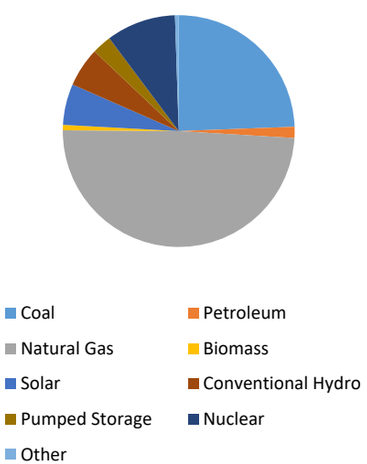
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

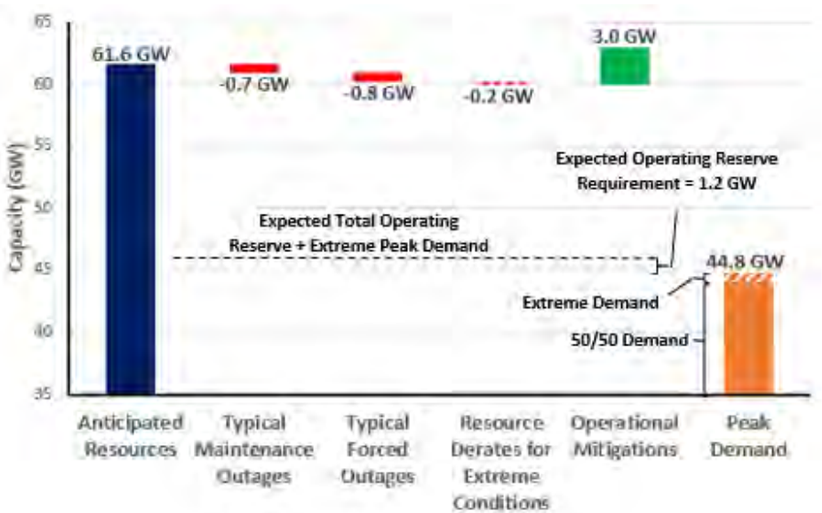
On-Peak Reserve Margin



On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: A total of 3.0 GW based on operational/ emergency procedures



SPP

SPP PC footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP long-term assessment is reported based on the Planning Coordinator footprint, which touches parts of the Midwest Reliability Organization Regional Entity and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million.

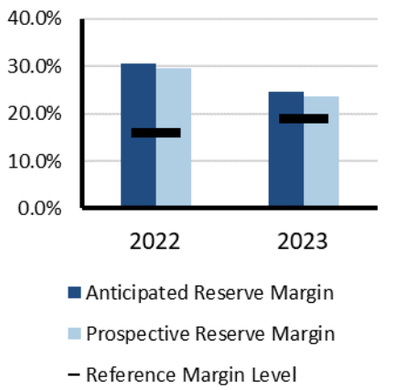
Highlights

- At this time, SPP projects a low likelihood of any emerging reliability issues impacting the area for the 2023 summer season.
- BA generation capacity deficiency risks remain depending on wind generation output levels and unanticipated generation outages in combination with high load periods.
- SPP performed a statistical analysis of risk of energy emergencies for the upcoming summer based on historical data. They found it likely that operators would use part of the 2 GW operating reserves and issue EEA1 and EEA2 level approximately one day each summer; it is likely that operators would deplete all operating reserves approximately once every five summers, resulting in an EEA3.
- Using the current operational processes and procedures, SPP will continue to assess the needs for the 2023 summer season and will adjust as needed to ensure that real-time reliability is maintained throughout the summer time frame.

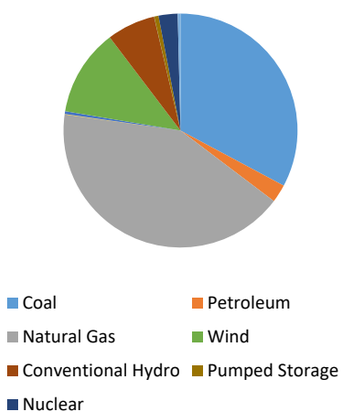
Risk Scenario Summary

Expected resources are sufficient to meet operating reserve requirements under normal peak-demand and outage scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e. demand response and transfers from neighboring systems) and EEAs.

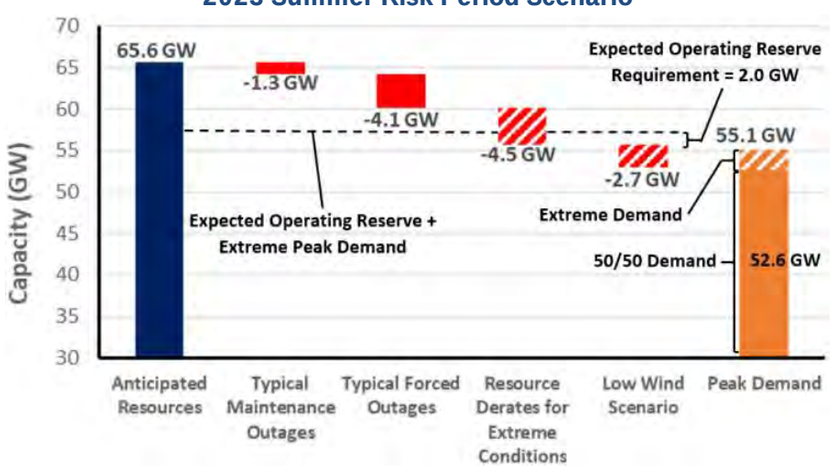
On-Peak Reserve Margin



On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand is a 5% increase from net internal demand

Maintenance & Forced Outages: Represent 5-year historical averages; calculated from SPP's generation assessment process

Extreme Derates: Additional unavailable capacity from operational data at high demand periods

Low Wind Scenario: Derates reflecting a low-wind day in the summer



Texas RE-ERCOT

The Electric Reliability Council of Texas (ERCOT) is the ISO for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT is summer-peaking. It covers approximately 200,000 square miles, connects over 52,700 miles of transmission lines, has over 1,100 generation units, and serves more than 26 million customers. Texas RE is responsible for the RE functions described in the Energy Policy Act of 2005 for ERCOT. On November 3, 2022, the Public Utility Commission of Texas issued an order directing ERCOT to assume the duties and responsibilities of the Reliability Monitor for the Texas power grid.

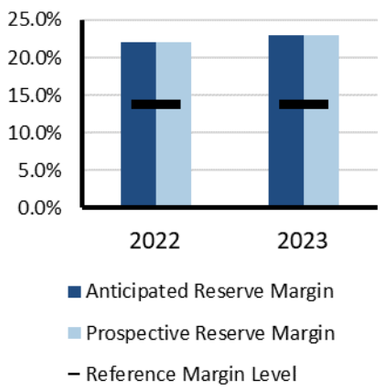
Highlights

- Given an Anticipated Reserve Margin of 23% and Reference Reserve Margin of 13.75%, ERCOT expects to have sufficient operating reserves in expected normal summer system conditions.
- Solar PV nameplate capacity expected for the 2023 summer season is 4.4 GW higher than the forecast amount reported for the 2022 SRA.
- Several generator owners in the ERCOT area indicated they could run out of NOx emission allowances by July 2023 under U.S. EPA's Good Neighbor Plan. Texas filed a motion to stay the EPA's regulatory action. A delay in implementation has alleviated these concerns. ERCOT's probabilistic risk assessment indicates a low probability of energy emergency conditions during the summer peak load period, but the risk increases into the early evening hours due reductions of solar PV generation. There is a 4% probability that ERCOT will declare an EEA1 during the expected daily peak load hour increasing up to 19% probability at the highest risk hour ending at 8:00 p.m.
- System stability and strength stemming from the growth of IBRs remains a concern. ERCOT is also experiencing large increases in renewable production curtailments due to transmission constraints, and these curtailments are increasingly occurring at solar PV sites.

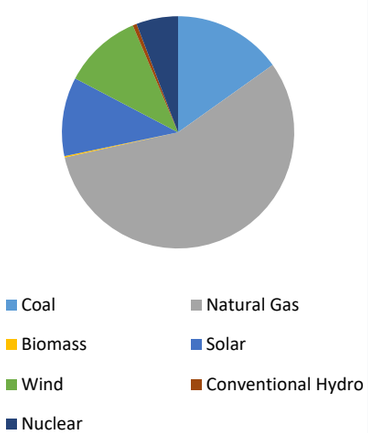
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal and extreme peak-demand scenarios. Extreme generator outages combined with low-wind output during extreme peak demand could result in the need to employ operating mitigations such as demand response, EEAs, and localized load shedding.

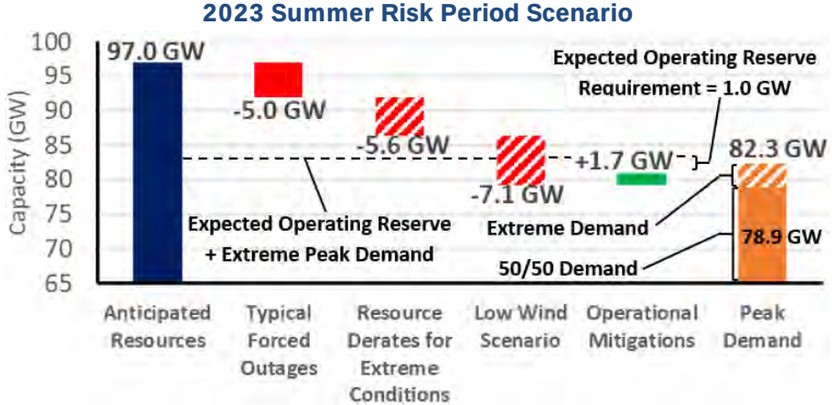
On-Peak Reserve Margin



On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand represents weather conditions 2% worse than summer peak in 2011

Forced Outages: Based on the 95th percentile of historical averages of forced outages for June through September weekdays, hours ending 3:00–8:00 p.m. local time for the last three (2019–2021) summer seasons

Low Wind Scenario: Based on the 10th percentile of historical averages of hourly wind for June through September, hours ending 1:00–9:00 p.m. local time

Extreme Derates: Based on the 95th percentile of historical averages of forced outages for June through September weekdays, hours ending 3:00–8:00 p.m. local time for the last five (2019–2021) summer seasons

Operational Mitigations: Additional capacity from switchable generation and additional imports



WECC-AB

WECC-AB (Alberta) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of Alberta, Canada. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

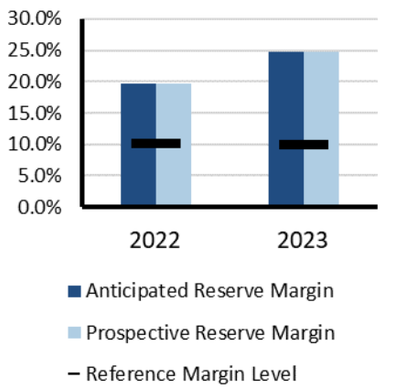
Highlights

- The Western Interconnection is experiencing heightened reliability risks heading into the summer of 2023 due to increased supply-side shortages along with the ongoing drought impacts in some areas, continued wildfire threats, and expanding heat wave events.
- There is 35% less coal-fired generator capacity in Alberta compared to last summer (446 MW). Resource additions include 554 MW of natural-gas-fired generation, 336 MW of new solar PV resources, and 1,350 MW of new wind generation.
- Based on a WECC Probabilistic Assessment, the WECC-AB assessment area had negligible LOLH and EUE.
- Alberta is expected to have sufficient resource availability to meet demand and cover reserves on the peak hour at 4:00 p.m. under a summer peak defined as a one-in-ten probability at the 90th percentile with any combination or accumulation of derates.

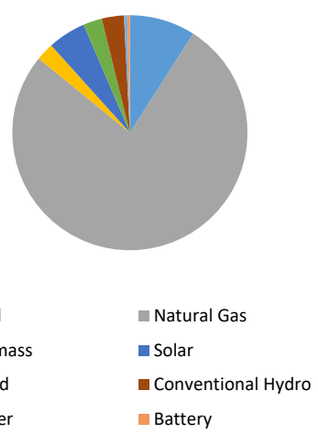
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios

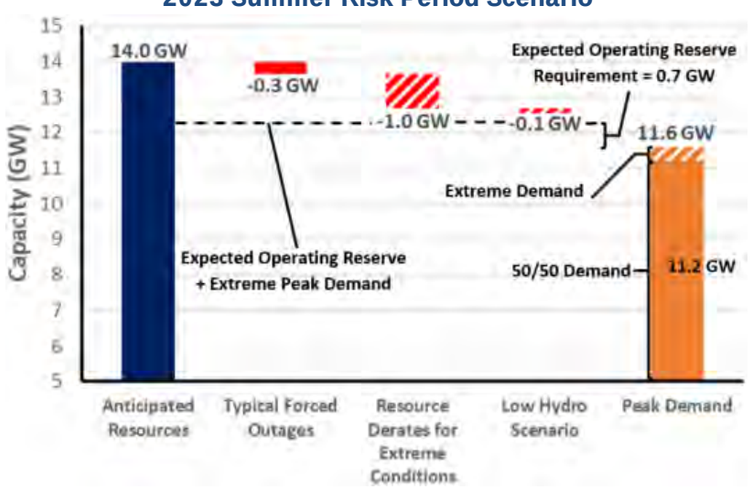
On-Peak Reserve Margin



On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Typical Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) point of resource performance distribution

Low Hydro Scenario: Reduced hydro availability resulting from drought conditions



WECC-BC

WECC-British Columbia (BC) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of British Columbia, Canada. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

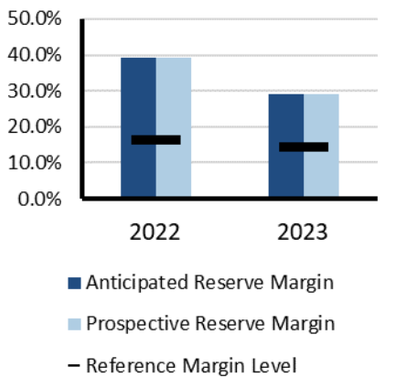
Highlights

- The Western Interconnection is experiencing heightened reliability risks heading into the summer of 2023 due to increased supply-side shortages along with the ongoing drought impacts in some areas, continued wildfire threats, and expanding heat wave events.
- BC shows adequate reserve margins to meet demand under extreme conditions.
- Based on a WECC Probabilistic Assessment, the WECC-BC assessment area had negligible LOLH and EUE.
- BC is expected to have sufficient resource availability to meet demand and cover reserves on the peak hour at 4:00 p.m., under a summer peak defined as a one-in-ten probability at the 90th percentile with any combination or accumulation of derates.

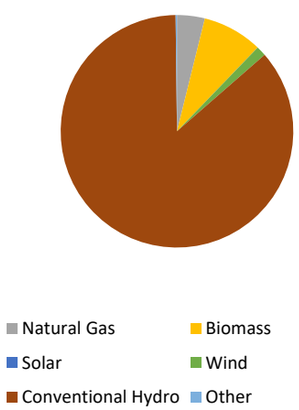
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under the extreme peak demand and outage scenarios studied.

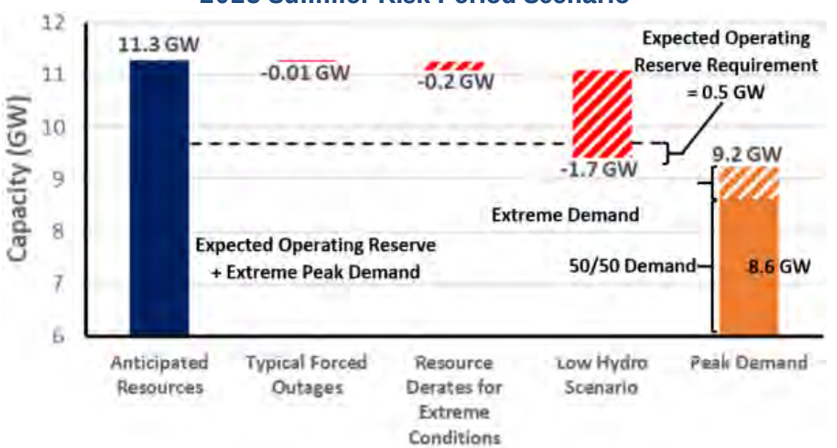
On-Peak Reserve Margin



On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) resource performance distribution at peak hour

Low Hydro Scenario: Reduced hydro availability resulting from drought conditions



WECC-CA/MX

WECC-CA/MX is a summer-peaking assessment area in the WECC Regional Entity that includes parts of California, Nevada, and Baja California, Mexico. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

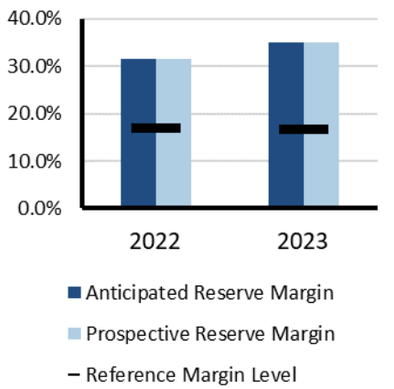
Highlights

- The Western Interconnection is experiencing heightened reliability risks heading into the summer of 2023 due to increased supply-side shortages along with the ongoing drought impacts in some areas, continued wildfire threats, and expanding heat wave events.
- CA/MX shows adequate reserve margins under expected conditions on the peak hour. However, increased risk occurs during the hours after peak demand and into the evening due to the variability of energy availability. CA/MX is typically reliant on imports during these periods.
- Based on a WECC Probabilistic Assessment, WECC-CA/MX is projected to have negligible-to-low amounts of LOLH (<0.5 hours) this summer. Variation in LOLH is attributable to the amount of Tier 1 resources that connect before the later months.
- CA/MX is expected to have sufficient resource availability to meet demand and cover reserves on the peak hour at 4:00 p.m. under a summer peak defined as a one-in-ten probability at the 90th percentile with any combination or accumulation of derates.
- For the peak riskiest hour ending 8:00 pm (four hours later than the peak) under an extreme summer peak load, CA/MX would need to rely on increased imports to maintain adequate reserves. Under expected net internal demand for the same riskiest hour (not an extreme summer peak for that hour), any of the typical outages or extreme derates would also cause a need for increased reliance on imports.

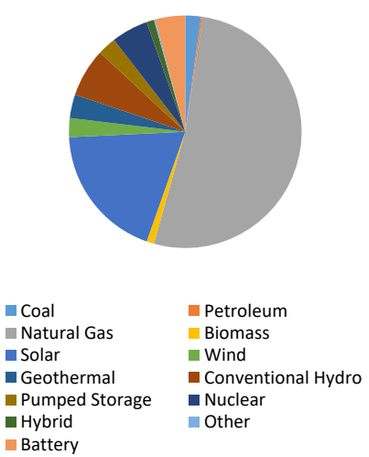
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios studied.

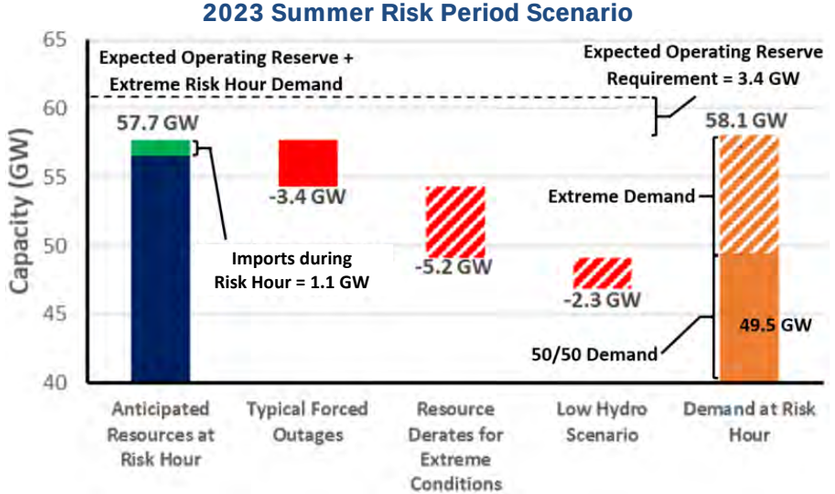
On-Peak Reserve Margin



On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at 8:00 p.m. local time as solar PV output is diminished and demand remains high

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Estimated using market forced outage model

Extreme Derates: On natural gas units based on historic data and manufacturer data for temperature performance and outages

Low Hydro Scenario: Reduced hydro availability resulting from drought conditions



WECC-NW

WECC-NW is a summer-peaking assessment area in the WECC Regional Entity. The area includes Colorado, Idaho, Montana, Oregon, Utah, Washington, Wyoming and parts of California, Nebraska, Nevada, and South Dakota. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

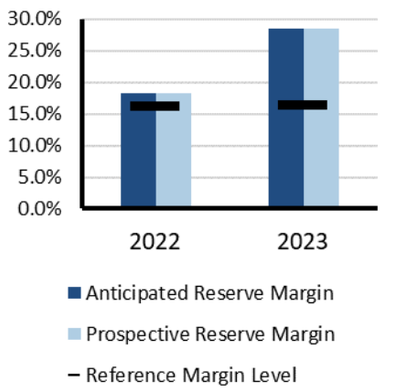
Highlights

- The Western Interconnection is experiencing heightened reliability risks heading into the summer of 2023 due to increased supply-side shortages along with the ongoing drought impacts in some areas, continued wildfire threats, and expanding heat wave events.
- NW shows adequate reserve margins under expected conditions on the peak hour. However, NW shows increased risk a few hours later during the peak riskiest hour, due to the variability of energy availability later in the evenings. NW would be reliant on increased imports.
- Based on a WECC Probabilistic Assessment, the WECC-NW assessment area had negligible LOLH and EUE.
- WECC-NW would need to rely on imports to maintain adequate reserves on the peak riskiest hour (five hours later at 9:00 p.m.) under an extreme summer peak load and either extreme thermal or extreme hydro derates or any combination of two other extreme derate scenarios.

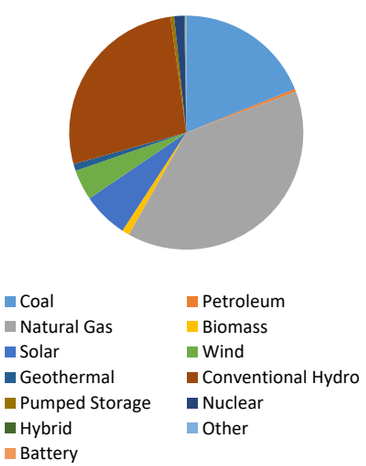
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios.

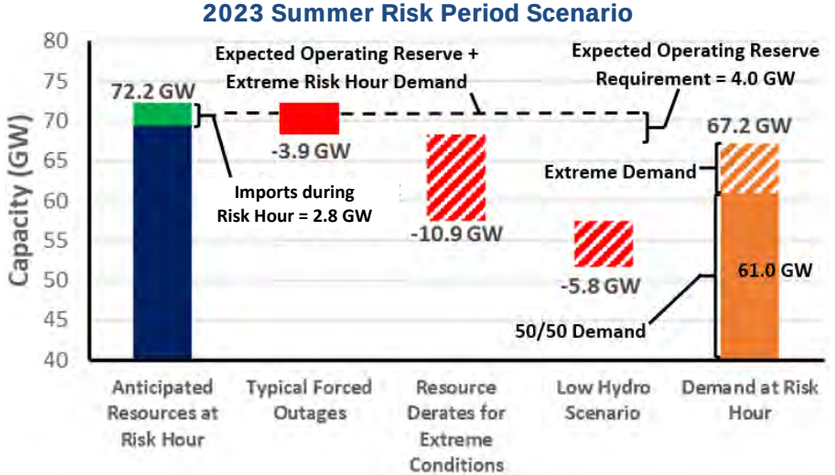
On-Peak Reserve Margin



On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

- **Risk Period:** Highest risk for unserved energy at 9:00 p.m. local time as solar PV output is diminished and demand remains high
- **Demand Scenarios:** Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour
- **Forced Outages:** Average seasonal outages
- **Extreme Derates:** Using (90/10) scenario
- **Low Hydro Scenario**: Reduced hydro availability resulting from drought conditions



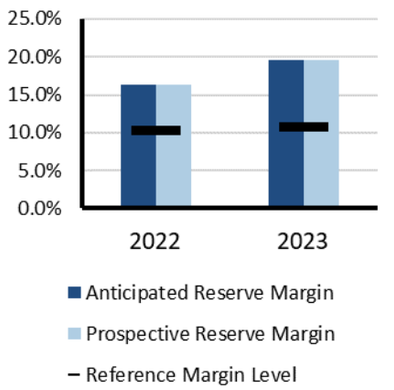
WECC-SW

WECC-SW is a summer-peaking assessment area in the WECC Regional Entity. It includes Arizona, New Mexico, and part of California and Texas. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada as well as the northern portion of Baja California in Mexico and all or portions of the 14 Western United States in between.

Highlights

- The Western Interconnection is experiencing heightened reliability risks heading into the summer of 2023 due to increased supply-side shortages along with the ongoing drought impacts in some areas, continued wildfire threats, and expanding heat wave events.
- WECC-SW shows adequate reserve margins to meet demand under extreme conditions.
- Based on a WECC Probabilistic Assessment, the WECC-SW assessment area had negligible LOLH and EUE.
- WECC-SW is expected to have sufficient resource availability to meet demand and cover reserves on the peak hour at 5:00 p.m. under a summer peak defined as a one-in-ten probability at the 90th percentile with any combination or accumulation of derates.

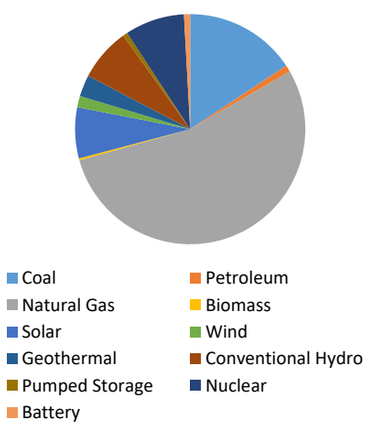
On-Peak Reserve Margin



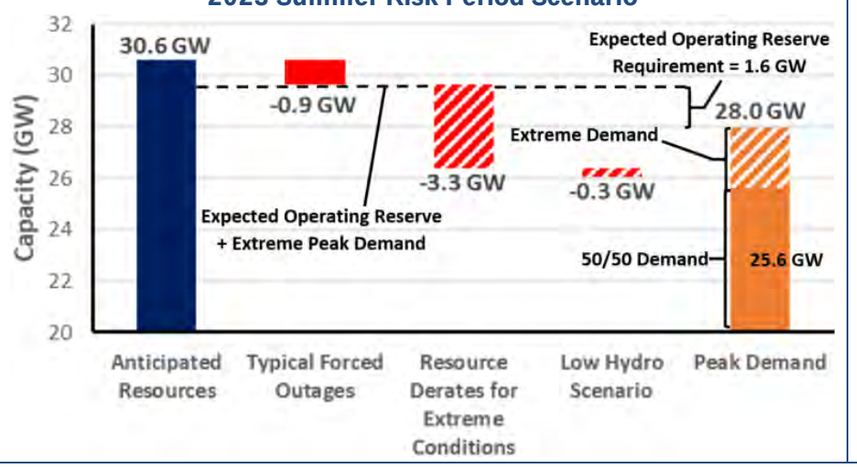
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand (5:00 p.m. local)

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Low Hydro Scenario: Reduced hydro availability resulting from drought conditions

Data Concepts and Assumptions

The table below explains data concepts and important assumptions used throughout this assessment.

General Assumptions

- Reliability of the interconnected BPS is comprised of both adequacy and operating reliability:
  - Adequacy is the ability of the electricity system to supply the aggregate electric power and energy requirements of the electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
  - Operating reliability is the ability of the electricity system to withstand sudden disturbances, such as electric short-circuits or unanticipated loss of system components.
- The reserve margin calculation is an important industry planning metric used to examine future resource adequacy.
- All data in this assessment is based on existing federal, state, and provincial laws and regulations.
- Differences in data collection periods for each assessment area should be considered when comparing demand and capacity data between year-to-year seasonal assessments.
- *2022 Long-Term Reliability Assessment* data has been used for most of this 2023 summer assessment period augmented by updated load and capacity data.
- A positive net transfer capability would indicate a net importing assessment area; a negative value would indicate a net exporter.

Demand Assumptions

- Electricity demand projections, or load forecasts, are provided by each assessment area.
- Load forecasts include peak hourly load[10] or total internal demand for the summer and winter of each year.[11]
- Total internal demand projections are based on normal weather (50/50 distribution[12]) and are provided on a coincident[13] basis for most assessment areas.
- Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour.

Resource Assumptions

Resource planning methods vary throughout the North American BPS. NERC uses the categories below to provide a consistent approach for collecting and presenting resource adequacy. Because the electrical output of variable energy resources (e.g., wind, solar PV) depends on weather conditions, their contribution to reserve margins and other on-peak resource adequacy analysis is less than their nameplate capacity.

Anticipated Resources:

- **Existing-Certain Capacity**: Included in this category are commercially operable generating unit or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the summer season: unit must have a firm capability and have a power purchase agreement with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or where energy-only markets exist, unit must be a designated market resource eligible to bid into the market.
- **Tier 1 Capacity Additions**: This category includes capacity that either is under construction or has received approved planning requirements.
- **Net Firm Capacity Transfers (Imports minus Exports)**: This category includes transfers with firm contracts.

[10] *Glossary of Terms* used in NERC Reliability Standards

[11] The summer season represents June–September and the winter season represents December–February.

[12] Essentially, this means that there is a 50% probability that actual demand will be higher and a 50% probability that actual demand will be lower than the value provided for a given season/year.

[13] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval; this is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year. SERC and FRCC calculate total internal demand on a noncoincidental basis.

Prospective Resources: Includes all anticipated resources plus the following:

Existing-Other Capacity: Included in this category are commercially operable generating units or portions of generating units that could be available to serve load for the period of peak demand for the season but do not meet the requirements of existing-certain.

Reserve Margin Descriptions

Planning Reserve Margin: This is the primary metric used to measure resource adequacy; it is defined as the difference in resources (anticipated or prospective) and net internal demand then divided by net internal demand and shown as a percentage.

Reference Margin Level: The assumptions and naming convention of this metric vary by assessment area. The Reference Margin Level can be determined using both deterministic and probabilistic (based on a 0.1/year loss of load study) approaches. In both cases, this metric is used by system planners to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing a Reference Margin Level is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increase demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, a Reference Margin Level is established by a state, provincial authority, ISO/RTO, or other regulatory body. In some cases, the Reference Margin Level is a requirement. Reference Margin Levels may be different for the summer and winter seasons. If a Reference Margin Level is not provided by an assessment area, NERC applies 15% for predominately thermal systems and 10% for predominately hydro systems.

Seasonal Risk Scenario Chart Description

Each assessment area performed an operational risk analysis that was used to produce the seasonal risk scenario charts in the Regional Assessments Dashboards. The chart presents deterministic scenarios for further analysis of different resource and demand levels: The left blue column shows anticipated resources, and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand and the extreme summer peak demand—both determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources, such as the following:

- Reductions for typical generation outages (i.e., maintenance and forced outages that are not already accounted for in anticipated resources)
- Reductions that represent additional outage or performance derating by resource type for extreme, low-probability conditions (e.g., drought condition impacts on hydroelectric generation, low-wind scenario affecting wind generation, fuel supply limitations, or extreme temperature conditions that result in reduced thermal generation output)
- Additional capacity resources that represent quantified capacity from operational procedures, if any, that are made available during scarcity conditions

Not all assessment areas have the same categories of adjustments to anticipated resources. Furthermore, each assessment area determined the adjustments to capacity based on methods or assumptions that are summarized below the chart. Methods and assumptions differ by assessment area and may not be comparable.

The chart enables evaluation of resource levels against levels of expected operating reserve requirement and the forecasted demand. Furthermore, the effects from extreme events can also be examined by comparing resource levels after applying extreme-scenario derates and/or extreme summer peak demand.

Resource Adequacy

The Anticipated Reserve Margin, which is based on available resource capacity, is a metric used to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecast peak demand.[14] Large year-to-year changes in anticipated resources or forecast peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. All assessment areas have sufficient Anticipated Reserve Margins to meet or exceed their Reference Margin Level for the 2023 summer as shown in **Figure 4**.

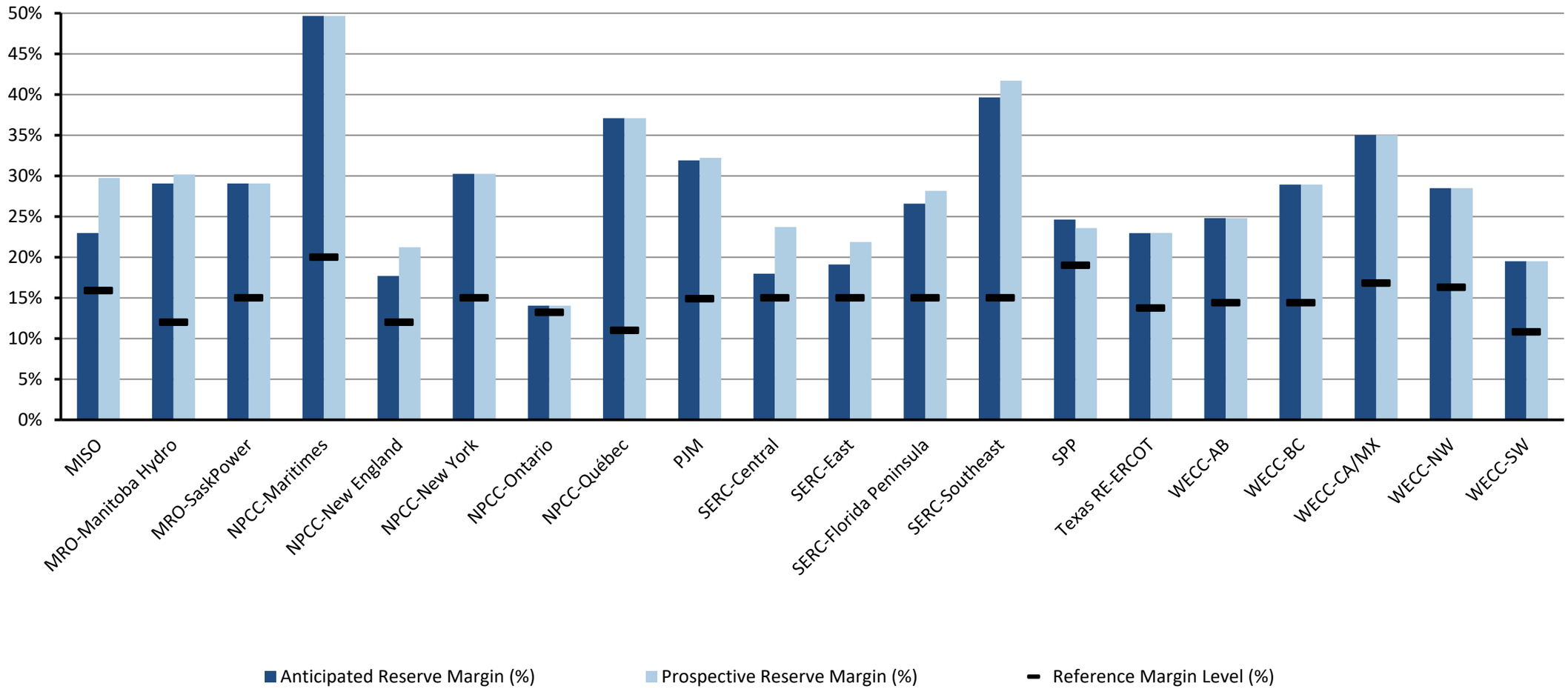
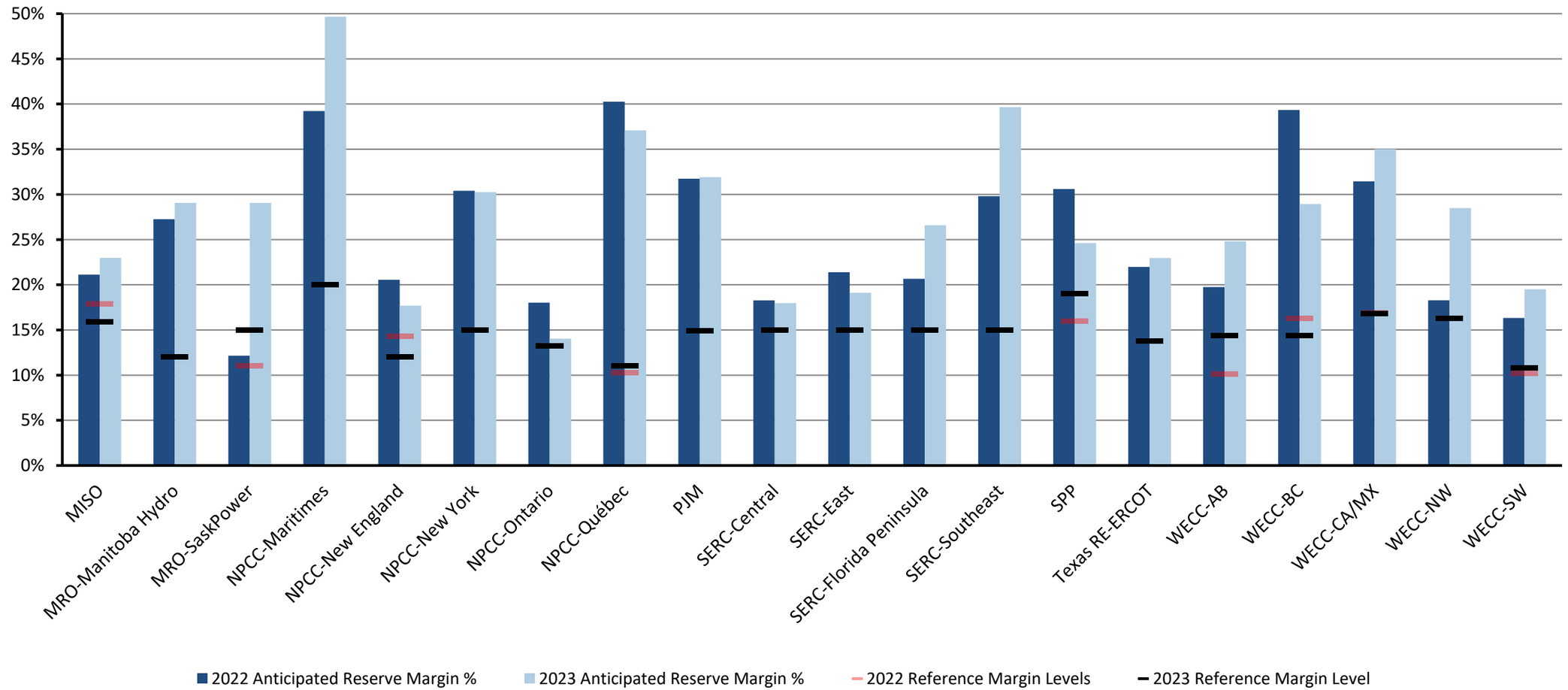


Figure 4: Summer 2023 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[14] Generally, anticipated resources include generators and firm capacity transfers that are expected to be available to serve load during electrical peak loads for the season. Prospective resources are those that could be available but do not meet criteria to be counted as anticipated resources. Refer to the **Data Concepts and Assumptions** section for additional information on Anticipated/Prospective Reserve Margins, anticipated/prospective resources, and Reference Margin Levels.

Changes from Year-to-Year

Figure 5 provides the relative change in the forecast Anticipated Reserve Margins from the 2022 summer to the 2023 summer. A significant decline can indicate potential operational issues that emerge between reporting years. NPCC-Ontario, SPP and WECC-BC have noticeable reductions in anticipated resources with NPCC-Ontario close to falling below its Reference Margin Level for the 2023 summer. NPCC-Ontario is experiencing ongoing nuclear refurbishments and recent retirements will make it difficult to accommodate unplanned generator or transmission outages. NPCC-Ontario will rely on demand response and transfers from neighbors during a higher load scenario to avoid load interruption. The lower Anticipated Reserve Margins for NPCC-Maritimes, NPCC-Québec, SERC-C, and WECC-AB do not present reliability concerns on peak for this upcoming summer. Additional details for each assessment area are provided in the **Data Concepts and Assumptions** and **Regional Assessments Dashboards** sections.



Note: The areas that only have one bar have the same Reference Margin Level for both years.

Figure 5: Summer 2022 and Summer 2023 Anticipated Reserve Margins Year-to-Year Change

Net Internal Demand

The changes in forecasted Net Internal Demand for each assessment area are shown in Figure 6.[15] Assessment areas develop these forecasts based on historic load and weather information as well as other long-term projections.

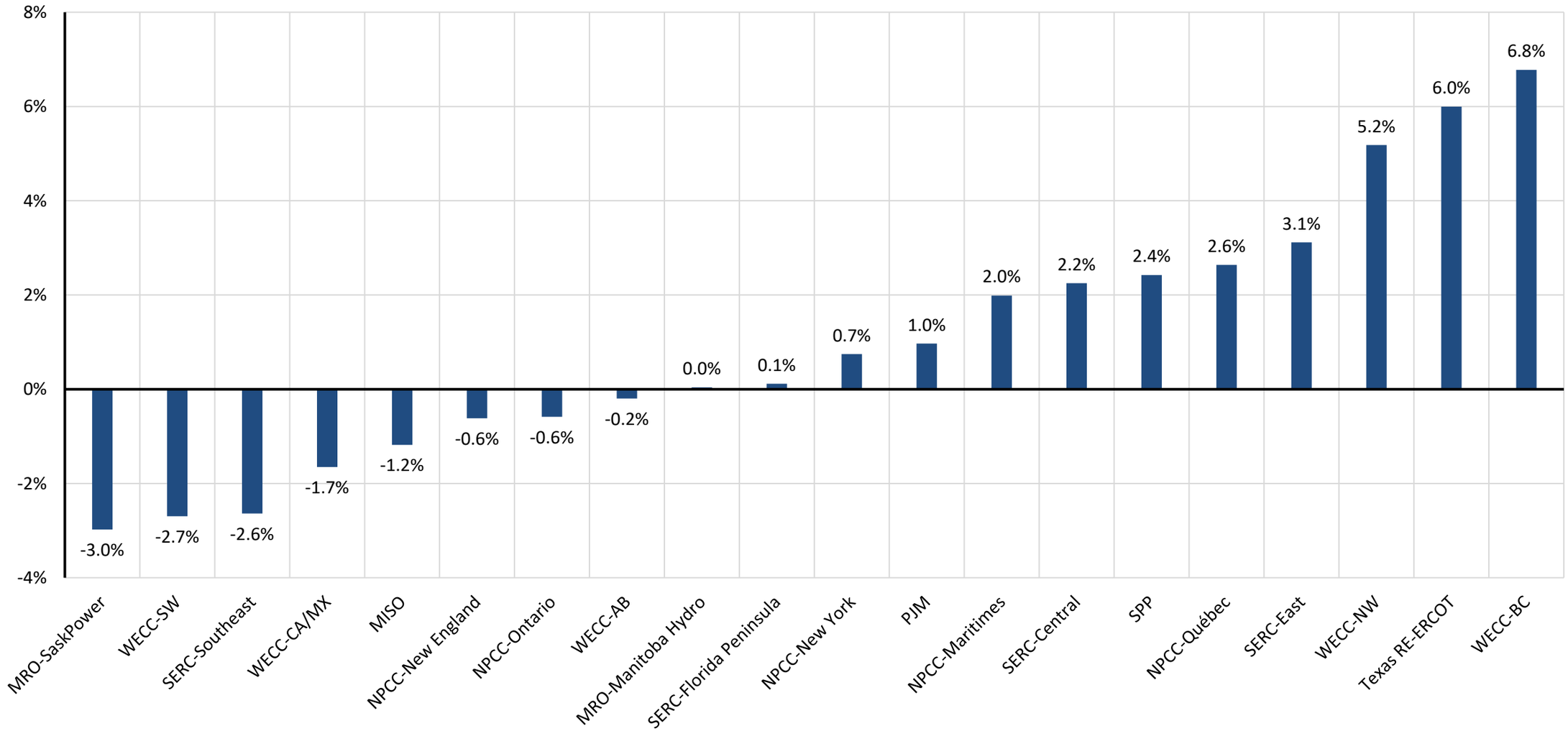


Figure 6: Change in Net Internal Demand—Summer 2022 Forecast Compared to Summer 2023 Forecast

[15] Changes in modeling and methods may also contribute to year-to-year changes in forecasted net internal demand projections.

Demand and Resource Tables

Peak demand and supply capacity data—resource adequacy data—for each assessment area are as follows in each table (in alphabetical order).

MISO			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	124,506	123,728	-0.6%
Demand Response: Available	6,287	6,903	9.8%
Net Internal Demand	118,220	116,825	-1.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	141,844	140,650	-0.8%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,353	3,018	123.1%
Anticipated Resources	143,197	143,668	0.3%
Existing-Other Capacity	669	668	-0.1%
Prospective Resources	149,756	151,579	1.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	21.1%	23.0%	1.8
Prospective Reserve Margin	26.7%	29.7%	3.1
Reference Margin Level	17.9%	15.9%	-2.0

MRO-Manitoba Hydro			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,059	3,060	0.0%
Demand Response: Available	0	0	-
Net Internal Demand	3,059	3,060	0.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,523	5,731	3.8%
Tier 1 Planned Capacity	186	91	-50.9%
Net Firm Capacity Transfers	-1,816	-1,872	3.1%
Anticipated Resources	3,893	3,950	1.5%
Existing-Other Capacity	44	34	-23.4%
Prospective Resources	3,937	3,984	1.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.3%	29.1%	1.8
Prospective Reserve Margin	28.7%	30.2%	1.5
Reference Margin Level	12.0%	12.0%	0.0

MRO-SaskPower			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,656	3,539	-3.2%
Demand Response: Available	60	50	-16.7%
Net Internal Demand	3,596	3,489	-3.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	3,743	4,213	12.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	290	290	0.0%
Anticipated Resources	4,033	4,503	11.7%
Existing-Other Capacity	0	0	-
Prospective Resources	4,033	4,503	11.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	12.2%	29.1%	16.9
Prospective Reserve Margin	12.2%	29.1%	16.9
Reference Margin Level	11.0%	15.0%	4.0

NPCC-Maritimes			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,475	3,612	3.9%
Demand Response: Available	255	328	28.6%
Net Internal Demand	3,220	3,284	2.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,419	4,834	9.4%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	64	81	26.6%
Anticipated Resources	4,483	4,915	9.6%
Existing-Other Capacity	0	0	-
Prospective Resources	4,483	4,915	9.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	39.2%	49.7%	10.4
Prospective Reserve Margin	39.2%	49.7%	10.4
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New England			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	25,300	25,111	-0.7%
Demand Response: Available	483	447	-7.5%
Net Internal Demand	24,817	24,664	-0.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	28,626	27,997	-2.2%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,292	1,030	-20.3%
Anticipated Resources	29,918	29,027	-3.0%
Existing-Other Capacity	911	872	-4.3%
Prospective Resources	30,829	29,899	-3.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.6%	17.7%	-2.9
Prospective Reserve Margin	24.2%	21.2%	-3.0
Reference Margin Level	14.3%	12.0%	-2.3

NPCC-Ontario			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	22,546	22,439	-0.5%
Demand Response: Available	666	687	3.1%
Net Internal Demand	21,880	21,752	-0.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	25,648	24,575	-4.2%
Tier 1 Planned Capacity	24	9	-61.5%
Net Firm Capacity Transfers	150	223	48.5%
Anticipated Resources	25,822	24,807	-3.9%
Existing-Other Capacity	0	0	-
Prospective Resources	25,822	24,807	-3.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	18.0%	14.0%	-4.0
Prospective Reserve Margin	18.0%	14.0%	-4.0
Reference Margin Level	13.3%	13.2%	0.0

NPCC-New York			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	31,765	32,049	0.9%
Demand Response: Available	1,170	1,226	4.8%
Net Internal Demand	30,595	30,823	0.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	37,431	37,216	-0.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	2,465	2,932	18.9%
Anticipated Resources	39,896	40,148	0.6%
Existing-Other Capacity	0	0	-
Prospective Resources	39,896	40,148	0.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.4%	30.3%	-0.1
Prospective Reserve Margin	30.4%	30.3%	-0.1
Reference Margin Level	15.0%	15.0%	0.0

NPCC-Québec			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	22,271	22,859	2.6%
Demand Response: Available	0	0	-
Net Internal Demand	22,271	22,859	2.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	33,542	33,690	0.4%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-2,304	-2,353	2.1%
Anticipated Resources	31,238	31,337	0.3%
Existing-Other Capacity	0	0	-
Prospective Resources	31,238	31,337	0.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	40.3%	37.1%	-3.2
Prospective Reserve Margin	40.3%	37.1%	-3.2
Reference Margin Level	10.3%	11.0%	0.7

PJM			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	148,938	149,059	0.1%
Demand Response: Available	8,527	7,288	-14.5%
Net Internal Demand	140,411	141,771	1.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	184,837	186,540	0.9%
Tier 1 Planned Capacity	10	0	-100.0%
Net Firm Capacity Transfers	124	463	273.4%
Anticipated Resources	184,971	187,003	1.1%
Existing-Other Capacity	0	0	-
Prospective Resources	185,095	187,466	1.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	31.7%	31.9%	0.2
Prospective Reserve Margin	31.8%	32.2%	0.4
Reference Margin Level	14.9%	14.9%	0.0

SERC-East			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	42,883	43,889	2.3%
Demand Response: Available	1,298	1,008	-22.3%
Net Internal Demand	41,585	42,881	3.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	49,380	50,452	2.2%
Tier 1 Planned Capacity	486	0	-100.0%
Net Firm Capacity Transfers	612	624	2.0%
Anticipated Resources	50,478	51,076	1.2%
Existing-Other Capacity	1,097	1,182	7.8%
Prospective Resources	51,575	52,258	1.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	21.4%	19.1%	-2.3
Prospective Reserve Margin	24.0%	21.9%	-2.2
Reference Margin Level	15.0%	15.0%	0.0

SERC-Central			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	41,267	42,223	2.3%
Demand Response: Available	1,841	1,910	3.7%
Net Internal Demand	39,426	40,313	2.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	47,424	46,964	-1.0%
Tier 1 Planned Capacity	0	93	-
Net Firm Capacity Transfers	-795	1,068	-
Anticipated Resources	46,629	47,556	2.0%
Existing-Other Capacity	4,808	2,313	-51.9%
Prospective Resources	51,437	49,868	-3.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	18.3%	18.0%	-0.3
Prospective Reserve Margin	30.5%	23.7%	-6.8
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	52,172	52,195	0.0%
Demand Response: Available	2,932	2,898	-1.2%
Net Internal Demand	49,240	49,297	0.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	56,571	60,074	6.2%
Tier 1 Planned Capacity	2,540	1,742	-31.4%
Net Firm Capacity Transfers	300	589	96.3%
Anticipated Resources	59,411	62,405	5.0%
Existing-Other Capacity	847	776	-8.4%
Prospective Resources	60,258	63,181	4.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.7%	26.6%	5.9
Prospective Reserve Margin	22.4%	28.2%	5.8
Reference Margin Level	15.0%	15.0%	0.0

SERC-Southeast			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	47,258	46,127	-2.4%
Demand Response: Available	1,946	2,010	3.3%
Net Internal Demand	45,312	44,117	-2.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	59,828	59,559	-0.4%
Tier 1 Planned Capacity	1,514	2,865	89.3%
Net Firm Capacity Transfers	-2,524	-815	-67.7%
Anticipated Resources	58,818	61,609	4.7%
Existing-Other Capacity	859	908	5.7%
Prospective Resources	59,677	62,517	4.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	29.8%	39.6%	9.8
Prospective Reserve Margin	31.7%	41.7%	10.0
Reference Margin Level	15.0%	15.0%	0.0

SPP			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	52,040	53,468	2.7%
Demand Response: Available	658	842	27.9%
Net Internal Demand	51,382	52,626	2.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	67,245	65,821	-2.1%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-144	-238	65.0%
Anticipated Resources	67,101	65,583	-2.3%
Existing-Other Capacity	0	0	-
Prospective Resources	66,554	65,036	-2.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.6%	24.6%	-6.0
Prospective Reserve Margin	29.5%	23.6%	-5.9
Reference Margin Level	16.0%	19.0%	3.0

Texas RE-ERCOT			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	77,317	82,307	6.5%
Demand Response: Available	2,856	3,380	18.3%
Net Internal Demand	74,461	78,927	6.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	89,603	94,580	5.6%
Tier 1 Planned Capacity	1,199	2,445	103.9%
Net Firm Capacity Transfers	20	20	0.0%
Anticipated Resources	90,822	97,045	6.9%
Existing-Other Capacity	0	0	-
Prospective Resources	90,850	97,073	6.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.0%	23.0%	1.0
Prospective Reserve Margin	22.0%	23.0%	1.0
Reference Margin Level	13.75%	13.75%	0.0

WECC-AB			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,228	11,206	-0.2%
Demand Response: Available	0	0	-
Net Internal Demand	11,228	11,206	-0.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	11,926	13,759	15.4%
Tier 1 Planned Capacity	1,082	227	-79.0%
Net Firm Capacity Transfers	437	0	-100.0%
Anticipated Resources	13,445	13,986	4.0%
Existing-Other Capacity	0	0	-
Prospective Resources	13,445	13,986	4.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	19.7%	24.8%	5.1
Prospective Reserve Margin	19.7%	24.8%	5.1
Reference Margin Level	10.1%	9.9%	-0.2

WECC-BC			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	8,088	8,636	6.8%
Demand Response: Available	0	0	-
Net Internal Demand	8,088	8,636	6.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	11,266	11,135	-1.2%
Tier 1 Planned Capacity	3	0	-100.0%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	11,269	11,135	-1.2%
Existing-Other Capacity	0	0	-
Prospective Resources	11,269	11,135	-1.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	39.3%	28.9%	-10.4
Prospective Reserve Margin	39.3%	28.9%	-10.4
Reference Margin Level	16.3%	14.4%	-1.9

WECC-CA / MX			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	57,269	56,356	-1.6%
Demand Response: Available	844	862	2.2%
Net Internal Demand	56,425	55,494	-1.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	70,791	69,408	-2.0%
Tier 1 Planned Capacity	3,381	5,522	63.3%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	74,172	74,930	1.0%
Existing-Other Capacity	0	0	-
Prospective Resources	74,172	74,930	1.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	31.5%	35.0%	3.6
Prospective Reserve Margin	31.5%	35.0%	3.6
Reference Margin Level	16.9%	16.8%	-0.1

WECC-SW			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	26,720	25,992	-2.7%
Demand Response: Available	399	380	-4.7%
Net Internal Demand	26,321	25,612	-2.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	28,249	26,206	-7.2%
Tier 1 Planned Capacity	1,369	1,655	20.9%
Net Firm Capacity Transfers	1,002	2,747	174.2%
Anticipated Resources	30,620	30,608	0.0%
Existing-Other Capacity	0	0	-
Prospective Resources	30,620	30,608	0.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	16.3%	19.5%	3.2
Prospective Reserve Margin	16.3%	19.5%	3.2
Reference Margin Level	10.2%	10.8%	0.6

WECC-NW			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	63,214	66,366	5.0%
Demand Response: Available	1,104	1,038	-6.0%
Net Internal Demand	62,110	65,328	5.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	70,154	76,587	9.2%
Tier 1 Planned Capacity	798	2,350	194.5%
Net Firm Capacity Transfers	2,517	5,004	98.8%
Anticipated Resources	73,469	83,941	14.3%
Existing-Other Capacity	0	0	-
Prospective Resources	73,469	83,941	14.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	18.3%	28.5%	10.2
Prospective Reserve Margin	18.3%	28.5%	10.2
Reference Margin Level	16.1%	16.3%	0.2

Variable Energy Resource Contributions

Because the electrical output of variable energy resources (e.g., wind, solar PV) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity. The following table shows the capacity contribution of existing wind and solar PV resources at the peak demand hour for each assessment area. Resource contributions are also aggregated by Interconnection and across the entire BPS. For NERC's analysis of risk periods after peak demand (i.e., U.S. assessment areas in WECC), lower contributions of solar PV resources are used because output is diminished during evening periods.

BPS Variable Energy Resources by Assessment Area									
	Wind			Solar			Hydro		
Assessment Area / Interconnection	Nameplate Wind	Expected Wind	Expected Share of Nameplate (%)	Nameplate Solar PV	Expected Solar PV	Expected Share of Nameplate (%)	Nameplate Hydro	Expected Hydro	Expected Share of Nameplate (%)
MISO	30,373	5,488	18%	7,499	3,750	50%	4,884	4,688	96%
MRO-Manitoba Hydro	259	47	18%	-	-	0%	6,220	5,548	89%
MRO-SaskPower	615	203	33%	30	-	0%	851	797	94%
NPCC-Maritimes	1,212	255	21%	4	-	0%	1,315	1,183	90%
NPCC-New England	1,448	186	13%	2,914	1,163	40%	3,565	2,472	69%
NPCC-New York	2,879	331	12%	179	84	47%	6,731	5,067	75%
NPCC-Ontario	4,943	771	16%	478	126	26%	8,985	5,185	58%
NPCC-Québec	3,880	-	0%	10	-	0%	40,307	32,974	82%
PJM	10,923	1,688	15%	5,169	2,984	58%	3,027	3,027	100%
SERC-Central	1,206	564	47%	885	511	58%	4,967	3,315	67%
SERC-East	-	-	0%	1,475	1,473	99%	3,064	3,013	98%
SERC-Florida Peninsula	-	-	0%	7,724	4,534	59%	-	-	0%
SERC-Southeast	-	-	0%	5,305	4,647	88%	3,242	3,288	101%
SPP	32,028	4,500	14%	440	378	86%	5,465	4,996	91%
Texas RE-ERCOT	30,938	10,293	33%	15,958	12,509	78%	563	477	85%
WECC-AB	3,619	309	9%	1,165	763	65%	894	416	47%
WECC-BC	747	137	18%	2	1	50%	16,519	10,124	61%
WECC-CA/MX	9,362	1,111	12%	21,975	14,489	66%	13,957	4,606	33%
WECC-SW	2,994	593	20%	3,493	1,411	40%	1,202	844	70%
WECC-NW	20,296	3,968	20%	9,270	5,062	55%	41,860	22,752	54%
EASTERN INTERCONNECTION	85,886	14,032	16%	32,102	19,649	61%	52,316	42,578	81%
QUÉBEC INTERCONNECTION	3,880	-	0%	10	-	0%	40,307	32,974	82%
TEXAS INTERCONNECTION	30,938	10,293	33%	15,958	12,509	78%	563	477	85%
WECC INTERCONNECTION	37,018	6,118	17%	35,905	21,726	61%	74,432	38,742	52%
INTERCONNECTION TOTAL:	**157,722**	**30,443**	**19%**	**83,975**	**53,885**	**64%**	**167,618**	**114,771**	**68%**

Probabilistic Assessment

Regional Entities and assessment areas provided a resource adequacy risk assessment that was probability-based for the summer season. Results are included in the Highlights section of each assessment area's dashboard and summarized in the table below. The risk assessments account for the hour(s) of greatest risk of resource shortfall. For most areas, the hour(s) of risk coincide with the time of forecasted peak demand; however, some areas incur the greatest risk at other times based on the varying demand and resource profiles. Various risk metrics are provided and include LOLE, LOLH, EUE, and the probabilities of EEA occurrence.

Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight From Assessment**
MISO	Annual probabilistic LOLE study	MISO's RML decreased from 17.9% in 2022 to 15.9% for Summer 2023. The change results from implementing seasonal forced outages and probabilistic distributions of non-firm imports. Operating mitigations are needed in extreme peak summer conditions.
MRO-Manitoba	Verification of NERC 2022 Probabilistic Assessment (2022 ProbA)	The 2022 ProbA results indicate 29 MWh per year of EUE for 2024. Given comparable supply and demand balance, the 2024 EUE is a reasonable estimate for all of 2023. EUE for summer is less than the annual EUE.
MRO-SaskPower	Probability-based capacity adequacy assessment	Results indicate that the expected number of hours with operating reserve deficiency for the 2023 summer season (June to September) is 0.21 hours. September is the month with highest risk.
NPCC	NPCC conducted an all-hour Probabilistic Assessment that consisted of a base case and several more severe scenarios examining low resources, reduced imports, and higher loads. The highest peak load scenario has a 7% probability of occurring.	The assessment forecasts that the NPCC Regional Entity will have an adequate supply of electricity this summer. Necessary strategies and procedures are in place to deal with operational challenges and emergencies as they may develop. Results of the probabilistic analysis by assessment area are below.
NPCC-Maritimes		NPCC's assessment results indicate that Maritimes is likely to use a combination of imports and operating procedures to mitigate resource shortages this summer. Cumulative LOLE (<0.03 days/summer), LOLH (<0.11 hours/summer), or EUE (<5 MWh/summer) were estimated over the May–September summer for all modeled scenarios.
NPCC-New England		NPCC's assessment results indicate that ISO-NE may rely on limited use of its operating procedures to mitigate resource and energy shortages during the summer. The reduced resource case with the highest peak load scenario resulted in a small estimated cumulative LOLE risk (0.12 days/period) with associated LOLHs (0.4 hours/period) and EUE (175 MWh/period) with the highest risk occurring in June. This scenario is based exclusively on the two highest load levels with a 7% chance of occurring and a low resource case consisting of extended summer maintenance across NPCC and reduced imports from PJM.
NPCC-New York		NPCC's assessment results indicate that NYISO may rely on limited use of its operating procedures to mitigate resource and energy shortages during the summer. The reduced resource case with the highest peak load scenario resulted in a small estimated cumulative LOLE risk (0.5 days/summer) with associated LOLH (1.1 hours/summer) and EUE (525 MWh/summer). The highest risk is in June and August.
NPCC-Ontario		NPCC's assessment results indicate that Ontario is likely to use a combination of imports and operating procedures to mitigate resource shortages this summer. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios, including the severe low-likelihood cases. These results indicate that Ontario will be able to obtain necessary supplies from neighbors over a range of conditions.

Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight From Assessment**
NPCC-Québec		Québec is expected to need only limited use of its operating procedures designed to mitigate resource and energy shortages during the summer. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios, including the severe low-likelihood cases.
PJM	Based on 2022 PJM Reserve Requirement Study (RRS)	PJM is expecting a low risk of resources falling below required operating reserves. PJM forecasts a 29% installed reserve margin, well above the target of 14.9%. Due to the low penetration of variable energy resources in PJM relative to PJM's peak load, the hour with most loss of load risk remains the hour with highest forecasted demand.
SERC	Verification of NERC 2022 ProbA Results	The 2022 Base Case results indicated adequate resources for the SERC Region as a whole with an observed LOLE of 0.03 days/year for the year 2024. Trends from 2022 to 2023 indicate little change in study results, so SERC does not anticipate resource adequacy risk for the upcoming summer season.
SERC-Central		Probabilistic analysis indicates no risk for resource shortfall.
SERC-East		Probabilistic analysis shows low risk for July and August with EUE of 2.38 MWh and LOLH 0.005 hours.
SERC-Florida Peninsula		SERC Probabilistic analysis indicates no risk of resource shortfall.
SERC-Southeast		Probabilistic analysis indicates almost no risk of resource shortfall.
SPP	Statistical analysis of the Summer 2022 real time data; Operational process and procedures	Potential risk of using operating reserves and EEA1 or EEA2 is 1 day per summer. Risk of EEA3 is 0.2 days per summer. Risks is associated with low wind generation output levels or unanticipated generation outages in combination with high load periods.
Texas RE-ERCOT	ERCOT's Summer 2023 Probabilistic Assessment	There is a 4% probability that ERCOT will declare an EEA1 during the expected daily peak load hour; Increasing up to 19% probability at the highest risk hour and ending at 8:00 p.m.
WECC	The 2022 Western Assessment of Resource Adequacy provides the most recent probability-based resource adequacy risk assessment for Summer 2023 across WECC's areas.	The Western Interconnection is experiencing heightened reliability risks heading into Summer 2023 due to increased supply-side shortages and fuel constraints along with the ongoing drought impacts in some areas, continued wildfire threats, and expanding heat wave events. The installation of new resources for the summer and the availability of the imports, especially during wide-area heat events, affects resource adequacy for the U.S. assessment areas. The reliability and resource adequacy of the Western Interconnection depends on the ability to move power throughout the footprint.
WECC-AB		Alberta is expected to have sufficient resource availability to meet demand and cover reserves on the peak hour at 4:00 p.m. under a summer peak defined at the 90th percentile with any combination or accumulation of derates.
WECC-BC		BC is expected to have sufficient resource availability to meet demand and cover reserves on the peak hour at 4:00 p.m. under a summer peak defined at the 90th percentile with any combination or accumulation of derates.
WECC-CA/MX		WECC-CA/MX is projected to have negligible-to-low amounts of LOLH (<0.5 hours) this summer with variation attributable to the amount of Tier 1 resources that connect before the later months. Resources are sufficient to meet demand and cover reserves on the peak hour at 3:00

Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight From Assessment**
		p.m. under a summer peak defined at the 90th percentile with any combination or accumulation of derates. However, there is increased risk of insufficient reserves at later hours (up to 8:00 p.m.) due to the variability of energy resource output. Imports to the area are required to cover these risk periods; however, regional resource availability and transmission constraints can affect external assistance during wide area heat events.
WECC-NW		WECC-NW assessment area is projected to have negligible LOLH and EUE this summer with planned resource additions and normal transfer availability. However, some LOLH (<0.1) and EUE (<400 MWh) is anticipated during above-normal demand periods if new resource are delayed or external transfers are disrupted. WECC-NW would rely on imports to maintain adequate reserves on the during the risk hours from 4:00–9:00 p.m. under extreme summer peak load and low-resource conditions (e.g., extreme thermal or extreme hydro derates or combinations of other low energy output scenarios.)
WECC-SW		WECC-SW assessment area is projected to have negligible LOLH and EUE this summer with planned resource additions and normal transfer availability. However, some LOLH (<0.1) and EUE (<150 MWh) is anticipated during above-normal demand periods if new resource are delayed or external transfers are disrupted.

Errata

May 2023

- The Risk Scenario Summaries for SERC-Central and SERC-East were corrected (page 23 and page 24)

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2024 Summer Reliability Assessment

May 2024



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Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of NERC and the six Regional Entities, is a highly reliable, resilient, and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

About this Assessment

NERC's *2024 Summer Reliability Assessment* (*SRA*) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming summer season. In addition, the *SRA* presents peak electricity demand and supply changes and highlights any unique regional challenges or expected conditions that might affect the reliability of the BPS. The reliability assessment process is a coordinated reliability evaluation between the NERC Reliability Assessment Subcommittee, the Regional Entities, and NERC staff with demand and resource projections obtained from the assessment areas. This report reflects an independent assessment by NERC and the ERO Enterprise and is intended to inform industry leaders, planners, operators, and regulatory bodies so that they are better prepared to take necessary actions to ensure BPS reliability. This report also provides an opportunity for industry to discuss plans and preparations to ensure reliability for the upcoming summer period.

Key Findings

NERC's annual *SRA* covers the upcoming four-month (June–September) summer period. This assessment evaluates generation resource and transmission system adequacy as well as energy sufficiency to meet projected summer peak demands and operating reserves. This includes a deterministic evaluation of data submitted for peak demand hour and peak risk hour as well as results from recently updated probabilistic analyses. Additionally, this assessment identifies potential reliability issues of interest and regional topics of concern. While the scope of this seasonal assessment is focused on the upcoming summer, the key findings are consistent with risks and issues that NERC highlighted in the *2023 Long-Term Reliability Assessment (LTRA*), covering a 10-year horizon, and other earlier reliability assessments and reports.[1]

The following findings are derived from NERC and the ERO Enterprise's independent evaluation of electricity generation and transmission capacity as well as potential operational concerns that may need to be addressed for the 2024 summer.

Resource Adequacy Assessment and Energy Risk Analysis

All areas are assessed as having adequate anticipated resources for normal summer peak load conditions (see **Figure 1**). However, the following areas face risks of electricity supply shortfalls during periods of more extreme summer conditions. This determination of elevated risk is based on analysis of plausible scenarios, including 90/10 demand forecasts and historical high outage rates as well as low wind or solar photovoltaic (PV) energy conditions:

- **Midcontinent Independent System Operator (MISO):** New solar and natural-gas-fired generation and additional demand response (DR) resources are offset by generator retirements, lower firm imports, and increased reserve requirements. MISO is expected to have sufficient resources, including firm imports, for normal summer peak demand. However, it can be challenging for MISO to meet above-normal peak demand if wind and solar resource output is lower than expected. Wind generator performance during periods of high demand is a key factor in determining whether there is sufficient electricity supply on the system or if external (non-firm) supply assistance is required to maintain reliability.
- **MRO-SaskPower:** Despite being primarily a winter-peaking area, Saskatchewan can face high electricity demand during hot summer weather conditions. Since 2023, both electricity demand and supply resources have increased, resulting in a 1.2% increase in reserve margin for the summer. Unanticipated generator outages that coincide with peak demand can result in insufficient reserves, a condition that operators will seek to alleviate through short-term transfers from neighbors and demand-side management.
- **NPCC-New England:** With the retirement of two natural-gas-fired generators at Mystic Generating Station in May 2024 (1,400 MW combined summer capacity), ISO New England will have less capacity this summer. This makes it more likely that ISO New England will need to resort to operating procedures for obtaining resources or non-firm supplies from neighboring areas during periods of above-normal peak demand or low-resource conditions. Summer heat waves that extend over the entire area can limit the availability of excess supplies and increase the risk of energy emergencies in New England.
- **Texas RE-ERCOT:** As a result of continued vigorous growth in both loads and solar and wind resources, there is a risk of emergency conditions in the summer evening hours when solar generation begins to ramp down. Contributing to the elevated risk is a potential need, under certain grid conditions, to limit power transfers from South Texas into the San Antonio region. These grid conditions can occur when demand is high and wind and solar output is low in specific areas, straining the transmission system and necessitating South Texas generation curtailments and potential firm load shedding to avoid cascading outages.
- **WECC-BC:** The peak demand forecast in the province of British Columbia has increased by over 600 MW since 2023 (7.4%), contributing to a drop in Anticipated Reserve Margin by over 10 percentage points. Much of the province is experiencing significant drought, and long-term precipitation deficits can challenge electricity production at some hydropower generators. Above-normal demand and low-resource conditions can result in the need for imports from neighboring areas. However, external assistance can be at risk during wide-area heat events.
- **WECC-CA/MX:** New solar and battery resources are contributing to higher on-peak reserve margins (46.7%, up over 11 percentage points since 2023) for the upcoming summer. Winter precipitation and snowpack have alleviated drought conditions across California, making more output from the area's hydropower resources available to balance variability in wind and solar output. Probabilistic assessments performed by WECC show that the risks of load loss are similar to Summer 2023, ranging from negligible to 0.8 loss of load hours (LOLH) depending on how much of the area's new solar and battery resources (totaling nearly 6 GW of nameplate capacity) are completed over the summer. The loss-of-load risk in this analysis occurs primarily under above-normal demand and low-resource conditions (e.g., low solar output, below-normal imports due to wide-area heat conditions or transmission limitations). Furthermore, risk is concentrated in the Baja (Mexico) portion of the WECC-CA/MX

[1] NERC's long-term, seasonal, and special reliability assessments are published on the Reliability Assessments web page.

assessment area. The assessment area has adequate resources for normal summer conditions.

- **WECC-SW:** Both forecasted peak demand and resources have risen since last summer, yielding a modest increase in the anticipated on-peak reserve margin (22.0%, up 2.5 percentage points since 2023.) The area has sufficient resources for normal summer demand. However, extreme demand or low resource output scenarios will likely require additional non-firm imports from neighboring areas, which may be unavailable during wide-area heat events. The ongoing severe drought in the Southwest increases the risk that extreme conditions could impact the BPS this summer.

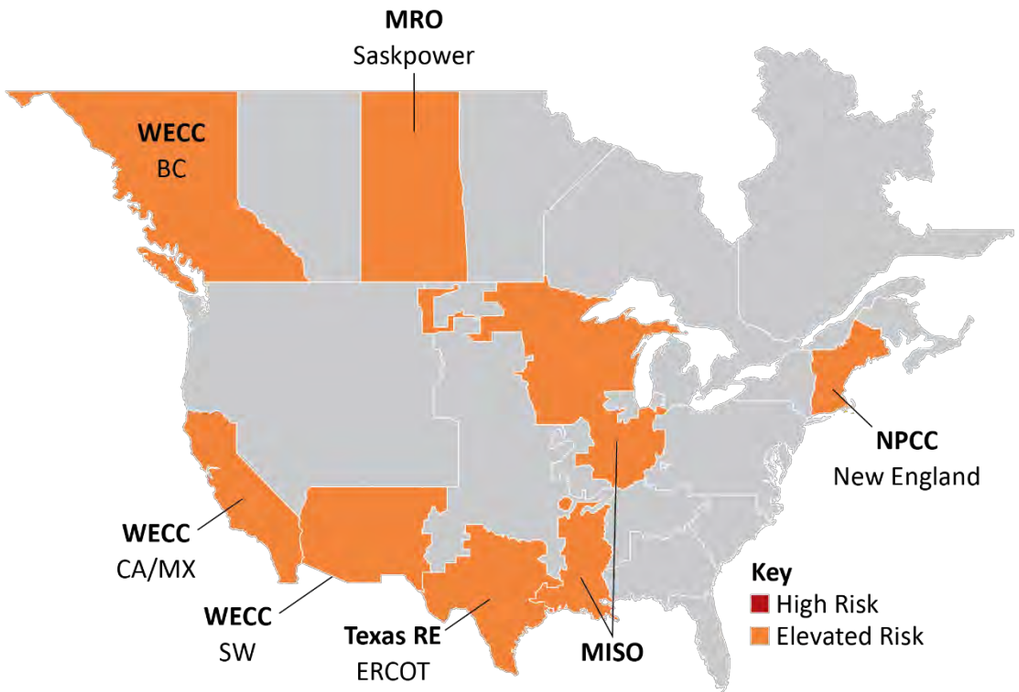


Figure 1: Summer Reliability Risk Area Summary

Seasonal Risk Assessment Summary	
High	Potential for insufficient operating reserves in normal peak conditions
Elevated	Potential for insufficient operating reserves in above-normal conditions
Normal	Sufficient operating reserves expected

New resources including 25 GW of nameplate solar capacity have been added to the BPS since last summer. Resource additions in assessment areas that were identified as at risk in the *2023 SRA* have largely outpaced rising demand forecasts and resulted in higher on-peak reserve margins. Four elevated-risk assessment areas from the *2023 SRA* are considered normal risk for the upcoming summer: NPCC-Ontario, SERC-Central, SPP, and WECC-NW. New firm transfer agreements, growth in DR, and postponed generator retirements are also contributing to an overall improved resource outlook for the upcoming summer. Details of each area are contained in the assessment area pages.

The findings in the *SRA* are consistent with conclusions reported in NERC's *2023 LTRA*. In assessing potential future electricity supply shortfalls over the 10-year horizon, NERC found that resource additions and delayed generator retirements have improved the outlook for 2024 in comparison to results reported in prior *LTRA*s. However, the *2023 LTRA* also found that a growing number of areas in North America face adequacy risks as early as 2025. NERC will publish the next *LTRA* in December 2024 based on demand forecasts, resource and transmission projections, and other information collected this year. NERC will also publish the 2024–2025 *Winter Reliability Assessment* in November to identify, assess, and report on BPS reliability issues for the next winter season.

Other Reliability Issues

- **Weather services are expecting above-average summer temperatures across much of North America, potentially creating challenging summer grid conditions.** Peak electricity demand in most areas is directly influenced by temperature. Above-average seasonal temperatures can contribute to high peak demand as well as an increase in forced outages for generation and some BPS equipment. Last summer brought record temperatures, extended heat waves, and wildfires to large parts of North America. Although few high-level energy emergency alerts were issued and no electricity supply disruptions occurred as a result of inadequate resources, operators at BAs, TOPs, and RCs faced significant challenges and drew upon procedures and protocols to obtain all available resources, manage system demand, and ensure that energy is delivered over the transmission network to meet the system demand. Additionally, load-serving entities and state and local officials in many parts of North America used mechanisms and public appeals to lower customer demand during periods of strained supplies. Operators should review lessons and experience from the prior summer and incorporate insights into their seasonal operations planning. The **Review of 2023 Capacity and Energy Performance** section describes actual demand and resource levels in comparison with NERC's *2023 SRA* and summarizes 2023 resource adequacy events.
- **Rising demand is challenging resource and transmission adequacy in several areas.** Most areas are forecasting increases in peak demand compared to last summer. The extent that demand forecasts have increased and the drivers affecting growth vary by area. In ERCOT,

SPP, and British Columbia, the increases are among the highest and build on similar growth from the prior year. New data centers and cryptocurrency mining facilities are contributing to higher demand forecasts in ERCOT this summer, and some of these loads participate in demand-side management programs that can offset their impacts (see **Evolving Demand-Side Management Programs**). While resource additions in Texas, primarily solar PV, are outpacing demand increases, energy risks are growing during the hours when solar output is diminished. Further, transmission development is straining to connect new resources and deliver electricity supplies to growing load areas.

- **Occurrences involving the unexpected tripping of inverter-based resources (IBR) during grid disturbances continue to spread, underscoring the need for operator vigilance in the near term and urgent industry action on long-term solutions.** The tripping of BPS-connected solar PV generating units during grid faults has caused sudden loss of generation resources (over wide areas in some cases). Industry experience with unexpected tripping of BPS-connected solar PV generation units can be traced back to the 2016 Blue Cut fire in California. Similar events have occurred as recently as Summer 2023.[2] New event reports published by NERC analyzing the Southwest Utah disturbance (April 2023) and the California Battery Energy Storage disturbances (April and May 2022) illustrate that the reliability concern extends to more geographic areas and more than just solar PV resources. IBRs include most solar and wind generation as well as new battery energy storage systems (BESS) or hybrid generation and account for over 70% of the new generation in development for connecting to the BPS. IBRs respond to disturbances and dynamic conditions based on programmed logic and inverter controls. A common thread with these tripping events is the lack of IBR ride-through capability that causes a minor system disturbance to become a major disturbance. In March 2023, NERC issued the *Inverter-Based Resource Performance Issues Alert* to Generator Owners (GO) of Bulk Electric System (BES) solar PV generating resources.[3] As a Level 2 alert, it contains recommended actions for GOs of grid-connected solar PV resources, including steps to coordinate protection and controller settings, so that the resources will remain reliable during grid disturbances. NERC's comprehensive Inverter-Based Resources Strategy and FERC Order No. 901 describe additional steps for the ERO and industry to ensure that IBRs operate reliably and that the system is planned with due consideration for their characteristics.[4,5]

- **Stored supplies of natural gas are at high levels, but continued vigilance is needed to ensure the reliability of fuel delivery to natural-gas-fired-generators.**[6] The natural gas supply and infrastructure is vitally important to electric grid reliability, particularly as variable energy resources satisfy more of our energy needs. Fuel supply and delivery infrastructure must be capable of meeting the ramp rates of natural-gas-fired generators as they balance the system when wind and solar generation output declines. No specific reliability issues have been identified for the upcoming summer, but Reliability Coordinators (RC) and Balancing Authorities (BA) should be cognizant of natural gas supply infrastructure outage and maintenance plans that could affect generators in their areas.

- **Expanded demand-side management programs are an added resource for operators that should be carefully considered in operating plans and monitored during peak demand periods.** Formal DR programs involving commercial and industrial customers that have agreements with their load-serving entities to curtail load during high-demand periods have grown in many assessment areas. Additionally, some entities have launched programs with retail customers that also provide operator-controlled demand-side management capabilities. Operators will need to give special attention to new or expanded demand-side management programs in their planning if they are unfamiliar with protocols or uncertain about the amount of load relief that will be realized. These new mechanisms and protocols for controlling demand can support operating reliability and energy adequacy needs when they are effectively implemented and monitored.

- **Supply chain issues are delaying some new resource and transmission projects, raising concerns that some may not be completed prior to peak summer conditions.** Lead times for transformers, circuit breakers, transmission cables, switchgears, and insulators have increased significantly since 2020. Additionally, PV panels are more difficult to procure. These longer lead times can affect new project construction, existing asset upgrades, pre-seasonal maintenance, and the interconnection of new resources and customers. Long-term mitigation strategies include lengthening ongoing construction timelines and ordering surplus inventory in advance. In the near term, supply chain issues can exacerbate concerns in elevated risk areas and add operating challenges for the summer across the BPS. Should project delays emerge, affected GOs and Transmission Owners (TO) must communicate changes to BAs, Transmission Operators (TOP), and RCs so that impacts are understood and steps are taken to reduce risks of capacity deficiencies or energy shortfalls.

- **Wildfire risk areas cover a smaller portion of North America at the start of summer, lowering the likelihood that the BPS will be affected by fire conditions.** At the start of summer, Canadian wildfire information system officials assess that there is potential for above-average fire activity over a large region that extends from British Columbia to northwest Manitoba

[2] See the ERO's extensive IBR event reporting here: NERC Major Event Reports
[3] NERC Alert: Inverter Based Resource Performance Issues
[4] NERC IBR Activities
[5] FERC Order No. 901 - Final Rule Reliability Standards to Address Inverter-Based Resources
[6] Short-Term Energy Outlook - U.S. Energy Information Administration (EIA)

and includes Alberta and Saskatchewan. In the United States, Climate Prediction Center and Predictive Services outlooks for early summer indicate that above-normal significant fire potential is limited to portions of the U.S. Southwest and West Texas.[7] Nonetheless, wildfire risk in North America typically increases in later summer months as hotter and drier weather increases fire potential. BPS operation can be impacted in areas where wildfires are active as well as areas where there is heightened risk of wildfire ignition due to weather and ground conditions.

Recommendations

To reduce the risk of electricity shortfalls on the BPS this summer, NERC recommends the following:

- RCs, BAs, and TOPs in the elevated risk areas identified in the key findings should take the following actions:
  - Review seasonal operating plans and the protocols for communicating and resolving potential supply shortfalls in anticipation of potentially extreme demand levels
  - Employ conservative generation and transmission outage coordination procedures commensurate with long-range weather forecasts to ensure adequate resource availability
  - Engage state or provincial regulators and policymakers to prepare for efficient implementation of demand-side management mechanisms called for in operating plans
- GOs with solar PV resources should implement recommendations in the IBR performance issues alert that NERC issued in March 2023.[8]
- State regulators and industry should have protocols in place at the start of summer for managing emergent requests from generators for air-quality restriction waivers. If warranted, U.S. Department of Energy (DOE) action to exercise emergency authority under the Federal Power Act (FPA) section 202(c) may be needed to ensure that sufficient generation is available during extreme weather conditions.

[7] NIFC North American Outlook

[8] Industry Recommendation: Inverter-Based Resource Performance Issues

Discussion

Summer Temperature and Drought Forecasts

Peak electricity demand in most areas is directly influenced by temperature. Weather officials are expecting above-normal temperatures for much of the United States and Canada (see **Figure 2**). In addition, drought conditions continue across much of Canada and the U.S. Southwest, resulting in unique challenges to area electricity supplies and potential impacts on demand.[9] Assessment area load forecasts account for many years of historical demand data, often up to 30 years, to predict summer peak demand and prepare for more extreme conditions. Above-average seasonal temperatures can contribute to high peak demand as well as an increase in forced outages for generation and some BPS equipment. Effective preseason maintenance and preparations are particularly important to BPS reliability in severe or prolonged periods of above-normal temperatures.

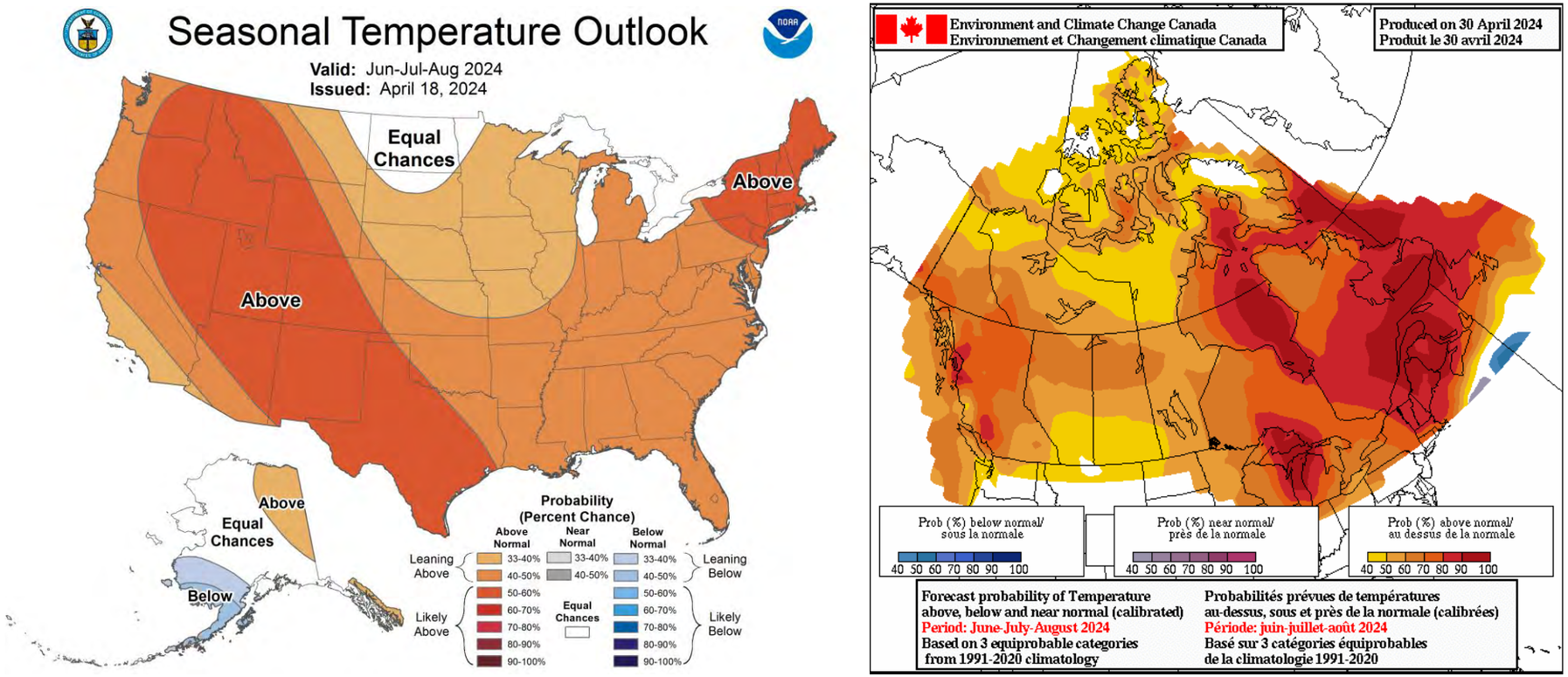


Figure 2: United States and Canada Summer Temperature Outlook[10]

[9] See North American Drought Monitor: https://www.ncdc.noaa.gov/temp-and-precip/drought/nadm/maps

[10] Seasonal forecasts obtained from U.S. National Weather Service and Natural Resources Canada: https://www.cpc.ncep.noaa.gov/products/predictions/long_range/ and https://weather.gc.ca/saisons/prob_e.html

Risk Assessment Discussion

NERC assesses the risk of electricity supply shortfall in each assessment area for the upcoming season by considering Planning Reserve Margins, seasonal risk scenarios, probability-based risk assessments, and other available risk information. NERC provides an independent assessment of the potential for each assessment area to have sufficient operating reserves under normal conditions as well as above-normal demand and low-resource output conditions selected for the assessment. A summary of the assessment approach is provided in Table 1.

Table 1: Seasonal Risk Assessment Summary

Category	Criteria[1]
High Potential for insufficient operating reserves in normal peak conditions	• Planning Reserve Margins do not meet Reference Margin Levels; or • Probabilistic indices exceed benchmarks (e.g., LOLH of 2.4 hours over the season); or • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **normal peak-day demand and outage scenarios**[2]
Elevated Potential for insufficient operating reserves in above-normal conditions	• Probabilistic indices are low but not negligible (e.g., LOLH above 0.1 hours over the season); or • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **extreme peak-day demand with normal resource scenarios** (i.e., typical or expected outage and derate scenarios for conditions);[2] or • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **normal peak-day demand with reduced resources** (i.e., extreme outage and derate scenarios)[3]
Normal Sufficient operating reserves expected	• Probabilistic indices are negligible • Analysis of the risk hour(s) indicates resources will be sufficient to meet operating reserves under normal and extreme peak-day demand and outage scenarios[4]

Table Notes:
[1]The table provides general criteria. Other factors may influence a higher or lower risk assessment.
[2]**Normal resource scenarios** include planned and typical forced outages as well as outages and derates that are closely correlated to the extreme peak demand.
[3]**Reduced resource scenarios** include planned and typical forced outages and low-likelihood resource scenarios, such as extreme low-wind scenarios, low-hydro scenarios during drought years, or high thermal outages when such a scenario is warranted.
[4]Even in normal risk assessment areas, extreme demand and extreme outage scenarios that are not closely linked may indicate risk of operating reserve shortfall.

Assessment of Planning Reserve Margins and Operational Risk Analysis

Anticipated Reserve Margins, which provide the Planning Reserve Margins for normal peak conditions, as well as reserve margins for seasonal risk scenarios of more extreme conditions are provided in Table 2.

Table 2: Seasonal Risk Scenario On-Peak Reserve Margins

Assessment Area	Anticipated Reserve Margin	Anticipated Reserve Margin with Typical Outages	Anticipated Reserve Margin with Higher Demand, Outages, Derates in Extreme Conditions
MISO	26.1%	8.7%	-6.3%
MRO-Manitoba	15.7%	11.7%	5.1%
MRO-SaskPower	30.3%	26.5%	10.3%
MRO-SPP	27.8%	17.6%	-2.5%
NPCC-Maritimes	44.9%	34.5%	6.0%
NPCC-New England	15.9%	6.3%	3.3%
NPCC-New York	30.4%	11.4%	4.0%
NPCC-Ontario	26.2%	26.2%	19.8%
NPCC-Québec	44.1%	23.8%	18.2%
PJM	27.6%	17.9%	9.0%
SERC-C	24.3%	14.9%	14.7%
SERC-E	22.2%	16.3%	10.8%
SERC-FP	26.3%	19.3%	12.3%
SERC-SE	44.6%	41.1%	34.9%
TRE-ERCOT	25.6%	19.2%	11.5%
WECC-AB	30.5%	28.1%	8.6%
WECC-BC	18.8%	18.7%	-5.6%
WECC-CA/MX	46.7%	40.8%	5.4%
WECC-NW	35.5%	29.7%	1.1%
WECC-SW	22.0%	12.9%	-10.8%

Seasonal risk scenarios for each assessment area are presented in the **Regional Assessments Dashboards** section. The on-peak reserve margin and seasonal risk scenario charts in each dashboard provide potential summer peak demand and resource condition information. The reserve margins on the right side of the dashboard pages provide a comparison to the previous year's assessment. The seasonal risk scenario charts present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. The assessment areas determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized in the seasonal risk scenario charts; more information about these dashboard charts is provided in the **Data Concepts and Assumptions** section.

The seasonal risk scenario charts can be expressed in terms of reserve margins: In **Table 2**, each assessment area's Anticipated Reserve Margins are shown alongside the reserve margins for a typical generation outage scenario (where applicable) and the extreme demand and resource conditions in their seasonal risk scenario.

Highlighted in **orange** are the areas identified as having resource adequacy or energy risks for the summer in the **Key Findings** section's discussion. The typical outage reserve margin includes anticipated resources minus the capacity that is likely to be in maintenance or forced outage at peak demand. If the typical maintenance or forced outage margin is the same as the Anticipated Reserve Margin, it is because an assessment area has already factored typical outages into the anticipated resources. The extreme conditions margin includes all components of the scenario and represents the most severe operating conditions of an area's scenario. Note that any reserve margin below zero indicates that the resources fall below demand in the scenario.

In addition to the peak demand and seasonal risk hour scenario charts, the assessment areas provided a resource adequacy risk assessment that was probability-based for the summer season. Results are summarized in **Table 3**. The risk assessments account for the hour(s) of greatest risk of resource shortfall. For most areas, the hour(s) of risk coincide with the time of forecasted peak demand; however, some areas incur the greatest risk at other times based on the varying demand and resource profiles. Various risk metrics are provided and include loss of load expectation (LOLE), LOLHs, expected unserved energy (EUE), and the probabilities of energy emergency alert (EEA) occurrence.

Energy Emergency Alerts

Extreme generation outages, low resource output, and peak loads similar to those experienced in wide-area heat events and the heat domes experienced in western parts of North America during the last three summers are ongoing reliability risks in certain areas for Summer 2024. When forecasted resources in an area fall below expected demand and operating reserve requirements, BAs may need to employ operating mitigations or EEAs to obtain the capacity and energy necessary for reliability. A description of each EEA level is provided below.

Energy Emergency Alert Levels

EEA Level	Description	Circumstances
EEA 1	All available generation resources in use	• The BA is experiencing conditions in which all available generation resources are committed to meet firm load, firm transactions, and reserve commitments and is concerned about sustaining its required contingency reserves. • Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
EEA 2	Load management procedures in effect	• The BA is no longer able to provide its expected energy requirements and is an energy-deficient BA. • An energy-deficient BA has implemented its operating plan(s) to mitigate emergencies. • An energy-deficient BA is still able to maintain minimum contingency reserve requirements.
EEA 3	Firm load interruption is imminent or in progress	• The energy-deficient BA is unable to meet minimum contingency reserve requirements.

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
MISO	NERC 2022 Probabilistic Assessment (2022 ProbA)	The 2022 ProbA results found 187 MWh EUE for Summer 2024 and <1 hour of LOLH. However, MISO has more resources and higher reserves for the summer than were considered in the 2022 ProbA, which should result in lower risk.
MRO-Manitoba	Verification of NERC 2022 Probabilistic Assessment (2022 ProbA)	The 2022 ProbA results indicate 29 MWh per year of EUE for 2024.
MRO-SaskPower	Probability-based capacity adequacy assessment	Results indicate that the expected number of hours with operating reserve deficiency for the 2024 summer season (June–September) is 0.68 hours. June is the month with highest risk.
MRO-SPP	Statistical analysis of the Summer 2022 real-time data and operating procedures	Potential risk of using operating reserves and EEA 1 or EEA 2 is 1 day per summer. Risk of EEA3 is 0.2 days per summer. Risk is associated with low wind generation output levels or unanticipated generation outages in combination with high-load periods.
NPCC	NPCC conducted an all-hour probabilistic assessment that consisted of a base case and several more severe scenarios examining low resources, reduced imports, and higher loads. The highest peak load scenario has a 7% probability of occurring.	NPCC Regional Entity assesses that there will be an adequate supply of electricity across the Regional Entity this summer. Necessary strategies and procedures are in place to deal with operational challenges and emergencies as they may develop. Preliminary results of the probabilistic analysis by assessment area are below. [NPCC anticipates releasing the assessment in early May].
NPCC-Maritimes		NPCC's assessment results indicate that Maritimes is unlikely to experience resource shortages that would require additional imports or operating procedures this summer. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios, including the severe low-likelihood cases.
NPCC-New England		NPCC's assessment results indicate that ISO-New England (ISO-NE) could experience resource shortages during high-demand and low-resource conditions and require limited use of operating procedures for mitigation. In NPCC's probabilistic assessment, the reduced resource case with the highest peak load scenario resulted in New England having a small estimated cumulative LOLE risk (0.66 days/summer) with associated LOLHs (2.7 hours/summer) and EUE (1,476 MWh/summer) with the highest risk occurring in June. This scenario is based exclusively on the two highest load levels with a 7% chance of occurring and a low-resource case consisting of extended summer maintenance across NPCC and reduced imports from PJM. Negligible cumulative LOLE (<0.022 days/summer), LOLH (<0.08hours/summer), and EUE (<17 MWh/summer) risks were estimated over the summer May–September period for the other scenarios modeled.
NPCC-New York		NPCC's assessment results indicate that New York ISO (NYISO) could experience resource shortages during high-demand conditions and require limited use of operating procedures for mitigation. In NPCC's probabilistic assessment, the highest peak load scenarios resulted in New York having a small estimated cumulative LOLE risk (1.6 days/summer) with associated LOLHs (5.9 hours/summer) and EUE (5,460 MWh/summer) with the highest risk occurring in July and August. Scenarios are based exclusively on the two highest load levels with a 7% chance of occurring. Negligible cumulative LOLE (<0.023 days/summer), LOLH (<0.07 hours/summer), and EUE (39 MWh/summer) were estimated over the summer period for the other scenarios modeled. Furthermore, the New York State Reliability Council conducts an annual study to determine the installed reserve margin (IRM) necessary to meet the 1 day in 10 years Loss of LOLE criterion. NYISO has procured capacity for the upcoming summer to meet the IRM requirement.

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
NPCC-Ontario		NPCC's assessment results indicate that Ontario is unlikely to experience resource shortages that would require additional imports or operating procedures this summer. In NPCC's probabilistic assessment, the reduced resource case with the highest peak load scenario resulted in Ontario having a negligible cumulative LOLE risk (0.03 days/summer) with associated LOLHs (0.07 hours/summer) and EUE (33 MWh/summer) with the highest risk occurring in August. This scenario is based exclusively on the two highest load levels with a 7% chance of occurring and a low-resource case consisting of additional summer maintenance and low hydroelectric output. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer for the other scenarios modeled.
NPCC-Québec		NPCC's assessment results indicate that Québec is unlikely to experience resource shortages that would require additional imports or operating procedures this summer. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios, including the severe low-likelihood cases.
PJM	Based on 2023 PJM Reserve Requirement Study (RRS)	PJM is expecting a low risk of resources falling below required operating reserves. PJM forecasts a 29% IRM, well above the target of 17.7%. The RRS analyzed a wide range of load scenarios (low, regular, and extreme) as well as multiple scenarios for system-wide unavailable capacity due to forced outages, maintenance outages, and ambient derations. Due to the low penetration of variable energy resources in PJM relative to PJM's peak load, the hour with most loss of load risk remains the hour with highest forecasted demand.
SERC	Verification of NERC 2022 ProbA Results	The 2022 base case results indicated adequate resources for the SERC Regional Entity as a whole with an observed LOLE of 0.01 days/summer for 2024.
SERC-Central		Probabilistic analysis indicates no risk for resource shortfall.
SERC-East		Probabilistic analysis shows low risk for July and August with EUE of 2.38 MWh and LOLH 0.005 hours.
SERC-Florida Peninsula		SERC probabilistic analysis indicates no risk of resource shortfall.
SERC-Southeast		Probabilistic analysis indicates almost no risk of resource shortfall.
Texas RE-ERCOT	ERCOT probabilistic assessment using the Probabilistic Reserve Risk Model	The simulation indicates an elevated risk of having to declare an EEA during evenings on peak load days in August—the forecasted summer peak load month. The probability of declaring an EEA is 18.4% during the highest risk hour. The probability of firm load shedding is 14.6% during the highest risk hour. The model accounts for the risk of triggering the curtailment of coastal region wind generation due to transmission system constraints.
WECC	WECC performed a probabilistic assessment for Summer 2024 based on demand and resource forecasts provided by load-serving entities.	Resource adequacy remains a critical risk in the Western Interconnection and continues to challenge industry planners, operators, regulators, and partners. Resource adequacy risks over the medium and long terms have increased significantly compared to last year's assessment. Three risks merit particular attention: increasing variability, rate of demand growth and uncertainty of future load patterns, and the pace of new resource growth necessary to meet future energy demand.[11]
WECC-AB		Alberta is expected to have sufficient resource availability to meet demand and cover reserves on the peak hour at 5:00 p.m. under a summer peak defined at the 90th percentile with any combination or accumulation of derates.

[11] See 2023 Western Assessment of Resource Adequacy.pdf (wecc.org)

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
WECC-BC		British Columbia is expected to have sufficient resource availability to meet reserves at the peak demand hour (5:00–6:00 p.m.) under most conditions. However, above-normal demand that coincides with low hydro output could result in a reserve shortage. This evaluation considers a 1-in-10 probability (90th percentile) level for peak demand and a combination of resource derates including low hydro output.
WECC-CA/MX		WECC-CA/MX is projected to have negligible-to-low amounts of LOLH (<1 hours) this summer, primarily forecast in the Baja (Mexico) part of CA/MX. Resources are sufficient to meet demand and cover reserves on the peak demand hour at 5:00 p.m. under a summer peak demand defined at the 90th percentile with any combination or accumulation of resource derates. There is increased risk of insufficient reserves at later hours (up to 7:00 p.m.) due to the variability of energy resource output. Imports to the area are required to cover these risk periods.
WECC-NW		The Northwest is expected to have sufficient resource availability to meet reserves at the peak demand hour at 5:00 p.m. under a summer peak defined at the 90th percentile with any combination or accumulation of derates.
WECC-SW		Results of WECC's probabilistic analysis indicate that the WECC-SW assessment area is projected to have negligible LOLH and EUE this summer under assessed scenarios. NERC's assessment of elevated risk is influenced by the deterministic risk scenario on page 36. The scenario shows that the assessment area would have insufficient resources to meet operating reserve requirements at a 90/10 demand level with typical generation outages and a scenario involving low-resource output and normal peak demand.

Evolving Demand-Side Management Programs

Demand-side management programs are expanding in many assessment areas, providing operators with additional resources to reduce electricity demand during periods when electricity supplies may not be sufficient. **Figure 3** shows the assessment areas with a DR exceeding 1.5% of the total internal demand. Formal DR programs involving commercial and industrial customers that have agreements with their load-serving entities to curtail load during high demand periods have grown in many assessment areas (see **Demand and Resource Tables**). Additionally, some entities have launched programs with retail customers that provide similar operator-controlled demand-side management capabilities. Programs in use by the independent system operators in Texas and the province of Ontario, discussed below, provide examples of the types of DR programs in use this summer and the contributions to meeting operating reliability and resource adequacy needs.

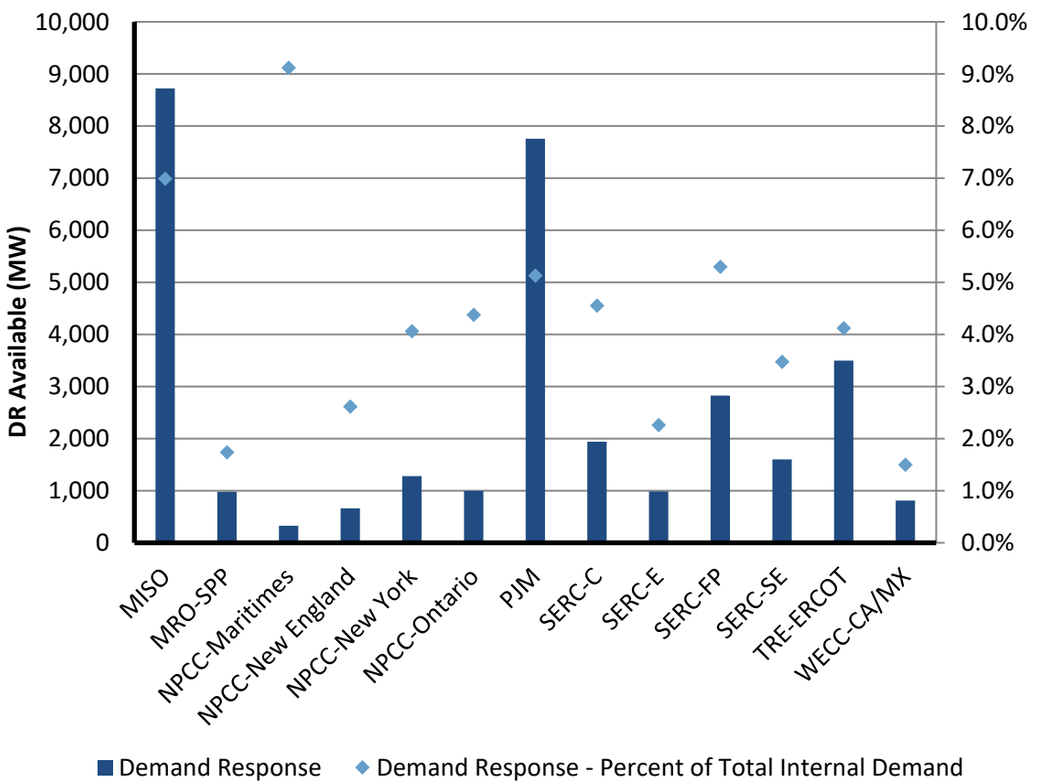


Figure 3: Demand Response in Assessment Areas Exceeding 1.5% Total Internal Demand

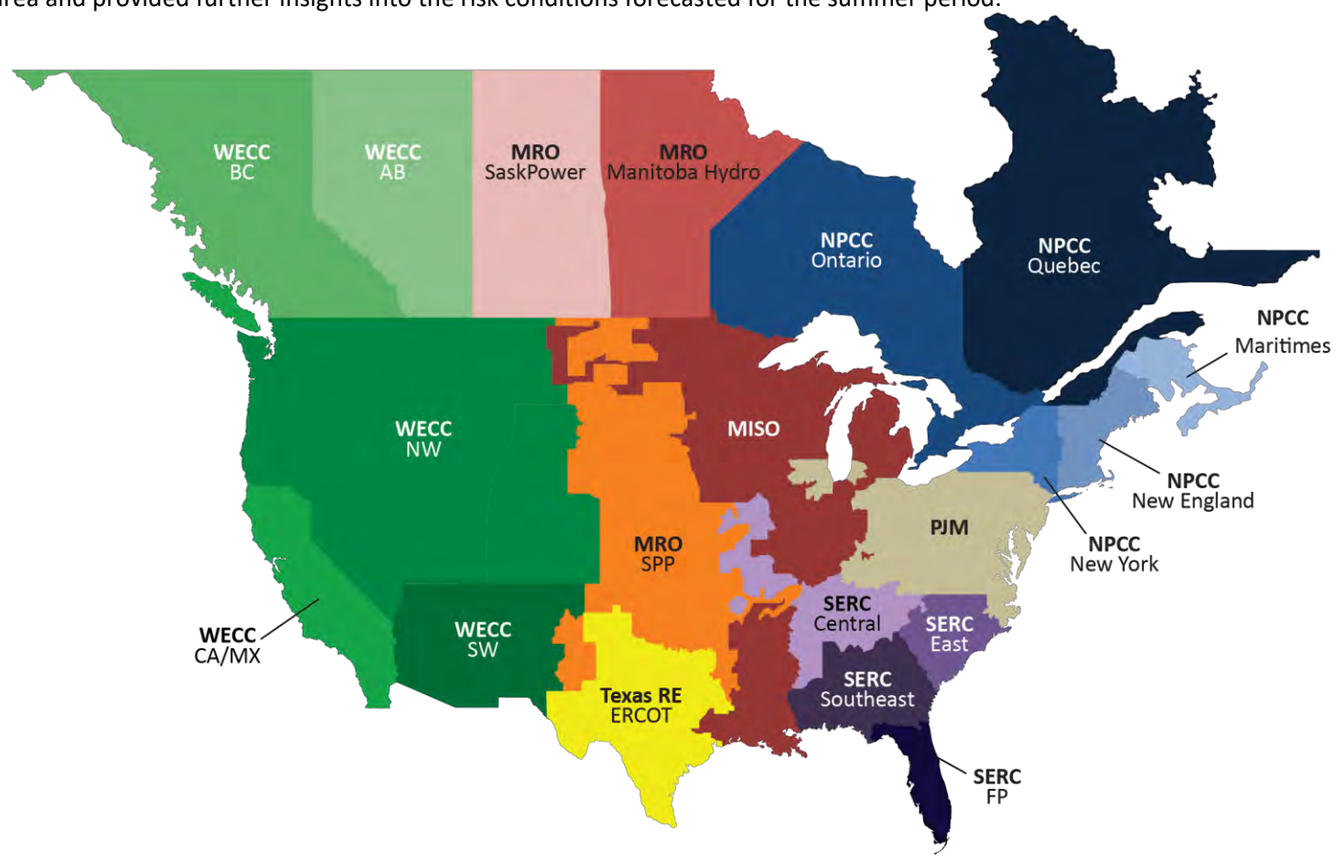
In ERCOT, nearly 3,500 MW of DR resources are expected for this summer, the equivalent of 4% of normal peak demand. Resources come from various programs, including several that are administered by ERCOT as well as those administered by other entities.

- ERCOT's controllable load resources (CLR) consist of large loads (e.g., data centers) and battery charging systems that can be dispatched by ERCOT to provide frequency regulation and short-notice resources for managing wind and solar ramps; 600 MW of CLRs are registered.
- Non-controllable load resources (NCLR) consist of "blocky" loads with both a 10-minute ramp capability for manual deployments and automatic deployment through underfrequency relay. NCLRs participate in ERCOT's Responsive Reserve Service market. ERCOT expects just over 1,100 MW of participation for the highest reserve risk hours for the upcoming summer.
- Some DR resources participate in ERCOT's Emergency Response Service (ERS), along with distributed generation. ERCOT's ERS consists of 10- and 30-minute-ramping DR and distributed generation that can first be deployed when physical responsive capability (PRC) drops to 3,000 MW to provide a contingency reserve. During the 2023 program year, ERS was deployed twice, once on August 17, and again on September 6 when ERCOT's PRC dropped below 3,000 MW. ERCOT expects approximately 1,000 MW to participate in ERS for the highest reserve risk hours for the upcoming summer.
- Transmission and distribution service provider (TDSP) load management programs provide price incentives for voluntary load reductions from commercial, industrial, and, most recently, residential loads during EEA Level 2 events. These programs have historically only been available for the months of June through September from 1:00–7:00 p.m. on weekdays (except holidays) and deployed via ERCOT instruction pursuant to agreements between ERCOT and the TDSPs. ERCOT forecasts that these programs can provide 330 MW in demand relief this summer. In addition, ERCOT Nodal Protocols allow ERCOT to instruct TDSPs to reduce customer load by using existing, in-service distribution voltage reduction measures to avoid an EEA. Conservation voltage reduction (CVR) can lower demand by nearly 575 MW.
- ERCOT accounts for load-reduction programs administered by retail entities in its load forecast. The 4-Coincident Peak (4CP) Load Reduction program incentivizes customers to reduce load during four anticipated 15-minute peak-load intervals, one each across the summer months of June, July, August, and September. The amount of load reduction for the four 4CP days in 2023 averaged 4,674 MW. Additionally, retail entities offer a variety of price-response programs that are factored into ERCOT's load forecast.

In the province of Ontario, the Independent Electricity System Operator (IESO) has expanded DR programs for summer. Overall, this summer, the effective capacity of Ontario's DR programs is 996 MW, the equivalent of 4% of normal peak demand. This includes 805 MW of DR from the capacity auction. The Peak Perks program, launched in June 2023, will contribute 92 MW of effective capacity this summer through enrolled residential customers with smart thermostats that may be controlled at peak times. The IESO also launched the Interruptible Rate Pilot in July 2023. The pilot is designed to provide large-load customers with an interruptible rate in exchange for agreeing to interrupt demand during up to 15 event periods, each up to four hours long. The pilot will run for a three-year period and has two participants that will provide 76 MW of interruptible demand.

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six Regional Entities on an assessment area basis. Guidelines and definitions are in the **Data Concepts and Assumptions** table. On-peak reserve margin bar charts show the Anticipated Reserve Margin compared to a Reference Margin Level that is established for the areas to meet resource adequacy criteria. Prospective Reserve Margins can give an indication of additional on-peak capacity but are not used for assessing adequacy. The operational risk analysis shown in the following regional assessments dashboard pages provides a deterministic scenario for understanding how various factors that affect resources and demand can combine to impact overall resource adequacy. For each assessment area, there is a risk-period scenario graphic; the left **blue** column shows anticipated resources (from the **Demand and Resource Tables**), and the **orange** column at the right shows the two demand scenarios of the normal peak net internal demand (from the **Demand and Resource Tables**) and the extreme summer peak demand determined by the assessment area. The middle **red** or **green** bars show adjustments that are applied cumulatively to the anticipated resources. Adjustments may include reductions for typical generation outages (maintenance and forced not already accounted for in anticipated resources) and additions that represent the quantified capacity from operational tools (if any) that are available during scarcity conditions but have not been accounted for in the *SRA* reserve margins. Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The cumulative effects from extreme events are also factored in through additional resource derates or low-output scenarios. In addition, results from a probability-based resource adequacy assessment are shown in the Highlights section of each dashboard. Methods varied by assessment area and provided further insights into the risk conditions forecasted for the summer period.



MISO *(Midcontinent Independent System Operator)*
PJM

MRO – Midwest Reliability Organization
- MRO-Manitoba Hydro
- MRO-SaskPower
- MRO-SPP

NPCC – Northeast Power Coordinating Council
- NPCC-Maritimes
- NPCC-New England
- NPCC-New York
- NPCC-Ontario
- NPCC-Québec

SERC – SERC Reliability Corporation
- SERC-Central
- SERC-East
- SERC-Southeast
- SERC-Florida Peninsula

Texas RE – Texas Reliability Entity
- Texas RE-ERCOT *(Electric Reliability Council of Texas)*

WECC
- WECC-AB *(Alberta)*
- WECC-BC *(British Colombia)*
- WECC-CA/MX *(California/Mexico)*
- WECC-NW *(Northwest)*
- WECC-SW *(Southwest)*



MISO

MISO is a not-for profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency. MISO manages energy, reliability, and operating reserve markets that consist of 36 local BA and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three Regional Entities, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

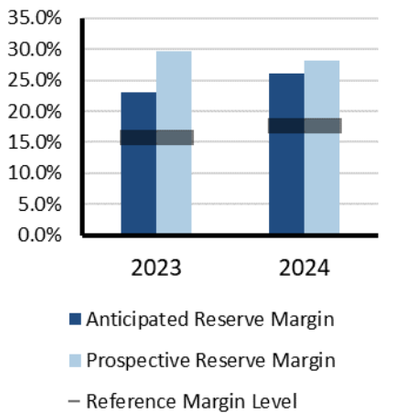
Highlights

- Demand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output. MISO's resources are projected to be higher than in Summer 2023 while net internal demand decreased slightly. With increased resource availability for this summer, Anticipated Reserve Margin (ARM) of 31.6% (on an installed capacity basis) is higher than last summer's ARM of 23%.
- MISO conducted its annual probabilistic LOLE analysis and determined that a 2024 Reference Margin Level (RML) of 17.7% results in an LOLE of 1 day in 10 years. MISO's RML increased from 15.9% in 2023 to 17.7% in 2024 based on the summer seasonal capacity construct. A methodology change in the Planning Resource Auction (PRA) requesting GOs' seasonally corrected Generator Verification Test Capacity (GVTC), updated seasonal forced outage rates, and updated annualized planned maintenance outage rates as well as information on new units, retirements, suspensions, and changes in the resource mix contributed to the increase in reserve margin for the 2024 summer. Comparing the increased ARM to the lower RML indicates improved reliability from the LOLE base case at 1 day in 10 years.
- Performance of wind generators during periods of high electricity demand is a key factor in determining whether system operators need to employ operating mitigations, such as maximum-generation declarations and energy emergencies. MISO has over 31,000 MW of installed wind capacity; however, the historically based on-peak capacity contribution is 5,616 MW.

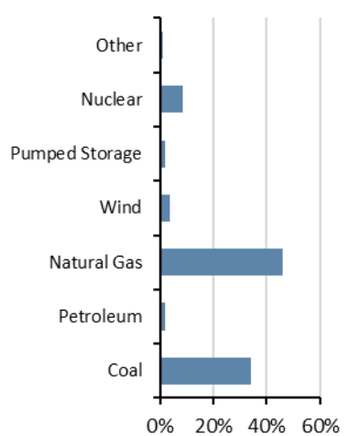
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and extreme generator outage conditions could result in the need to employ operating mitigations (e.g., load-modifying resources and energy transfers from neighboring systems) and EEAs. Emergency declarations that can only be called upon when available generation is at maximum capability are necessary to access load-modifying resources (DR) when operating reserve shortfalls are projected.

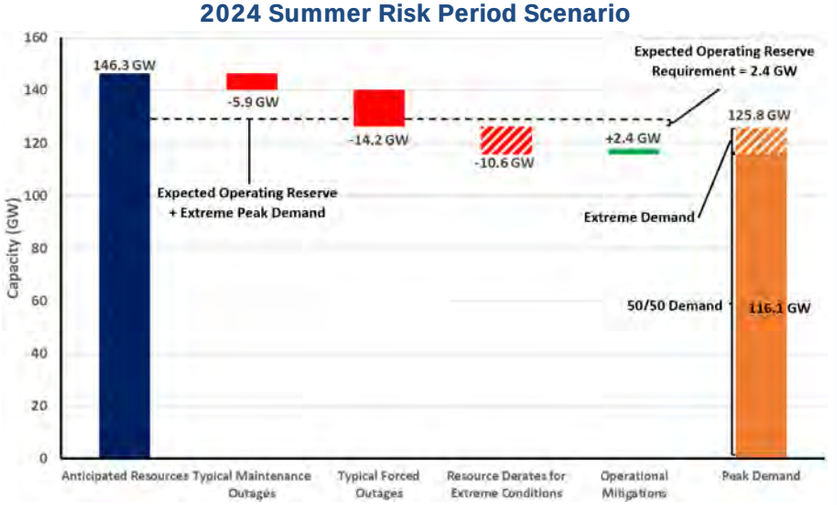
On-Peak Reserve Margin



On-Peak Fuel Mix



2024 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

Maintenance Outages: Rolling five-year summer average of maintenance and planned outages

Forced Outages: Five-year average of all outages that were not planned

Extreme Derates: Maximum historical generation outages

Operational Mitigations: A total of 2.4 GW capacity resources available during extreme operating conditions



MRO-Manitoba Hydro

Manitoba Hydro is a provincial Crown corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro is a leader in providing renewable energy and clean-burning natural gas. Manitoba Hydro provides electricity to approximately 608,500 electric customers in Manitoba and natural gas to approximately 293,000 customers in southern Manitoba. Its service area is the province of Manitoba, which is 251,000 square miles. Manitoba Hydro is winter peaking. Manitoba Hydro is its own Planning Coordinator (PC) and BA. Manitoba Hydro is a coordinating member of MISO, which is the RC for Manitoba Hydro.

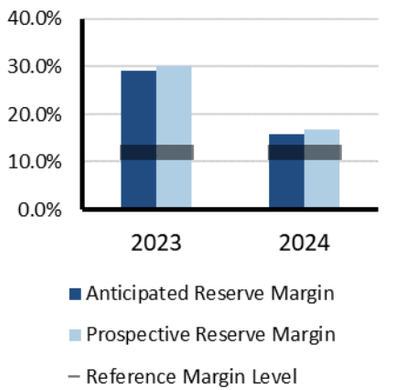
Highlights

- Manitoba Hydro is not anticipating any operational challenges and/or emerging reliability issues for Summer 2024.
- ARM has fallen since Summer 2023 due to higher peak demand forecast, more generator planned maintenance outages, and an increase in net firm capacity transfers. Nonetheless, ARM exceeds the 12% RML.
- Manitoba Hydro is experiencing below-average water supply conditions. However, above-average late-winter snowfall will favorably impact spring runoff. The Manitoba Hydro system is designed and operated such that reliable operations can be maintained under extreme drought. Manitoba Hydro expects to reliably supply its internal demand and export obligations even if drought continues through 2024/25.
- All units at Keeyask Generating Station have commercial operation status.

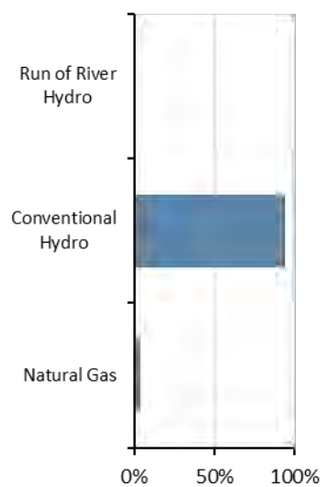
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

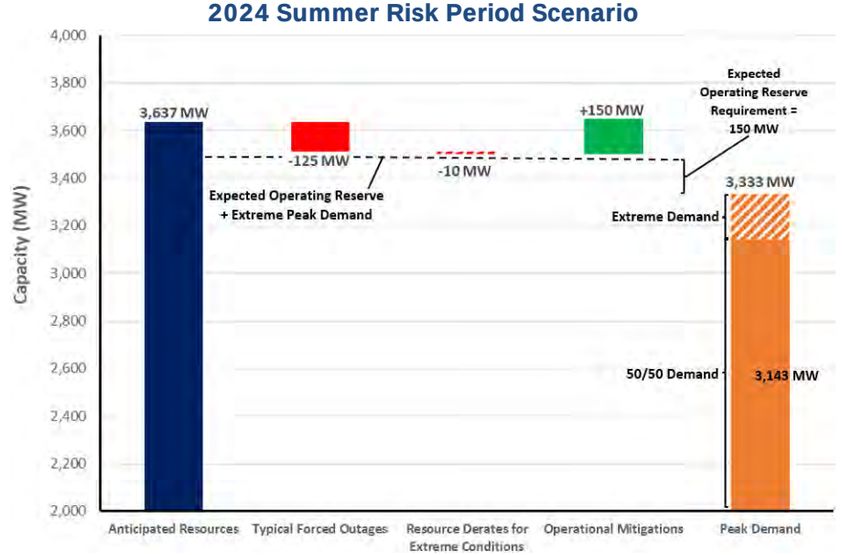
On-Peak Reserve Margin



On-Peak Fuel Mix



2024 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: (50/50) Demand with allowance for extreme demand based on extreme summer weather scenario of 35.4 C (96 F)

Forced Outages: Typical forced outages

Extreme Derates: Summer wind capacity accreditation of 18.1% of nameplate rating based on MISO seasonal analysis

Normal hydro generation expected for this summer.

Operational Mitigations: Utilize Curtailable Rate Program to manage peak demand; utilize operating reserve if additional measures required



MRO-SaskPower

MRO-SaskPower is an assessment area in the Saskatchewan province of Canada. The province has a geographic area of 651,900 square kilometers (251,700 square miles) and a population of approximately 1.1 million. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the PC and RC for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial Crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan BES and its Interconnections.

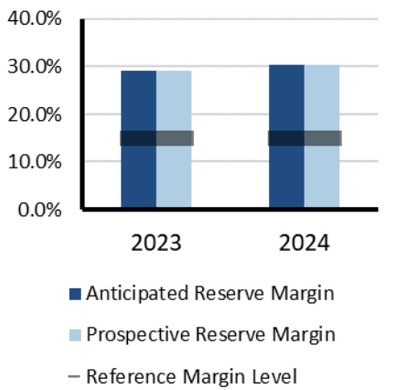
Highlights

- Despite being primarily a winter-peaking area, Saskatchewan also faces significant electricity demand in the summer during extremely hot weather conditions.
- SaskPower collaborates annually with Manitoba Hydro for a summer joint operating study, incorporating inputs from the Western Area Power Administration (WAPA) and Basin Electric to develop operational guidelines addressing any identified issues.
- The probability of experiencing a shortage in operating reserves during peak load periods, or EEAs, may increase if significant generation forced outages happen at the same time as planned maintenance outages during the high-demand months of June through September.
- If extreme thermal conditions align with significant generation outages, SaskPower will deploy available DR programs, engage in short-term power transfers from neighboring utilities, and implement temporary load interruptions as necessary to mitigate the situation.

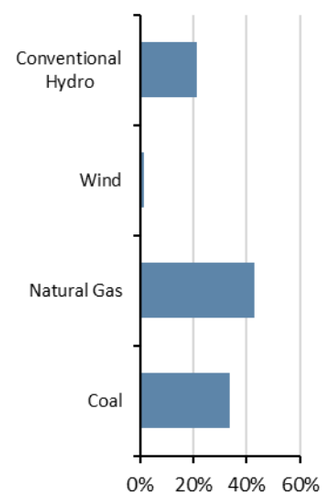
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios. Above-normal summer peak load and outage conditions similar to those observed in Summer 2023 are likely to result in the need to employ operating mitigations (e.g., DR and transfers) and EEAs.

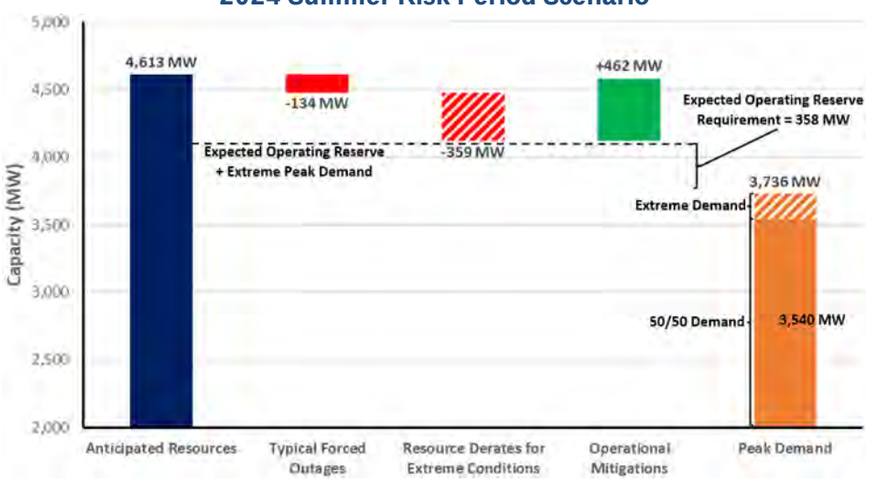
On-Peak Reserve Margin



On-Peak Fuel Mix



2024 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and above-normal scenario based on peak demand with lighting and all consumer loads

Forced Outages: Estimated by using SaskPower forced outage model

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: Estimated non-firm imports and standby generators on 2–7-day notice



MRO-SPP

SPP PC's footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP long-term assessment is reported based on the PC footprint, which touches parts of the MRO Regional Entity and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million.

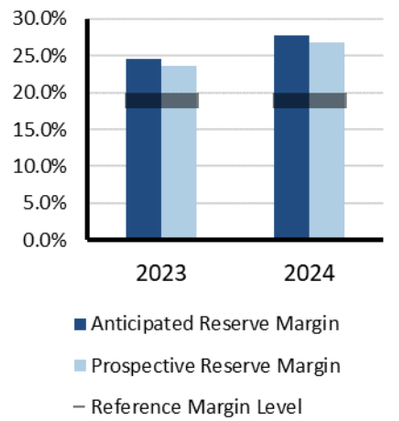
Highlights

- ARMs are higher in SPP compared to Summer 2023. Increased capacity for the summer is coming from wind resource additions, higher expected wind contribution at peak demand, and commitments from switchable generators (i.e., resources capable of supplying SPP or a neighboring BA) to qualify as resources in SPP.
- SPP projects a low likelihood of any emerging reliability issues impacting the area for the 2024 summer season.
- BA generation capacity deficiency risks remain depending on wind generation output levels and unanticipated generation outages in combination with high-load periods.
- Using the current operational processes and procedures, SPP will continue to assess the needs for the 2024 summer season and will adjust as needed to ensure that real-time reliability is maintained throughout the summer time frame.

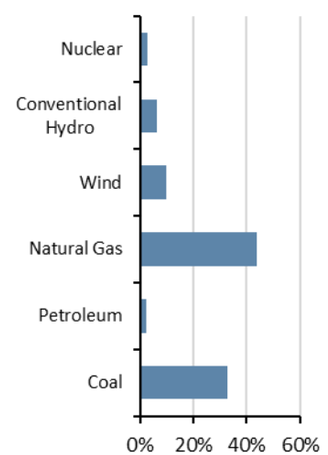
Risk Scenario Summary

Expected resources are sufficient to meet operating reserve requirements under normal peak-demand and outage scenarios. Above-normal summer peak load and outage conditions could necessitate operating mitigations (e.g., DR and transfers from neighboring systems) and EEAs.

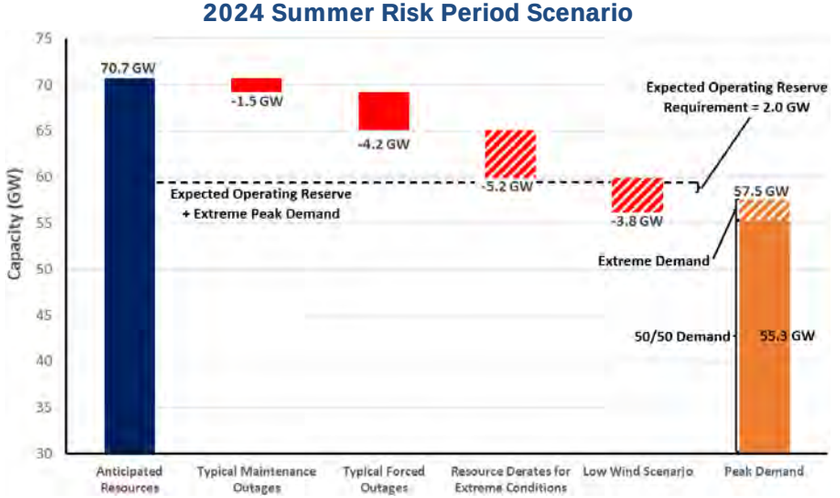
On-Peak Reserve Margin



On-Peak Fuel Mix



2024 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand is a 5% increase from net internal demand

Maintenance and Forced Outages: Represent five-year historical averages; calculated from SPP's generation assessment process

Extreme Derates: Additional unavailable capacity from operational data at high-demand periods

Low Wind Scenario: Derates reflecting a low-wind day in the summer



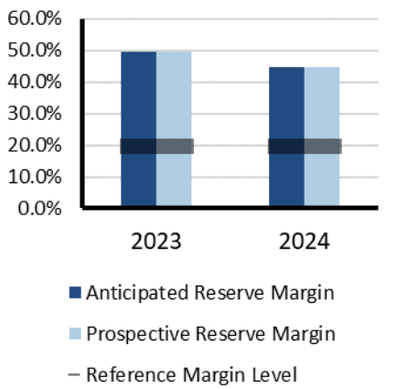
NPCC-Maritimes

The Maritimes assessment area is a winter-peaking NPCC area that contains two BAs. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, and Prince Edward Island and the northern portion of Maine, which is radially connected to the New Brunswick power system. The area covers 58,000 square miles with a total population of 1.9 million.

Highlights

- The Maritimes area has not identified any operational issues that are expected to impact system reliability. If an event were to occur, emergency operations and planning procedures are in place.
- All of the area's declared firm capacity is expected to be operational for the summer operating period.
- As part of the planning process, dual-fueled units will have sufficient supplies of heavy fuel oil (HFO) on site to enable sustained operation in the event of natural gas supply interruptions.

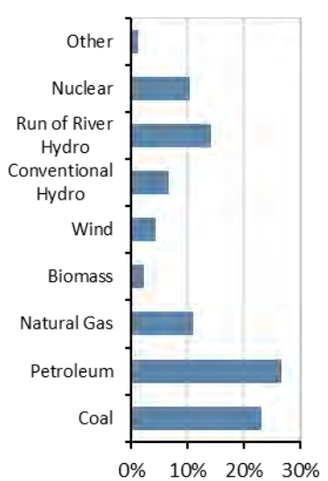
On-Peak Reserve Margin



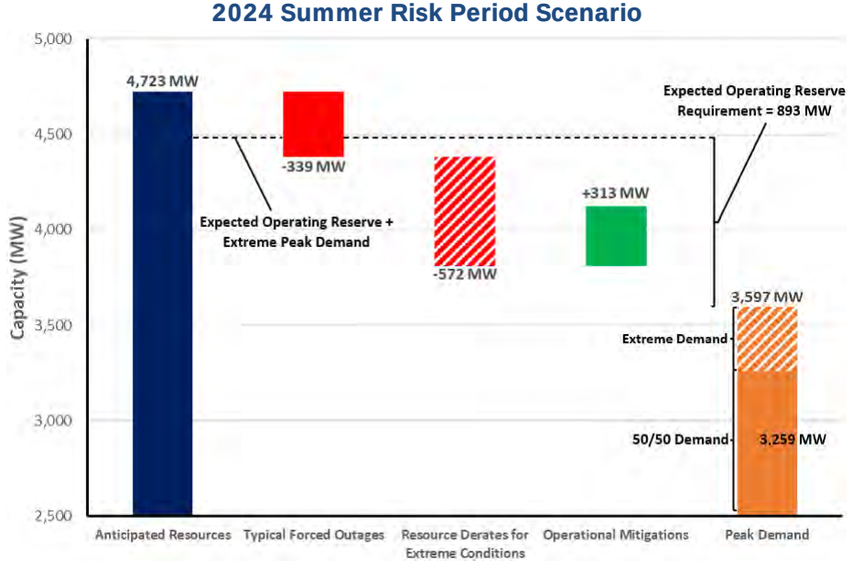
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load or extreme outage conditions could necessitate operating mitigations (e.g., DR and non-firm transfers) and EEAs.

On-Peak Fuel Mix



2024 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (above 90/10) extreme demand forecast

Forced Outages: Based on historical operating experience

Extreme Derates: A low-likelihood scenario resulting in an additional 50% derate in the remaining capacity of both natural gas and wind resources under extreme conditions

Operational Mitigations: Imports anticipated from neighbors during emergencies



NPCC-New England

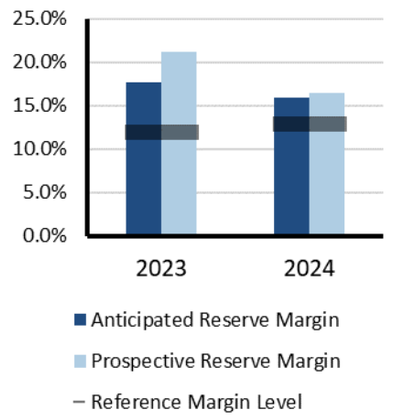
NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont that is served by ISO New England (ISO-NE) Inc. ISO-NE is a regional transmission organization that is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administration of the area's wholesale electricity markets, and management of the comprehensive planning of the regional BPS.

The New England BPS serves approximately 14.5 million customers over 68,000 square miles.

Highlights

- The New England area expects to have sufficient resources to meet the 2024 summer peak demand forecast.
- 330 MW of resources are currently on emergency outage but are scheduled to be available during the summer operating period.
- The 50/50 peak summer demand is forecast to be 24,633 MW for the weeks beginning June 2, 2024, through September 15, 2024, with a lowest projected net margin of -401 MW (-1.6%). This margin assumes a net interchange of 1,297 MW, which is capacity backed. However, ISO-NE typically imports around 3,000 MW during summer peak load conditions. For this *SRA*, the established Reference Margin Level is 12.9%. Wind, grid-connected solar PV, and run-of-river totals were derated for this calculation.
- The 2024 summer demand forecast factors in demand reductions associated with energy efficiency, load management, behind-the-meter photovoltaic (BTM-PV) systems, and distributed generation.

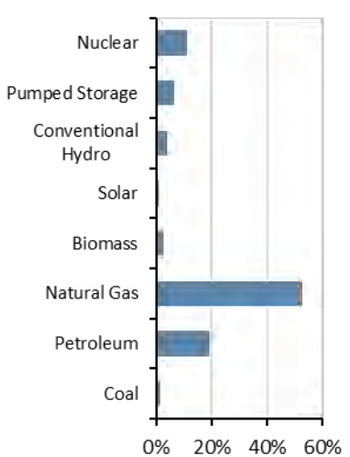
On-Peak Reserve Margin



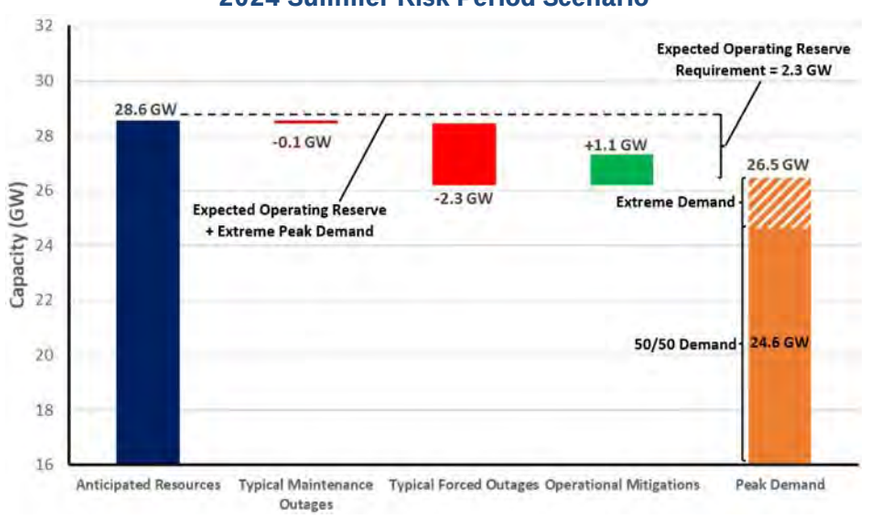
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under normal peak-demand and outage scenarios. Operating mitigations (e.g., DR and transfers) are likely to be needed to meet peak demand. More severe conditions (e.g., above-normal summer peak load and outage conditions) could result in an EEA.

On-Peak Fuel Mix



2024 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Peak net internal demand (50/50) and (90/10) extreme demand forecast

Maintenance Outages: Based on historical weekly averages

Typical Forced Outages: Based on seasonal capacity of each resource as determined by ISO-NE

Operational Mitigations: Based on load and capacity relief assumed available from invocation of ISO-NE operating procedures



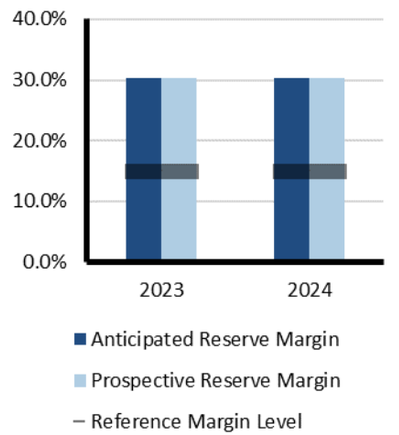
NPCC-New York

NPCC-New York is an assessment area consisting of the NYISO service territory. NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. NYISO is the only BA within the state of New York. The BPS in New York encompasses over 11,000 miles of transmission lines and 760 power generation units and serves 20.2 million customers. For this *SRA*, the established RML is 15%. Wind, grid-connected solar PV, and run-of-river totals were derated for this calculation. However, New York requires load-serving entities to procure capacity for their loads equal to their peak demand plus an IRM. The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council. The council approved the 2024–2025 IRM at 22.0%.

Highlights

- NYISO is not anticipating any operational issues in the New York Control Area for the upcoming summer.
- No unanticipated operating conditions occurred during the summer 2023 season.
- Adequate capacity margins are anticipated, and existing operating procedures are sufficient to handle any issues that may occur.

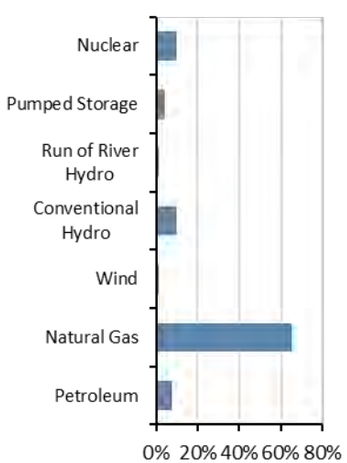
On-Peak Reserve Margin



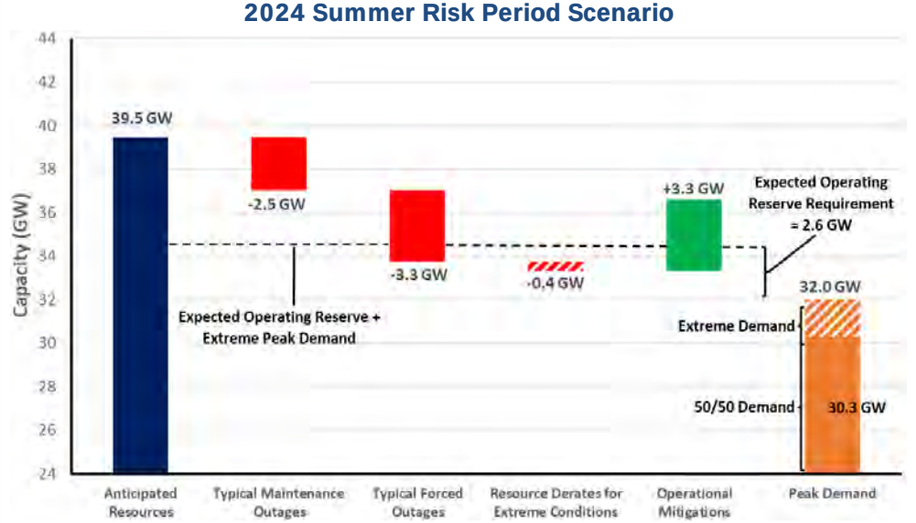
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios. Operating mitigations (e.g., DR and transfers) may be needed to meet above-normal summer peak load and outage conditions.

On-Peak Fuel Mix



2024 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) extreme demand forecast

Maintenance Outages: Based on historical performance and the new NYISO capacity accreditation process

Forced Outages: Based on historical five-year averages

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: A total of 3.3 GW based on operational/emergency procedures in area emergency operations manual



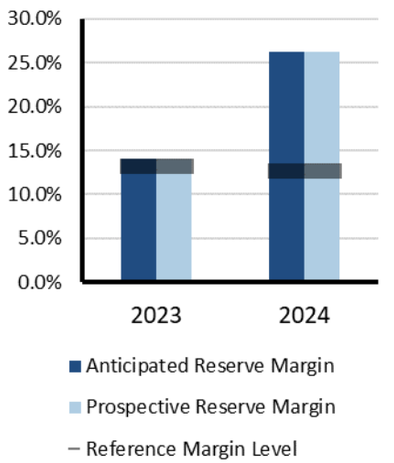
NPCC-Ontario

NPCC-Ontario is an assessment area in the Ontario province of Canada. The IESO is the BA for the province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of more than 15 million. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

Highlights

- Overall, Ontario is operating within a period in which generation and transmission outages are more challenging to accommodate. The IESO has been actively coordinating and planning with market participants to maintain reliability.
- The Ontario grid is better positioned for Summer 2024 than it was for Summer 2023.
- This season, the grid will benefit from fewer coincident planned generator outages, progress being made on nuclear refurbishments, increased capacity secured through the capacity auction, and new demand-side management programs, including the Interruptible Rate Pilot and Peak Perks.
- The system will be adequate in Summer 2024 under normal weather conditions. It is also expected to be adequate during extreme weather conditions with the availability of up to 2,000 MW of imports from neighboring jurisdictions or other operating actions to ensure reliability.

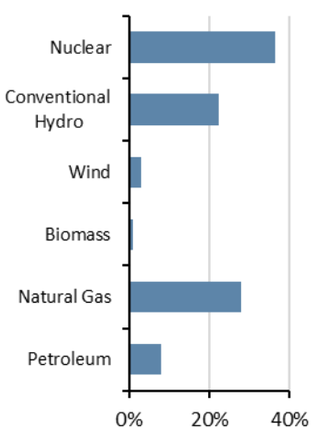
On-Peak Reserve Margin



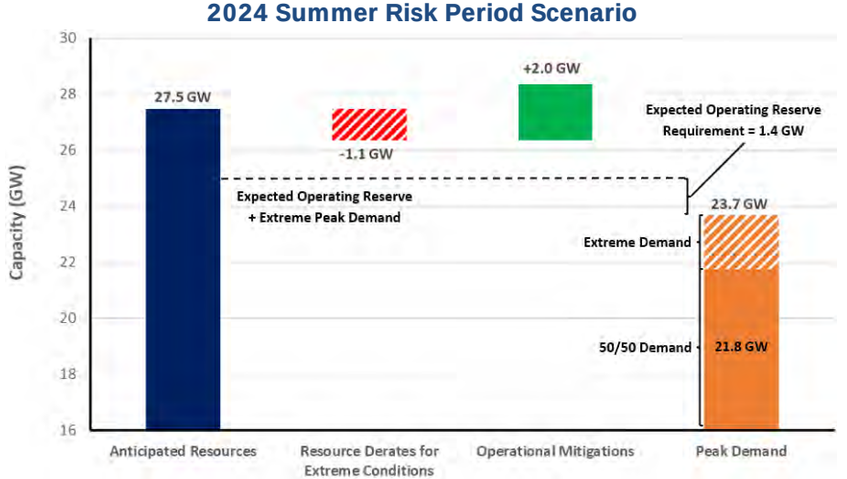
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2024 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50 forecast) and highest weather-adjusted daily demand based on 31 years of demand history

Extreme Derates: Derived from weather-adjusted temperature rating of thermal units and adjustments to expected hydro production for low water conditions

Operational Mitigations: Imports anticipated from neighbors during emergencies



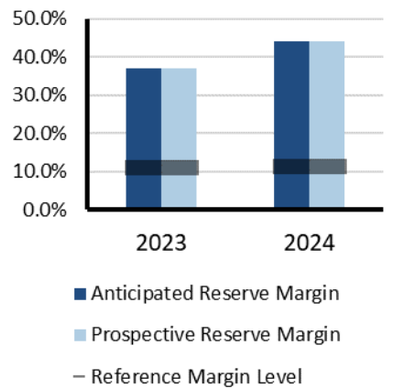
NPCC-Québec

The Québec assessment area (province of Québec) is a winter-peaking NPCC area that covers 595,391 square miles with a population of 8 million. Québec is one of the four Interconnections in North America; it has ties to Ontario, New York, New England, and the Maritimes consisting of either high-voltage direct current ties, radial generation, or load to and from neighboring systems.

Highlights

- The Québec area forecasted summer peak demand (excluding April, May, and September) is 22,922 MW during the week beginning August 11, 2024, with a forecasted net margin of 7,423 MW (32.4%).
- Resource adequacy issues are not expected this summer.
- The Québec area expects to be able to assist other areas, if needed, up to the transfer capability available.

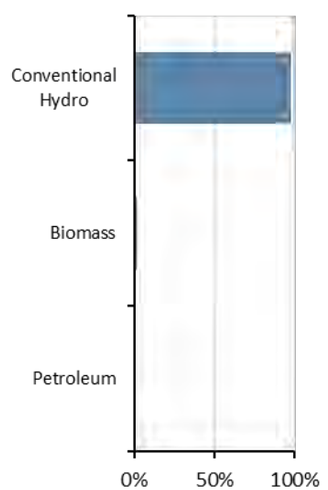
On-Peak Reserve Margin



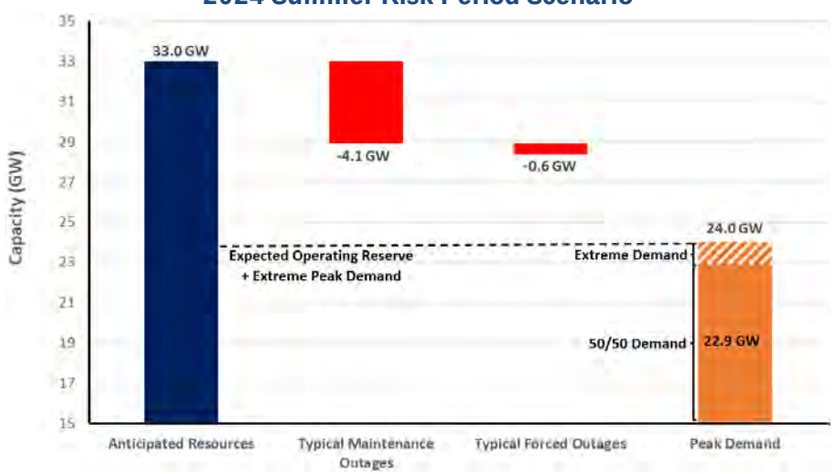
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2024 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenario: Net internal demand (50/50) and (90/10) demand forecast

Net Firm Transfers: Anticipated exports to neighbors during the risk hour



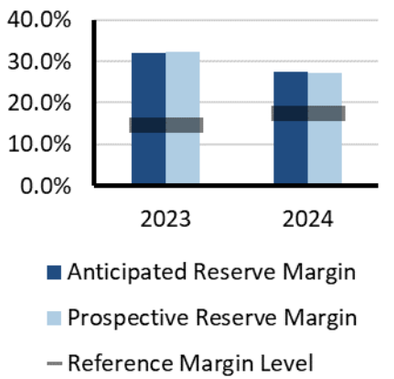
PJM

PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM serves 65 million customers and covers 369,089 square miles. PJM is a BA, PC, Transmission Planner, Resource Planner, Interchange Authority, TOP, Transmission Service Provider, and RC.

Highlights

- PJM expects no resource problems over the 2024 summer peak season. PJM is forecasting around 29% installed reserves (including expected committed DR), which is well above the target IRM of 17.7%. The increase of 1.8 percentage points of the reserve requirement is driven by adjusted load forecast parameters.
- Rising demand, generator retirements, and slower-than-anticipated resource additions contribute to lower reserve margins compared to last summer.
- The greatest load-loss risk remains the hour with highest forecasted demand due to the low penetration of variable energy resources relative to PJM's peak load.

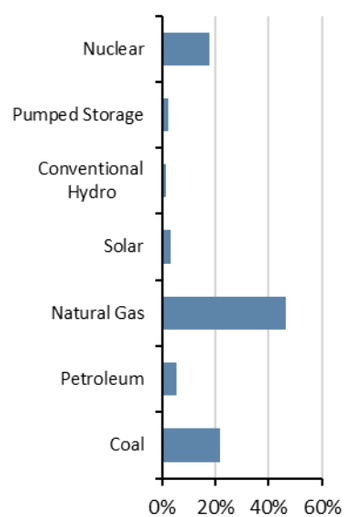
On-Peak Reserve Margin



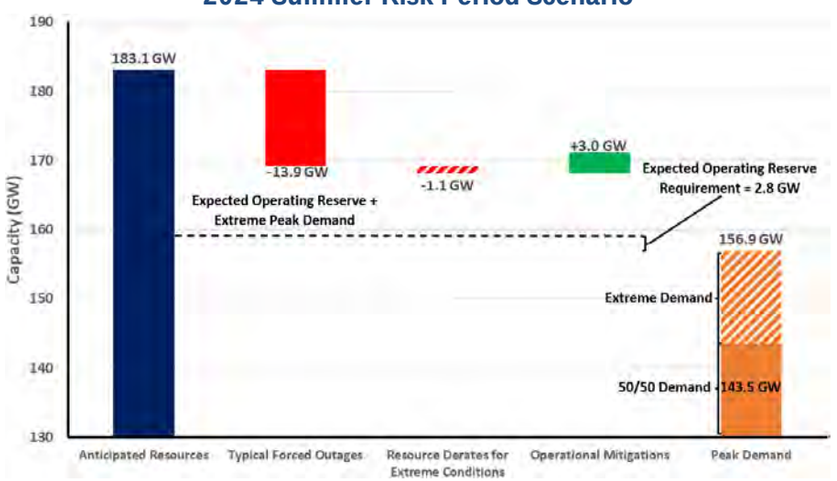
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2024 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Based on historical data and trending

Extreme Derates: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 3 GW based on operational/emergency procedures



SERC-Central

SERC-Central is an assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. Historically a summer-peaking area, SERC-Central is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission (FERC)-approved delegation agreements with NERC. SERC-Central is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

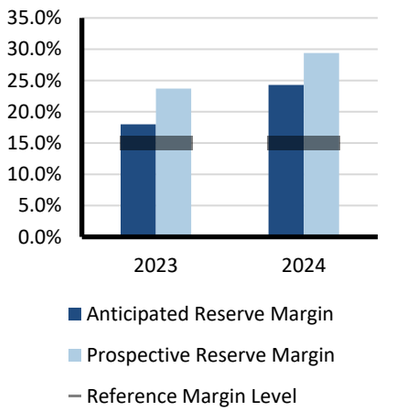
Highlights

- SERC-Central will have higher reserves compared to last summer due to increased firm imports and additions of gas and solar generation.
- Expected resources meet operating reserve requirements under the assessed scenarios.
- The probabilistic analysis metrics indicate adequate energy resources for the subregion.
- Entities perform resource studies to ensure resource adequacy to meet the summer peak demand and maintain the reliability of the system. They actively participate in the SERC Near-Term, Long-Term, and Resource Adequacy Working Groups, which identify emerging and potential reliability impacts on transmission and resource adequacy along with transfer capability.
- There is a moderate risk of transmission impacts due to severe weather. The advanced age and material condition of older coal- and gas-fired generators could result in potential reliability challenges. Entities are mitigating these risks through summer readiness processes, pursuing short-term market opportunities, and leveraging demand-side management programs as necessary.

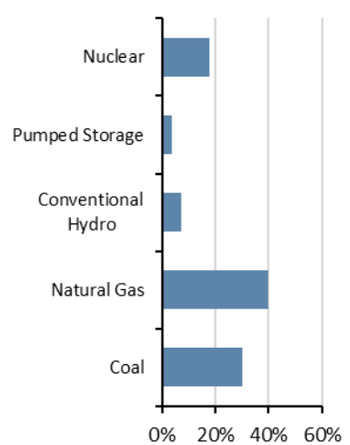
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

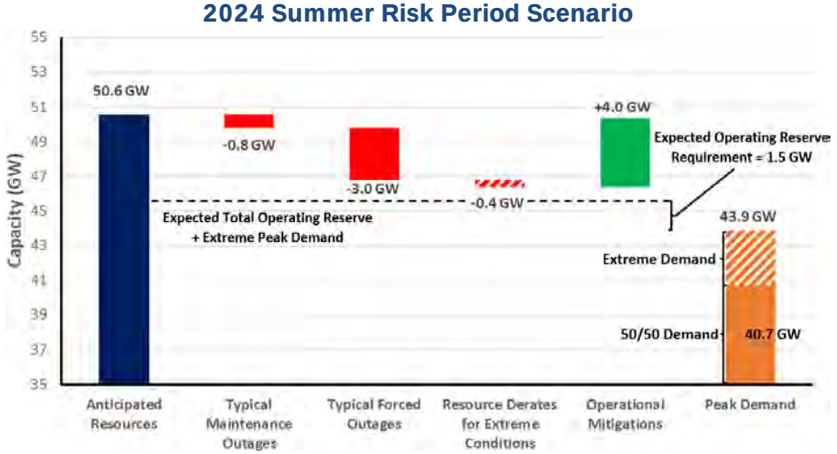
On-Peak Reserve Margin



On-Peak Fuel Mix



2024 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: A total of 1.9 GW based on operational/emergency procedures



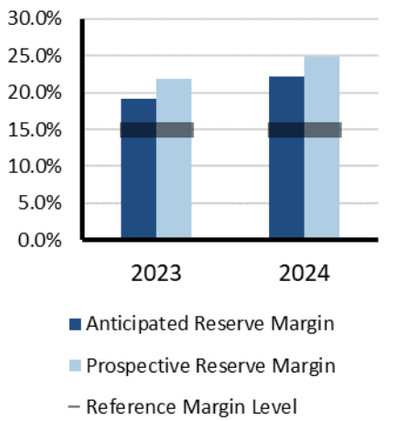
SERC-East

SERC-East is an assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina. Historically a summer-peaking area, SERC-East is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

Highlights

- Expected resources meet operating reserve requirements under the assessed scenarios.
- The probabilistic analysis metrics show some risk for energy resource adequacy during the summer months of July and August in the afternoon hours.
- Entities perform resource studies to ensure resource adequacy to meet the summer peak demand and maintain the reliability of the system. They actively participate in the SERC Near-Term, Long-Term, and Resource Adequacy Working Groups, which identify emerging and potential reliability impacts on transmission and resource adequacy along with transfer capability.
- Entities have not identified any emerging reliability issues or operational concerns for the upcoming summer season.

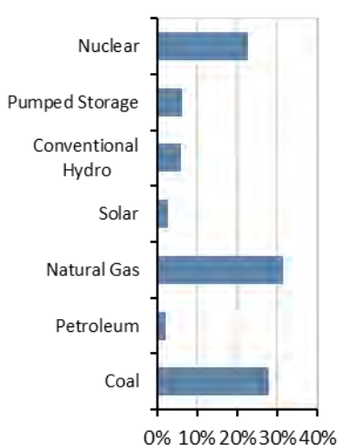
On-Peak Reserve Margin



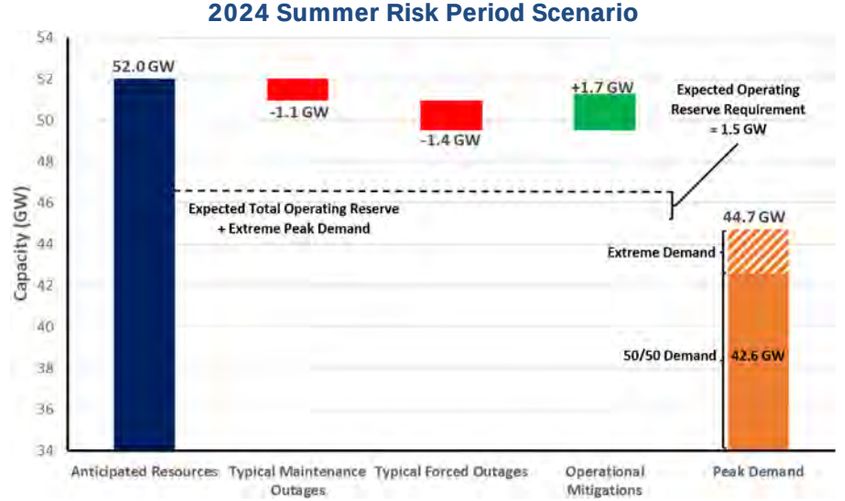
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2024 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 1.5 GW based on operational/emergency procedures



SERC-Florida Peninsula

SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

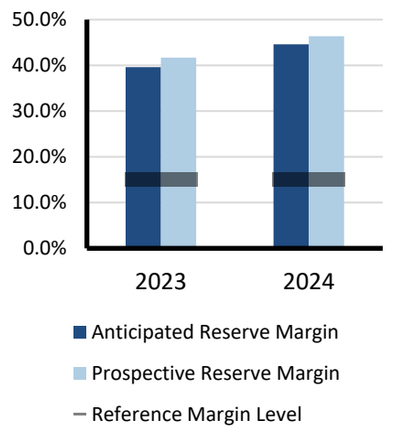
Highlights

- Expected resources meet operating reserve requirements under the assessed scenarios.
- The probabilistic analysis metrics indicate adequate energy resources for the subregion.
- Entities perform resource studies to ensure resource adequacy to meet the summer peak demand and maintain the reliability of the system. They actively participate in the SERC Near-Term, Long-Term, and Resource Adequacy Working Groups, which identify emerging and potential reliability impacts on transmission and resource adequacy along with transfer capability.
- Entities have not identified any emerging reliability issues or operational concerns for the upcoming summer season.

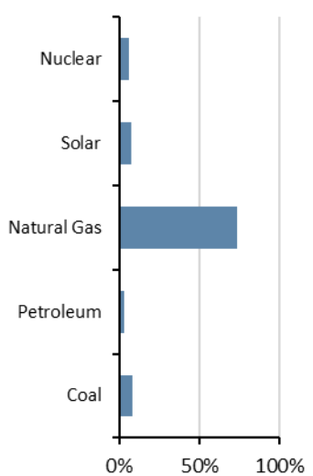
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

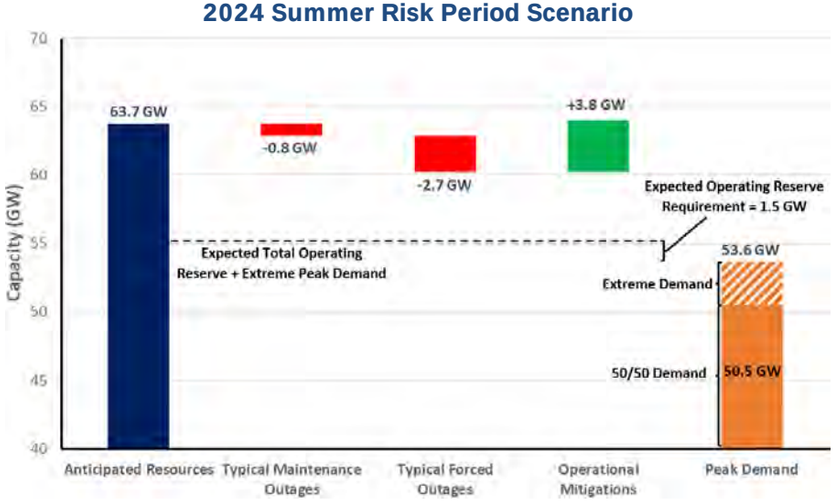
On-Peak Reserve Margin



On-Peak Fuel Mix



2024 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 3.8 GW based on operational/emergency procedures



SERC-Southeast

SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

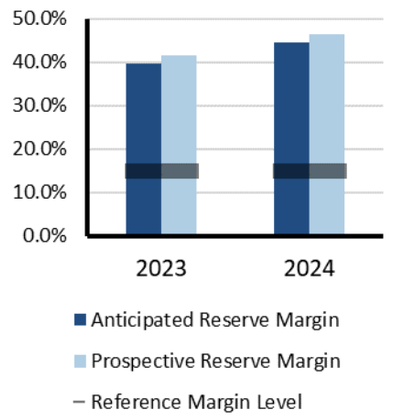
Highlights

- Expected resources meet operating reserve requirements under the assessed scenarios.
- A new 1,100 MW nuclear unit and additional solar generation will give SERC-Southeast higher reserves compared to last summer.
- The probabilistic analysis metrics indicate adequate energy resources for the subregion.
- With the increased penetration of variable energy resources (VER), the curtailment of VER during light-load conditions to support operations may become more prevalent. This, in combination with the retirement of resources, increases the operational challenges in managing the ramps in some areas of SERC-Southeast.
- Entities perform resource studies to ensure resource adequacy to meet the summer peak demand and maintain the reliability of the system. They actively participate in the SERC Near-Term, Long-Term, and Resource Adequacy Working Groups, which identify emerging and potential reliability impacts on transmission and resource adequacy along with transfer capability.

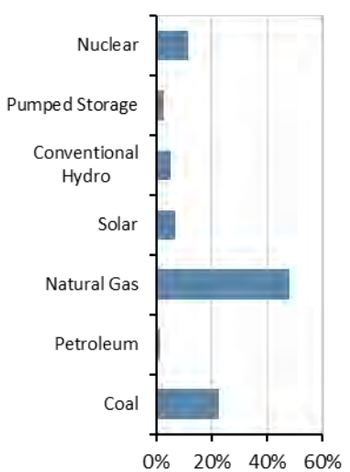
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

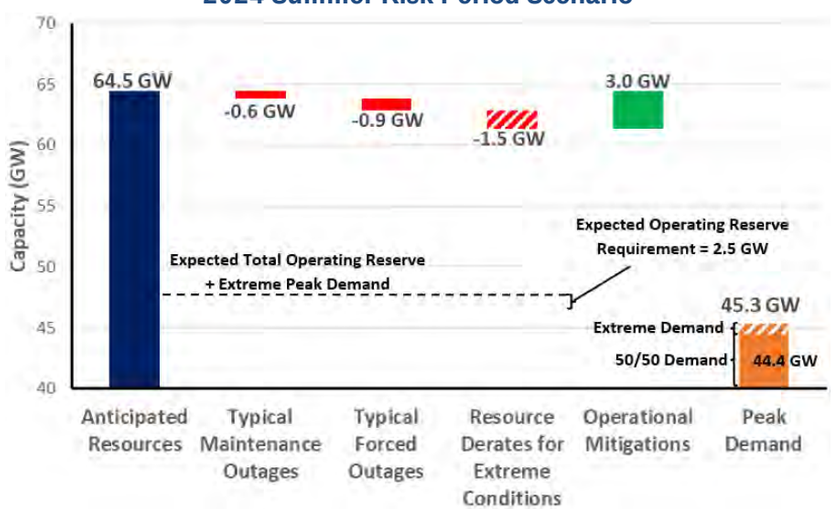
On-Peak Reserve Margin



On-Peak Fuel Mix



2024 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: A total of 3 GW based on operational/emergency procedures



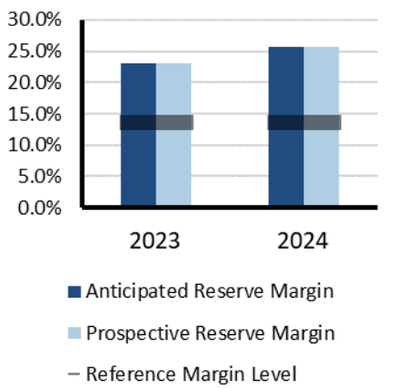
Texas RE-ERCOT

The Electric Reliability Council of Texas (ERCOT) is the independent system operator (ISO) for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT is summer-peaking, and the forecasted summer peak load month is August. It covers approximately 200,000 square miles, connects over 52,700 miles of transmission lines, has over 1,100 generation units, and serves more than 26 million customers. Texas RE is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT. On November 3, 2022, the Public Utility Commission of Texas issued an order directing ERCOT to assume the duties and responsibilities of the reliability monitor for the Texas grid.

Highlights

- Given an ARM of 25.6% and Reference Reserve Margin of 13.75%, ERCOT expects to have sufficient operating reserves for the August peak load hour given expected normal summer system conditions.
- Solar and battery energy storage installed capacity has grown by about 4,500 and 1,600 MW, respectively, since last August.
- Continued robust growth in both loads and intermittent renewable resources has elevated the risk of emergency conditions in the evening hours when solar generation begins to ramp down.
- ERCOT's probabilistic risk assessment indicates an elevated risk of having to declare EEAs during hours ending 8:00–9:00 p.m. Central on the August peak load day. ERCOT judges an hour to have elevated risk (as opposed to low risk) when the probability of an EEA is greater than 10%. The EEA probability for these two hours is about 16% and 18%, respectively.
- Contributing to the elevated risk is a potential need, under certain grid conditions, to limit power transfers from South Texas into the San Antonio region. Conditions could cause overloads on the lines that make up the South Texas export and import interfaces, necessitating South Texas generation curtailments and potential firm load shedding to avoid cascading outages. The risk is greatest when ERCOT has extremely high net loads in the early evening hours. This issue will be addressed with mitigation measures including the construction of the San Antonio South Reliability Project, which is anticipated to be completed by Summer 2027.

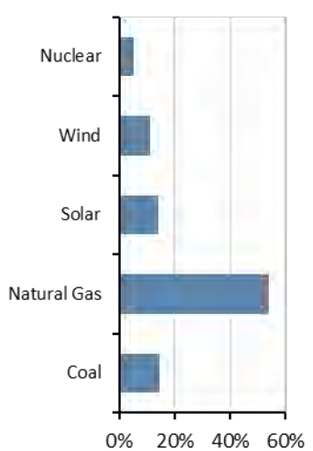
On-Peak Reserve Margin



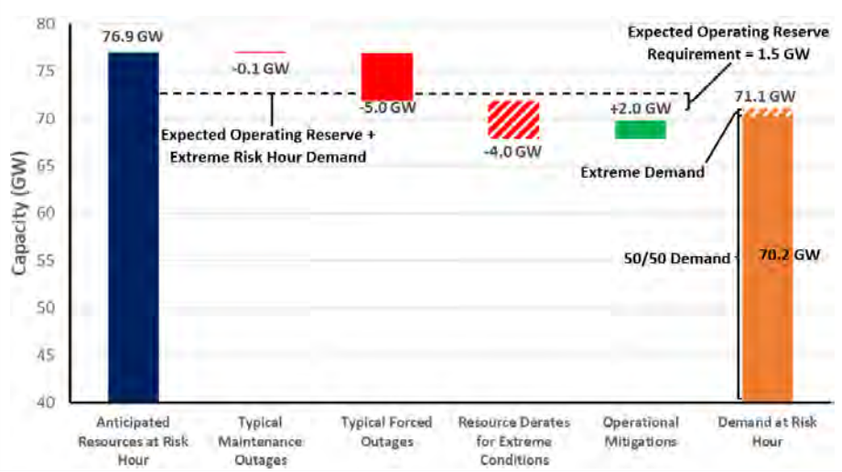
Risk Scenario Summary

Expected resources meet operating reserve requirements for the peak demand hour scenario. However, there is risk of supply shortages as solar generation ramps down during the early evening hours when system load is high and transmission constraints limit transfers.

On-Peak Fuel Mix



2024 Summer Risk Period Scenario (9:00 p.m. local time)



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at hour ending 9 p.m. local time as solar PV output is diminished and demand remains high

Demand Scenarios: Net internal demand (50/50) and extreme demand (95/5) based on August peak load

Forced Outages: Based on the 95th percentile of historical averages of forced outages for June through September weekdays, hours ending 3:00–8:00 p.m. local time for the last three summer seasons

Extreme Derates: Based on the 90th percentile of thermal forced outages for peak August load day

Low Wind Scenario: Based on the 10th percentile of historical averages of hourly wind for June through September, hours ending 1:00–9:00 p.m. local time

Operational Mitigations: Additional capacity from switchable generation and additional imports



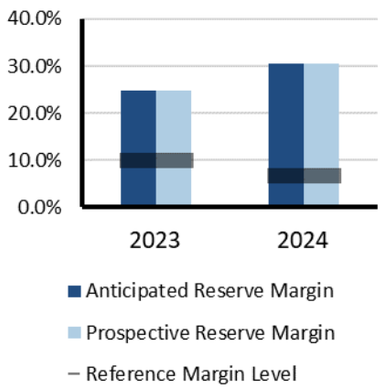
WECC-AB

WECC-AB (Alberta) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of Alberta. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada and the northern portion of Baja California in Mexico as well as all or portions of the 14 western U.S. states in between.

Highlights

- Thermal and renewable capacity are being added to the area to address rapid load growth, but supply chain issues causing project delays or cancellations may be an issue.
- Thermal tier 1 resources for this upcoming summer include a new 900 MW natural gas combined-cycle facility and the conversion of two existing coal units to two 1x1 natural gas combustion turbine sites with 932 MW (112 incremental MW) of capacity after the steam turbine tie in. The two coal sites undergoing conversion to natural gas are the only remaining coal facilities operating in the area.
- Issues maintaining rate of change of frequency (ROCOF) during islanded or near-islanded situations with high IBR output and low demand is also a concern.
- Alberta is expected to have sufficient resource availability to meet reserves at the peak demand hour (4:00–5:00 p.m.). This evaluation considers a 1-in-10 probability (90th percentile) level for peak demand and a combination of resource derates.
- Alberta shows no LOLH or EUE for the upcoming summer season.

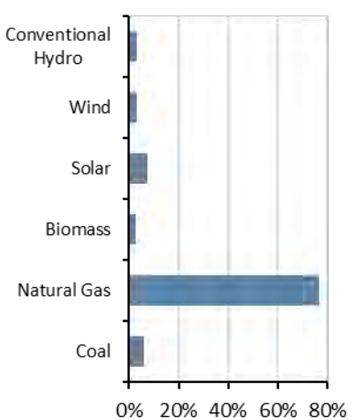
On-Peak Reserve Margin



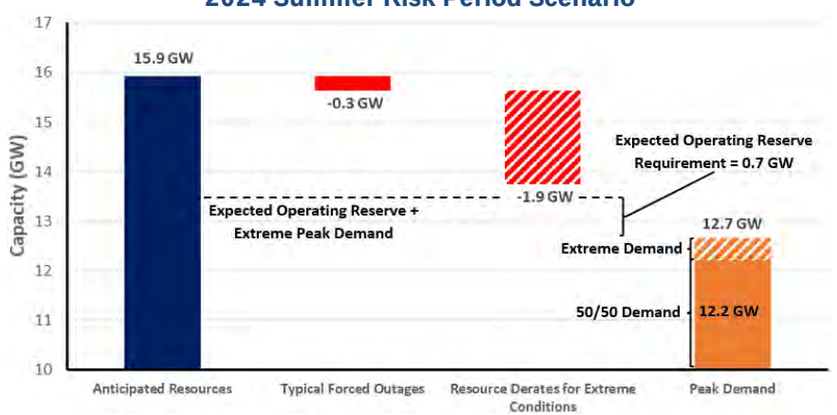
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2024 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Typical Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) point of resource performance distribution



WECC-BC

WECC-British Columbia (BC) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of British Columbia. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada and the northern portion of Baja California in Mexico as well as all or portions of the 14 western U.S. states in between.

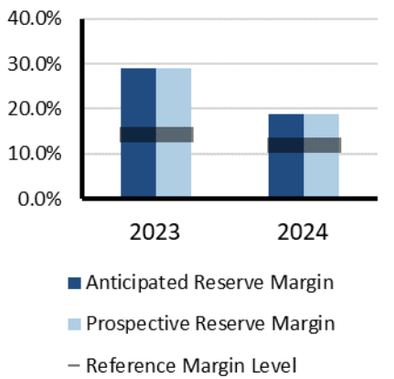
Highlights

- British Columbia faces operational challenges on multiple fronts, including drought, wildfires, and rapid electrification in the residential, commercial, industrial, and transportation sectors.
- British Columbia is expected to have sufficient resource availability to meet reserves at the peak demand hour (5:00–6:00 p.m.) under most conditions. However, above-normal demand that coincides with low hydro output could result in a reserve shortage. This evaluation considers a 1-in-10 probability (90th percentile) level for peak demand and a combination of resource derates including low hydro output.
- WECC's probabilistic analysis shows no LOLH or EUE for British Columbia during the upcoming summer season.

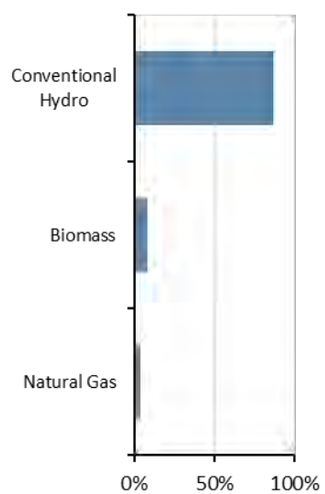
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (e.g., DR and transfers) and EEAs.

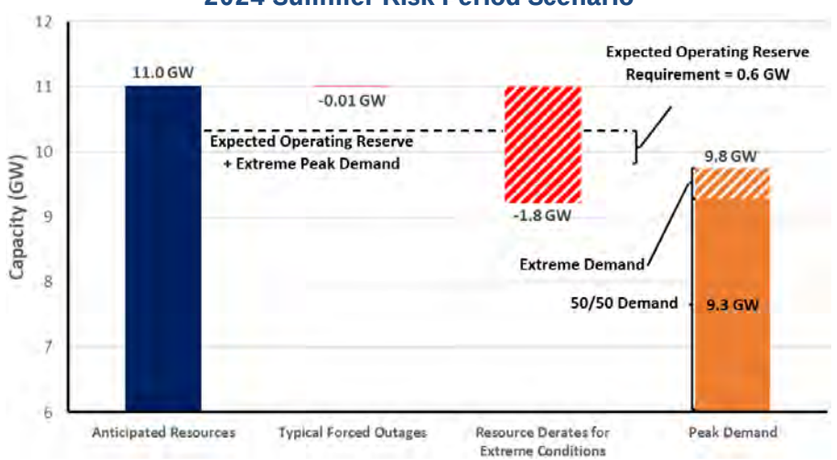
On-Peak Reserve Margin



On-Peak Fuel Mix



2024 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) resource performance distribution at peak hour



WECC-CA/MX

WECC-CA/MX is a summer-peaking assessment area in the WECC Regional Entity that includes parts of California, Nevada, and Baja California, Mexico. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada and the northern portion of Baja California in Mexico as well as all or portions of the 14 western U.S. states in between.

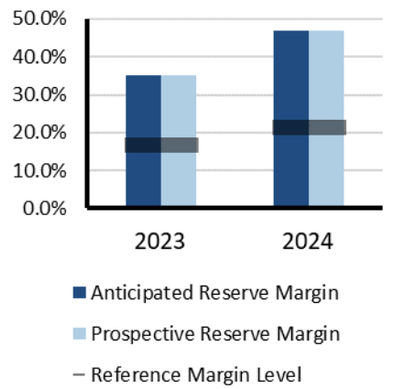
Highlights

- Drought conditions, which were a concern prior to 2023, have been alleviated for the upcoming summer.
- CA/MX is expected to have sufficient resource availability to meet reserves at the peak demand hour (4:00–5:00 p.m.). The riskiest hour for CA/MX is the hour ending 6:00–7:00 p.m. when solar output is low, causing the area to rely on imports to meet demand.
- In WECC's probabilistic analysis, CA/MX is projected to have LOLH ranging from negligible to 0.8 hours with the greatest risk of EUE and LOLH being in the Baja (Mexico) part of CA/MX. Variation in LOLH in the analysis is attributable to the amount of Tier 1 resource additions that connect before the later months. Supply chain issues resulting in the delay or cancellation of Tier 1 projects are a potential risk this summer for CA/MX.
- WECC's analysis considers a 1-in-10 probability (90th percentile) level for peak demand and a combination of resource derates.

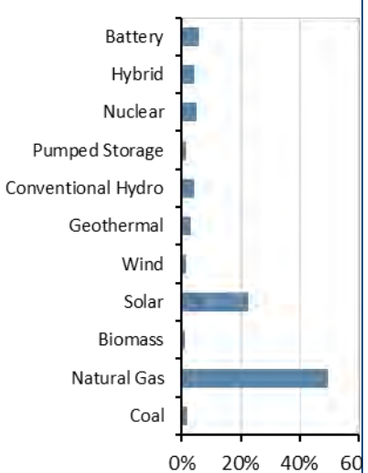
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could necessitate operating mitigations (e.g., DR and transfers) and EEAs.

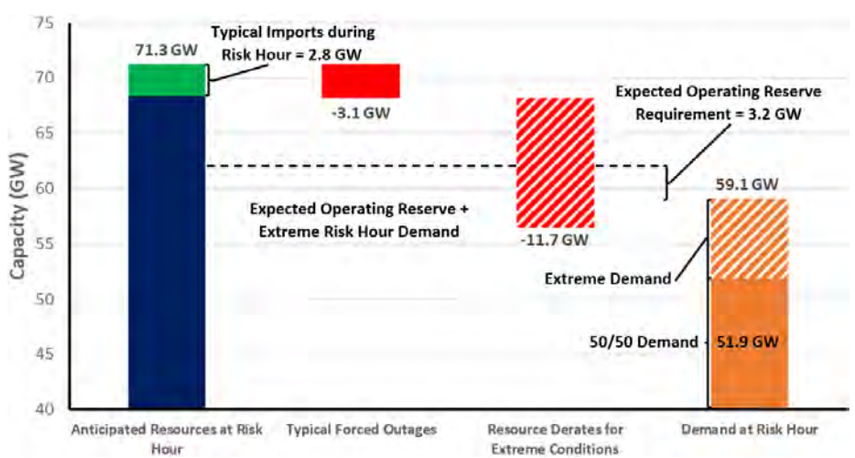
On-Peak Reserve Margin



On-Peak Fuel Mix



2024 Summer Risk Period Scenario (7 p.m. local time)



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at hour ending 7:00 p.m. local time as solar PV output is diminished and demand remains high

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Estimated using market forced outage model

Extreme Derates: On natural gas units based on historical data and manufacturer data for temperature performance and outages



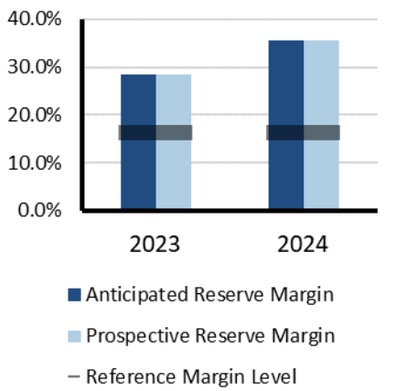
WECC-NW

WECC-NW is a summer-peaking assessment area in the WECC Regional Entity. The area includes Colorado, Idaho, Montana, Oregon, Utah, Washington, and Wyoming and parts of California, Nebraska, Nevada, and South Dakota. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada and the northern portion of Baja California in Mexico as well as all or portions of the 14 western U.S. states in between.

Highlights

- Operational challenges for the Northwest include supply chain issues potentially resulting in project delays or cancellations and unprecedented flow patterns associated with the expansion of IBRs.
- The Northwest is expected to have sufficient resource availability to meet reserves at the peak demand hour (4:00–5:00 p.m.). This evaluation considers a 1-in-10 probability (90th percentile) level for peak demand and a combination of resource derates.
- The Northwest shows no LOLH or EUE for the upcoming summer season.

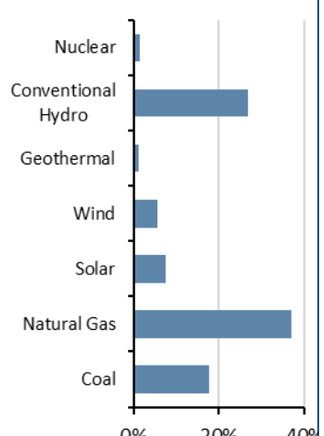
On-Peak Reserve Margin



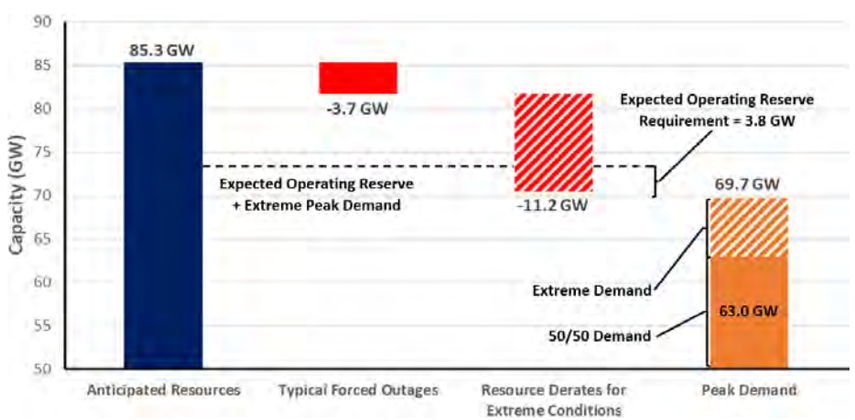
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (e.g., DR and transfers) and EEAs.

On-Peak Fuel Mix



2024 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario



WECC-SW

WECC-SW is a summer-peaking assessment area in the WECC Regional Entity. It includes Arizona, New Mexico, and parts of California and Texas. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada as well as the northern portion of Baja California in Mexico and all or portions of the 14 western U.S. states in between.

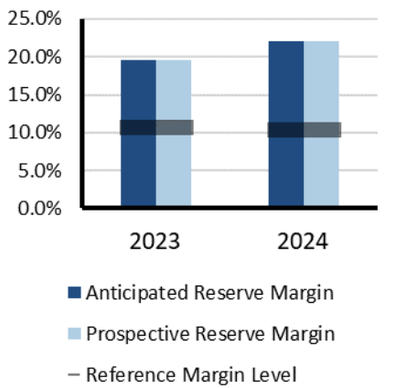
Highlights

- Operational challenges for the Southwest include drought, wildfires, derates of gas facilities due to extreme heat, and supply chain issues potentially affecting thermal resource return to service dates and CODs.
- The Southwest is expected to have sufficient resource availability to meet reserves at the peak demand hour (4:00–5:00 p.m.) under most conditions. However, above-normal demand that coincides with high generator forced outages or other low-resource conditions could result in a reserve shortage. This evaluation considers a 1-in-10 probability (90th percentile) level for peak demand and a combination of resource derates.
- The Southwest shows no LOLH or EUE for the upcoming summer season in WECC's probabilistic analysis.

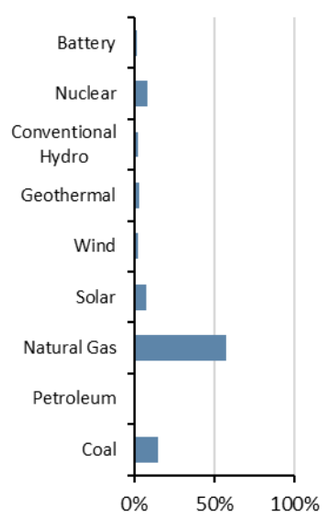
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (e.g., DR and transfers) and EEAs.

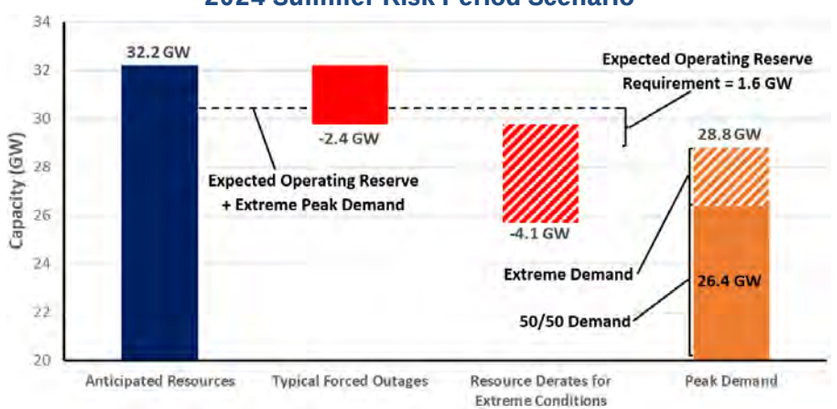
On-Peak Reserve Margin



On-Peak Fuel Mix



2024 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand (5:00 p.m. local)

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Data Concepts and Assumptions

The table below explains data concepts and important assumptions used throughout this assessment.

General Assumptions

- Reliability of the interconnected BPS is comprised of both adequacy and operating reliability:
  - Adequacy is the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
  - Operating reliability is the ability of the electric system to withstand sudden disturbances, such as electric short-circuits or unanticipated loss of system components.
- The reserve margin calculation is an important industry planning metric used to examine future resource adequacy.
- All data in this assessment is based on existing federal, state, and provincial laws and regulations.
- Differences in data collection periods for each assessment area should be considered when comparing demand and capacity data between year-to-year seasonal assessments.
- *2023 Long-Term Reliability Assessment* data has been used for most of this 2024 summer assessment period augmented by updated load and capacity data.
- A positive net transfer capability would indicate a net importing assessment area; a negative value would indicate a net exporter.

Demand Assumptions

- Electricity demand projections, or load forecasts, are provided by each assessment area.
- Load forecasts include peak hourly load[12] or total internal demand for the summer and winter of each year.[13]
- Total internal demand projections are based on normal weather (50/50 distribution)[14] and are provided on a coincident[15] basis for most assessment areas.
- Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable DR projected to be available during the peak hour.

Resource Assumptions

Resource planning methods vary throughout the North American BPS. NERC uses the categories below to provide a consistent approach for collecting and presenting resource adequacy. Because the electrical output of variable energy resources (e.g., wind, solar PV) depends on weather conditions, their contribution to reserve margins and other on-peak resource adequacy analysis is less than their nameplate capacity.

Anticipated Resources:

- **Existing-Certain Capacity**: Included in this category are commercially operable generating units or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the summer season: unit must have a firm capability and have a power purchase agreement with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or, where energy-only markets exist, unit must be a designated market resource eligible to bid into the market.
- **Tier 1 Capacity Additions**: This category includes capacity that either is under construction or has received approved planning requirements.
- **Net Firm Capacity Transfers (Imports minus Exports)**: This category includes transfers with firm contracts.

[12] *Glossary of Terms* used in NERC Reliability Standards
[13] The summer season represents June–September and the winter season represents December–February.
[14] Essentially, this means that there is a 50% probability that actual demand will be higher and a 50% probability that actual demand will be lower than the value provided for a given season/year.
[15] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval; this is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year. SERC calculates total internal demand on a noncoincidental basis.

Prospective Resources: Includes all anticipated resources plus the following:

Existing-Other Capacity: Included in this category are commercially operable generating units or portions of generating units that could be available to serve load for the period of peak demand for the season but do not meet the requirements of existing-certain.

Reserve Margin Descriptions

Planning Reserve Margin: This is the primary metric used to measure resource adequacy; it is defined as the difference in resources (anticipated or prospective) and net internal demand then divided by net internal demand and shown as a percentage.

Reference Margin Level: The assumptions and naming convention of this metric vary by assessment area. The RML can be determined using both deterministic and probabilistic (based on a 0.1/year loss of load study) approaches. In both cases, this metric is used by system planners to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing an RML is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increase demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, an RML is established by a state, provincial authority, ISO/Regional Transmission Organization (RTO), or other regulatory body. In some cases, the RML is a requirement. RMLs may be different for the summer and winter seasons. If an RML is not provided by an assessment area, NERC applies 15% for predominately thermal systems and 10% for predominately hydro systems.

Seasonal Risk Scenario Chart Description

Each assessment area performed an operational risk analysis that was used to produce the seasonal risk scenario charts in the Regional Assessments Dashboards. The chart presents deterministic scenarios for further analysis of different resource and demand levels: The left **blue** column shows anticipated resources, and the two **orange** columns at the right show the two demand scenarios of the normal peak net internal demand and the extreme summer peak demand—both determined by the assessment area. The middle **red** or **green** bars show adjustments that are applied cumulatively to the anticipated resources, such as the following:

- Reductions for typical generation outages (i.e., maintenance and forced outages that are not already accounted for in anticipated resources)
- Reductions that represent additional outage or performance derating by resource type for extreme, low-probability conditions (e.g., drought condition impacts on hydroelectric generation, low-wind scenario affecting wind generation, fuel supply limitations, or extreme temperature conditions that result in reduced thermal generation output)
- Additional capacity resources that represent quantified capacity from operational procedures, if any, that are made available during scarcity conditions

Not all assessment areas have the same categories of adjustments to anticipated resources. Furthermore, each assessment area determined the adjustments to capacity based on methods or assumptions that are summarized below the chart. Methods and assumptions differ by assessment area and may not be comparable.

The chart enables evaluation of resource levels against levels of expected operating reserve requirement and the forecasted demand. Furthermore, the effects from extreme events can also be examined by comparing resource levels after applying extreme scenario derates and/or extreme summer peak demand.

Resource Adequacy

The ARM, which is based on available resource capacity, is a metric used to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecast peak demand.[16] Large year-to-year changes in anticipated resources or forecast peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. All assessment areas have sufficient ARMs to meet or exceed their RML for the 2024 summer as shown in **Figure 4**.

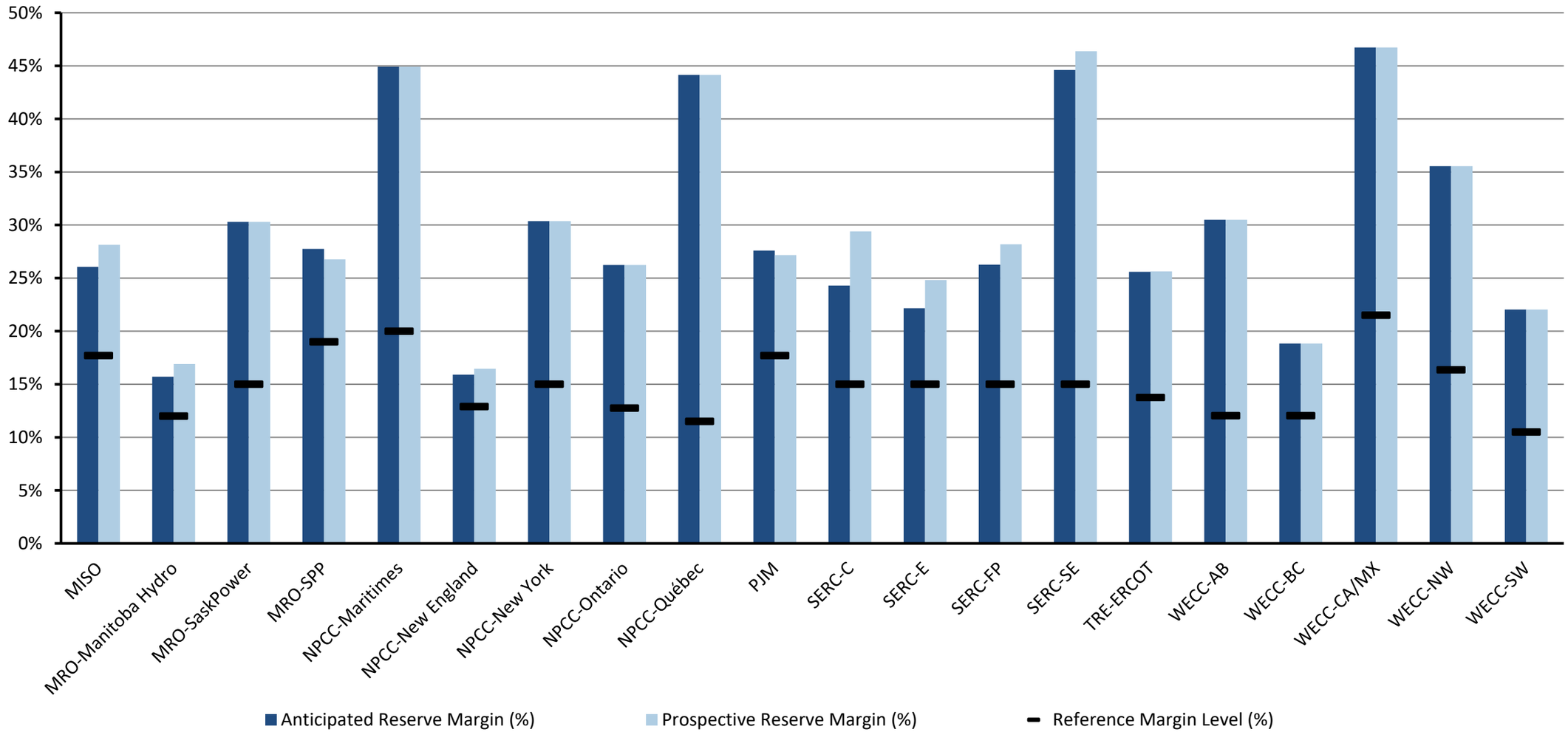
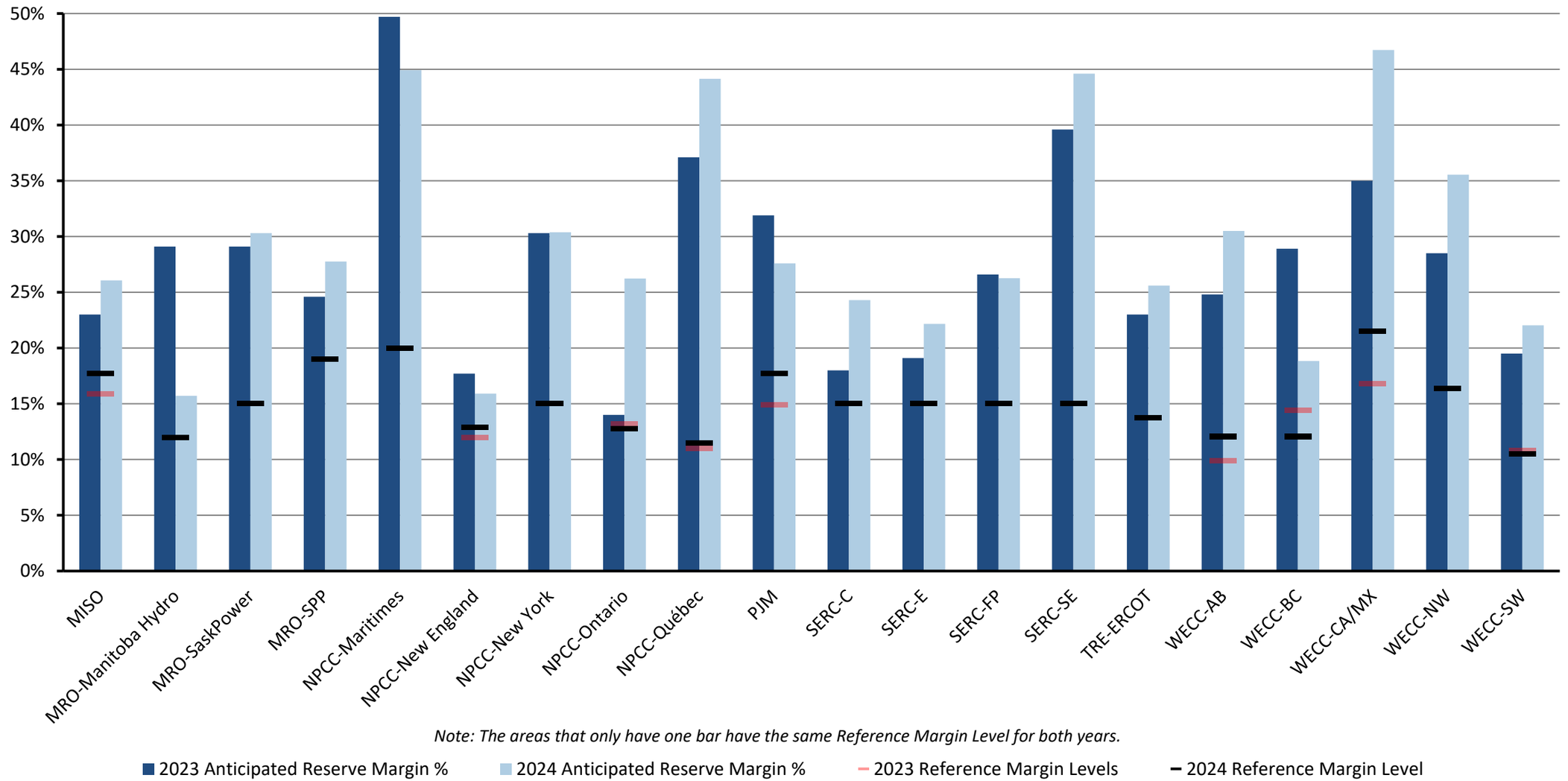


Figure 4: Summer 2024 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[16] Generally, anticipated resources include generators and firm capacity transfers that are expected to be available to serve load during electrical peak loads for the season. Prospective resources are those that could be available but do not meet criteria to be counted as anticipated resources. Refer to the **Data Concepts and Assumptions** section for additional information on Anticipated/Prospective Reserve Margins, anticipated/prospective resources, and RMLs.

Changes from Year-to-Year

Figure 5 provides the relative change in the forecast ARMs from the 2023 summer to the 2024 summer. A significant decline can signal potential operational issues for the upcoming season. Both MRO-Manitoba Hydro and WECC-BC have noticeable reductions in their ARM levels for the 2024 summer. MRO-Manitoba Hydro does not anticipate elevated risk for the upcoming summer, but WECC-BC is experiencing increasing forecasted demand and drought conditions, increasing risk heading into the 2024 summer. Additional details for each assessment area are provided in the **Data Concepts and Assumptions** and **Regional Assessments Dashboards** sections.



Note: The areas that only have one bar have the same Reference Margin Level for both years.

Figure 5: Summer 2023 and Summer 2024 Anticipated Reserve Margins Year-to-Year Change

Net Internal Demand

The changes in forecasted net internal demand for each assessment area are shown in Figure 6.[17] Assessment areas develop these forecasts based on historic load and weather information as well as other long-term projections.

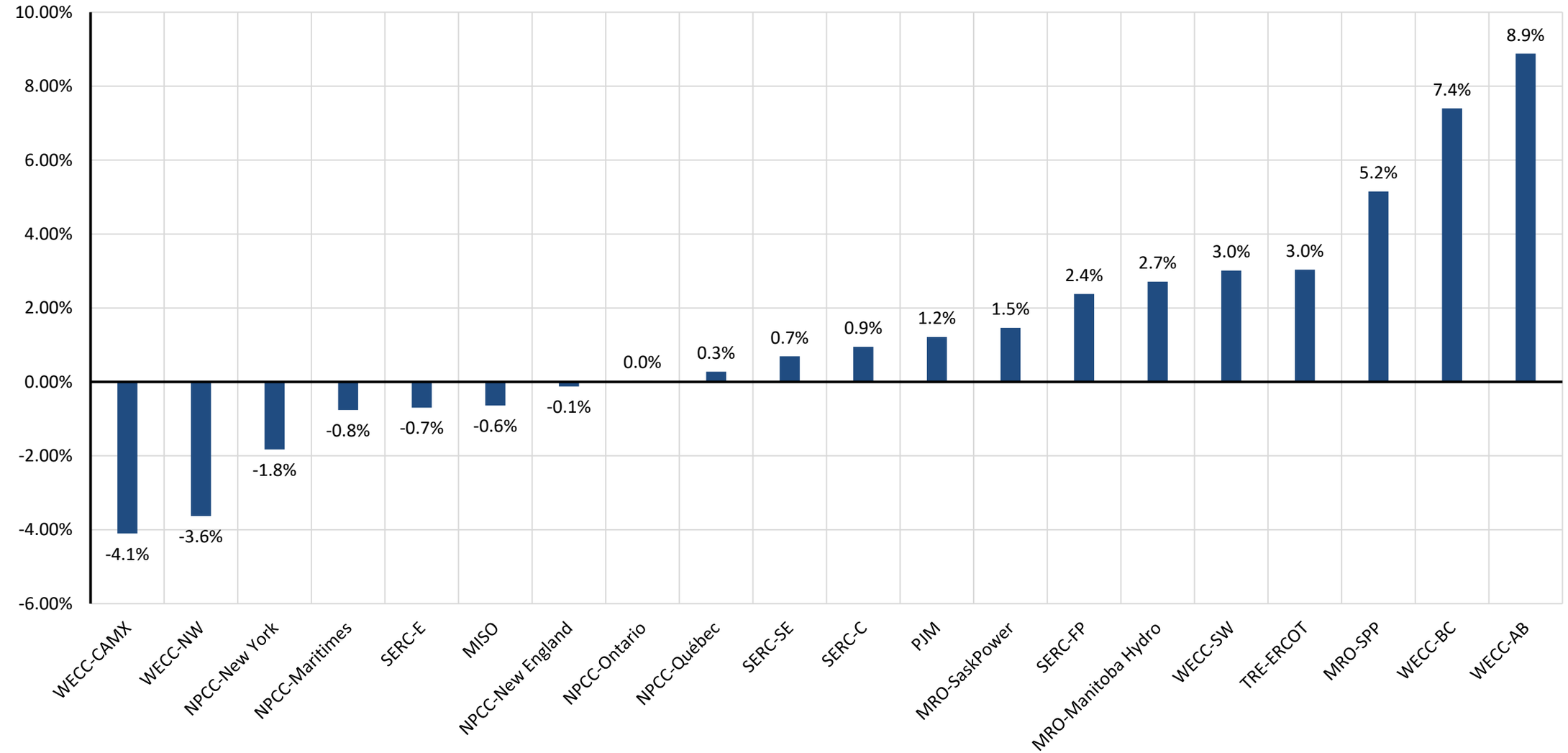


Figure 6: Changes in Net Internal Demand—Summer 2023 Forecast Compared to Summer 2024 Forecast

[17] Changes in modeling and methods may also contribute to year-to-year changes in forecasted net internal demand projections.

Demand and Resource Tables

Peak demand and supply capacity data—resource adequacy data—for each assessment area are as follows in each table (in alphabetical order).

MISO			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	123,728	124,830	0.9%
Demand Response: Available	6,903	8,750	26.8%
Net Internal Demand	116,825	116,079	-0.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	140,650	143,866	2.3%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	3,018	2,471	-18.1%
Anticipated Resources	143,668	146,337	1.9%
Existing-Other Capacity	668	1,833	174.4%
Prospective Resources	151,579	148,740	-1.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	23.0%	26.1%	3.1
Prospective Reserve Margin	29.7%	28.1%	-1.6
Reference Margin Level	15.9%	17.7%	1.8

MRO-SaskPower			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,539	3,590	1.4%
Demand Response: Available	50	50	0.0%
Net Internal Demand	3,489	3,540	1.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,213	4,323	2.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	290	290	0.0%
Anticipated Resources	4,503	4,613	2.4%
Existing-Other Capacity	0	0	-
Prospective Resources	4,503	4,613	2.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	29.1%	30.3%	1.2
Prospective Reserve Margin	29.1%	30.3%	1.2
Reference Margin Level	15.0%	15.0%	0.0

MRO-Manitoba Hydro			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,060	3,143	2.7%
Demand Response: Available	0	0	-
Net Internal Demand	3,060	3,143	2.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,731	5,615	-2.0%
Tier 1 Planned Capacity	91	0	-100.0%
Net Firm Capacity Transfers	-1,872	-1,978	5.7%
Anticipated Resources	3,950	3,637	-7.9%
Existing-Other Capacity	34	37	9.7%
Prospective Resources	3,984	3,674	-7.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	29.1%	15.7%	-13.4
Prospective Reserve Margin	30.2%	16.9%	-13.3
Reference Margin Level	12.0%	12.0%	0.0

MRO-SPP			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	53,468	56,316	5.3%
Demand Response: Available	842	979	16.3%
Net Internal Demand	52,626	55,337	5.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	65,821	70,855	7.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-238	-157	-33.9%
Anticipated Resources	65,583	70,698	7.8%
Existing-Other Capacity	0	0	-
Prospective Resources	65,036	70,151	7.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.6%	27.8%	3.2
Prospective Reserve Margin	23.6%	26.8%	3.2
Reference Margin Level	19.0%	19.0%	0.0

NPCC-Maritimes			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,612	3,586	-0.7%
Demand Response: Available	328	327	-0.3%
Net Internal Demand	3,284	3,259	-0.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,834	4,660	-3.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	81	63	-22.2%
Anticipated Resources	4,915	4,723	-3.9%
Existing-Other Capacity	0	0	-
Prospective Resources	4,915	4,723	-3.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	49.7%	44.9%	-4.8
Prospective Reserve Margin	49.7%	44.9%	-4.8
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New York			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	32,049	31,541	-1.6%
Demand Response: Available	1,226	1,281	4.5%
Net Internal Demand	30,823	30,260	-1.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	37,216	37,867	1.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	2,932	1,585	-45.9%
Anticipated Resources	40,148	39,452	-1.7%
Existing-Other Capacity	0	0	-
Prospective Resources	40,148	39,452	-1.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.3%	30.4%	0.1
Prospective Reserve Margin	30.3%	30.4%	0.1
Reference Margin Level	15.0%	15.0%	0.0

NPCC-New England			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	25,111	25,294	0.7%
Demand Response: Available	447	661	47.9%
Net Internal Demand	24,664	24,633	-0.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	27,997	27,255	-2.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,030	1,297	25.9%
Anticipated Resources	29,027	28,552	-1.6%
Existing-Other Capacity	872	138	-84.2%
Prospective Resources	29,899	28,690	-4.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	17.7%	15.9%	-1.8
Prospective Reserve Margin	21.2%	16.5%	-4.7
Reference Margin Level	12.0%	12.9%	0.9

NPCC-Ontario			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	22,439	22,753	1.4%
Demand Response: Available	687	996	45.0%
Net Internal Demand	21,752	21,757	0.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	24,575	26,856	9.3%
Tier 1 Planned Capacity	9	9	-1.6%
Net Firm Capacity Transfers	223	600	169.1%
Anticipated Resources	24,807	27,465	10.7%
Existing-Other Capacity	0	0	-
Prospective Resources	24,807	27,465	10.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	14.0%	26.2%	12.2
Prospective Reserve Margin	14.0%	26.2%	12.2
Reference Margin Level	13.2%	12.8%	-0.5

NPCC-Québec			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	22,859	22,922	0.3%
Demand Response: Available	0	0	-
Net Internal Demand	22,859	22,922	0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	33,690	35,731	6.1%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-2,353	-2,689	14.3%
Anticipated Resources	31,337	33,042	5.4%
Existing-Other Capacity	0	0	-
Prospective Resources	31,337	33,042	5.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	37.1%	44.1%	7.0
Prospective Reserve Margin	37.1%	44.1%	7.0
Reference Margin Level	11.0%	11.5%	0.5

SERC-Central			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	42,223	42,636	1.0%
Demand Response: Available	1,910	1,941	1.6%
Net Internal Demand	40,313	40,695	0.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	46,964	48,677	3.6%
Tier 1 Planned Capacity	93	332	257.3%
Net Firm Capacity Transfers	1,068	2,592	142.7%
Anticipated Resources	47,556	51,601	8.5%
Existing-Other Capacity	2,313	2,074	-10.3%
Prospective Resources	49,868	51,083	2.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	18.0%	26.8%	8.8
Prospective Reserve Margin	23.7%	25.5%	1.8
Reference Margin Level	15.0%	15.0%	0.0

PJM			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	149,059	151,247	1.5%
Demand Response: Available	7,288	7,756	6.4%
Net Internal Demand	141,771	143,491	1.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	186,540	183,690	-1.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	463	-607	-231.1%
Anticipated Resources	187,003	183,083	-2.1%
Existing-Other Capacity	0	0	-
Prospective Resources	187,466	182,476	-2.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	31.9%	27.6%	-4.3
Prospective Reserve Margin	32.2%	27.2%	-5.0
Reference Margin Level	14.9%	17.7%	2.8

SERC-East			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	43,889	43,567	-0.7%
Demand Response: Available	1,008	985	-2.3%
Net Internal Demand	42,881	42,582	-0.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	50,452	51,304	1.7%
Tier 1 Planned Capacity	0	122	-
Net Firm Capacity Transfers	624	593	-5.0%
Anticipated Resources	51,076	52,019	1.8%
Existing-Other Capacity	1,182	1,131	-4.3%
Prospective Resources	52,258	52,557	0.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	19.1%	22.2%	3.1
Prospective Reserve Margin	21.9%	23.4%	1.5
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	52,195	53,293	2.1%
Demand Response: Available	2,898	2,824	-2.6%
Net Internal Demand	49,297	50,469	2.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	60,074	60,962	1.5%
Tier 1 Planned Capacity	1,742	34	-98.0%
Net Firm Capacity Transfers	589	200	-66.0%
Anticipated Resources	62,405	61,196	-1.9%
Existing-Other Capacity	776	985	27.0%
Prospective Resources	63,181	61,981	-1.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.6%	21.3%	-5.3
Prospective Reserve Margin	28.2%	22.8%	-5.4
Reference Margin Level	15.0%	15.0%	0.0

Texas RE-ERCOT			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	82,307	84,818	3.1%
Demand Response: Available	3,380	3,496	3.4%
Net Internal Demand	78,927	81,323	3.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	94,580	99,541	5.2%
Tier 1 Planned Capacity	2,445	2,578	5.4%
Net Firm Capacity Transfers	20	20	0.0%
Anticipated Resources	97,045	102,139	5.2%
Existing-Other Capacity	0	0	-
Prospective Resources	97,073	102,167	5.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	23.0%	25.6%	2.6
Prospective Reserve Margin	23.0%	25.6%	2.6
Reference Margin Level	13.75%	13.75%	0.0

SERC-Southeast			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	46,127	46,021	-0.2%
Demand Response: Available	2,010	1,599	-20.4%
Net Internal Demand	44,117	44,422	0.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	59,559	63,918	7.3%
Tier 1 Planned Capacity	2,865	1,738	-39.4%
Net Firm Capacity Transfers	-815	-1,192	46.3%
Anticipated Resources	61,609	64,463	4.6%
Existing-Other Capacity	908	785	-13.5%
Prospective Resources	62,517	66,441	6.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	39.6%	45.1%	5.5
Prospective Reserve Margin	41.7%	49.6%	7.9
Reference Margin Level	15.0%	15.0%	0.0

WECC-AB			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,206	12,201	8.9%
Demand Response: Available	0	0	-
Net Internal Demand	11,206	12,201	8.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,759	13,941	1.3%
Tier 1 Planned Capacity	227	1,981	772.7%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	13,986	15,922	13.8%
Existing-Other Capacity	0	0	-
Prospective Resources	13,986	15,922	13.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.8%	30.5%	5.7
Prospective Reserve Margin	24.8%	30.5%	5.7
Reference Margin Level	9.9%	6.7%	-3.2

WECC-BC			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	8,636	9,275	7.4%
Demand Response: Available	0	0	-
Net Internal Demand	8,636	9,275	7.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	11,135	11,022	-1.0%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	11,135	11,022	-1.0%
Existing-Other Capacity	0	0	-
Prospective Resources	11,135	11,022	-1.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	28.9%	18.8%	-10.1
Prospective Reserve Margin	28.9%	18.8%	-10.1
Reference Margin Level	9.7%	12.0%	-2.4

WECC-CA / MX			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	56,356	54,029	-4.1%
Demand Response: Available	862	810	-6.0%
Net Internal Demand	55,494	53,219	-4.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	69,408	70,841	2.1%
Tier 1 Planned Capacity	5,522	6,906	25.1%
Net Firm Capacity Transfers	0	340	-
Anticipated Resources	74,930	78,087	4.2%
Existing-Other Capacity	0	0	-
Prospective Resources	74,930	78,087	4.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	35.0%	46.7%	11.7
Prospective Reserve Margin	35.0%	46.7%	11.7
Reference Margin Level	16.8%	21.5%	4.7

WECC-SW			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	25,992	26,661	2.6%
Demand Response: Available	380	278	-26.8%
Net Internal Demand	25,612	26,383	3.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	26,206	28,336	8.1%
Tier 1 Planned Capacity	1,655	2,338	41.3%
Net Firm Capacity Transfers	2,747	1,523	-44.6%
Anticipated Resources	30,608	32,197	5.2%
Existing-Other Capacity	0	0	-
Prospective Resources	30,608	32,197	5.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	19.5%	22.0%	2.5
Prospective Reserve Margin	19.5%	22.0%	2.5
Reference Margin Level	10.8%	10.5%	-0.3

WECC-NW			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	66,366	63,865	-3.8%
Demand Response: Available	1,038	907	-12.6%
Net Internal Demand	65,328	62,958	-3.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	76,587	78,057	1.9%
Tier 1 Planned Capacity	2,350	4,089	74.0%
Net Firm Capacity Transfers	5,004	3,192	-36.2%
Anticipated Resources	83,941	85,338	1.7%
Existing-Other Capacity	0	0	-
Prospective Resources	83,941	85,338	1.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	28.5%	35.5%	7.0
Prospective Reserve Margin	28.5%	35.5%	7.0
Reference Margin Level	16.3%	16.4%	0.1

Variable Energy Resource Contributions

Because the electrical output of variable energy resources (e.g., wind, solar PV) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity. The following table shows the capacity contribution of existing wind and solar PV resources at the peak demand hour for each assessment area. Resource contributions are also aggregated by Interconnection and across the entire BPS. For NERC's analysis of risk periods after peak demand (e.g., U.S. assessment areas in WECC), lower contributions of solar PV resources are used because output is diminished during evening periods.

BPS Variable Energy Resources by Assessment Area

	Wind			Solar			Hydro			Energy Storage Systems (ESS)		
Assessment Area / Interconnection	Nameplate Wind	Expected Wind	Expected Share of Nameplate (%)	Nameplate Solar PV	Expected Solar PV	Expected Share of Nameplate (%)	Nameplate Hydro	Expected Hydro	Expected Share of Nameplate (%)	Nameplate ESS	Expected ESS	Expected Share of Nameplate (%)
MISO	30,931	5,599	18%	10,169	4,981	49%	1,621	1,488	92%	2,678	2,591	97%
MRO-Manitoba Hydro	259	48	19%	–	-	0%	202	92	46%	-	-	0%
MRO-SaskPower	616	208	34%	30	6	21%	848	655	77%	-	-	0%
NPCC-Maritimes	1,209	262	22%	69	-	0%	1,312	1,181	90%	13	13	100%
NPCC-New England	1,546	122	8%	3,246	1,111	34%	550	367	67%	2,077	2,038	98%
NPCC-New York	2,590	340	13%	370	53	14%	984	386	39%	20	-	0%
NPCC-Ontario	4,883	720	15%	478	66	14%	8,922	5,171	58%	-	-	0%
NPCC-Québec	3,820	-	0%	10	-	0%	446	446	100%	-	-	0%
PJM	10,495	1,703	16%	10,990	5,694	52%	2,505	2,505	100%	190	151	79%
SERC-Central	1,220	172	14%	2,074	996	48%	4,966	3,332	67%	166	70	42%
SERC-East	-	-	-	2,769	2,405	87%	3,072	3,016	98%	24	10	43%
SERC-Florida Peninsula	-	-	0%	10,023	5,643	56%	-	-	0%	538	538	100%
SERC-Southeast	-	-	0%	7,887	7,217	91%	3,303	3,259	99%	115	105	92%
SPP	34,783	5,876	17%	756	486	64%	107	54	50%	12	2	13%
Texas RE-ERCOT	39,069	9,070	23%	24,463	17,797	73%	575	450	78%	7,876	2,661	34%
WECC-AB	4,482	666	15%	1,650	786	48%	894	450	50%	190	185	97%
WECC-BC	747	140	19%	2	0	22%	16,521	9,757	59%	-	-	0%
WECC-CA/MX	7,694	1,124	15%	21,790	13,147	60%	13,725	6,265	46%	7,295	6,858	94%
WECC-NW	19,709	2,964	15%	8,853	2,595	29%	41,705	24,147	58%	779	707	91%
WECC-SW	3,329	542	16%	2,690	1,294	48%	1,201	670	56%	988	893	90%
EASTERN INTERCONNECTION	88,702	15,220	17%	48,862	28,657	59%	28,394	21,507	76%	5,832	5,517	95%
QUÉBEC INTERCONNECTION	3,820	-	0%	10	-	0%	446	446	100%	-	-	0%
TEXAS INTERCONNECTION	39,069	9,070	23%	24,463	17,797	73%	575	450	78%	7,876	2,661	34%
WECC INTERCONNECTION	35,961	5,436	15%	34,985	17,822	51%	74,046	41,289	56%	9,252	8,643	93%
All INTERCONNECTIONS	**167,552**	**29,725**	**18%**	**108,320**	**64,277**	**59%**	**103,461**	**63,692**	**62%**	**22,960**	**16,821**	**73%**

Review of 2023 Capacity and Energy Performance

High temperatures, wildfires, and weather conditions challenged electric grid operators in many parts of North America to maintain a reliable supply of electricity during 2023. Prior to summer, NERC warned that much of North America was at risk of having insufficient resources to meet electricity demand if extreme temperatures and weather conditions were to develop. It is noteworthy that, after a summer of soaring temperatures, extended heat waves, and new electricity demand records, few high-level EEAs were issued, and no disruptions occurred as a result of inadequate resources. Nonetheless, operators at BAs, TOPs, and RCs faced significant challenges and drew upon procedures and protocols to obtain all available resources, manage system demand, and ensure the flow of supplies over the transmission network. Additionally, load-serving entities and state and local officials in many parts of North America used mechanisms and public appeals to lower customer demand during periods of strained supplies. The following section describes actual demand and resource levels in comparison with NERC's *2023 SRA* and summarizes 2023 resource adequacy events.

Eastern Interconnection–Canada and Québec Interconnection

Systems in parts of Canada experienced challenging conditions early in the summer from high electricity demand and wildfires over large areas. Electricity transfers from Québec to neighboring Maritimes and New England were curtailed or disrupted during periods in May and June when wildfires affected transmission facilities. Peak electricity demand in Ontario occurred in early September at a level near the 90/10 demand forecast. Additional imports helped the area meet the extreme demand.

Manitoba Hydro and SaskPower both experienced peak electricity demand in excess of 90/10 summer forecasts. Manitoba Hydro's peak occurred at the start of summer in June. Operators had sufficient reserves and were able to export supplies during the peak period to neighboring areas.

SaskPower peak electricity demand occurred in late July. A forced outage at a large thermal generator early in the summer contributed to operating challenges over much of the summer period. At the time of peak demand, forced outages were significantly higher than typical for summer peak periods.

Eastern Interconnection–United States

In SPP, summer electricity demand peaked in August and exceeded 90/10 forecasts. At the hour of peak demand, SPP experienced near-normal levels of forced thermal generation outages. Wind resource performance at the time of peak demand exceeded seasonal peak forecasts, helping to alleviate the strain on supplies. However, during periods in June and July, operators at SPP issued resource advisories during periods of forecasted high demand and low or uncertain wind resource output.

MISO also experienced peak electricity demand during the same period in August; however, demand was between the normal and 90/10 summer peak forecast levels. Wind and solar resource output at the time of peak demand were below expectations for summer on-peak contributions. Forced outages of thermal units, however, were lower than expected. An EEA (level 2) was issued in August due to high forecasted loads and wind uncertainty. MISO used operating procedures to ensure that sufficient reserves were maintained during periods of high electricity demand and high forced generator outages at times throughout the summer.

PJM experienced peak electricity demand in late July at a level between normal summer peak and the 90/10 forecast. Wind and solar resource output were below seasonal peak expectations, while low thermal generator outages were reported.

Peak electricity demand at NYISO and ISO-NE occurred in early September and fell below average summer peak forecasts.

Systems in the U.S. Southeast experienced peak demand above the 90/10 forecasts in mid to late August. Solar resource output exceeded the expected contributions for the peak demand period. Electricity imports into resource-constrained areas helped BAs maintain reserves during high demand periods.

Texas Interconnection–ERCOT

Extended heat waves led to record-setting system electricity demand in the ERCOT system throughout Summer 2023. Peak electricity demand occurred in mid-August at a level exceeding the 90/10 demand forecast. At the time of peak demand, wind and solar generation were slightly below expected levels for peak demand periods, and thermal generator outages were also slightly higher than normal for peak periods. Nonetheless, operators were able to maintain sufficient reserves. At various times throughout the summer, ERCOT issued public appeals for conservation to help manage high demand periods and evening periods when output from the solar resources is diminished. On September 6, ERCOT declared an EEA (level 2) to address a low-frequency condition on the system during a period of unusually high demand, declining solar output, and low wind output. Transmission system constraints led to the curtailment of some supply from wind resources in southern parts of the system. No load was shed during the event.

Western Interconnection–Canada

At the start of summer, the province of Alberta was in a state of emergency as a result of active wildfires and the threat of spreading from hot and dry conditions. A period of high demand from heat and humidity that coincided with generator forced outages and low wind conditions triggered an EEA. Alberta's system peak demand occurred in late July at a level above normal summer peak demand forecasts but below the 90/10 level. Wind and solar resource outputs were above seasonal forecast levels for peak demand periods. High temperatures in late August led to high demand at a time of planned transmission system maintenance. An EEA (level 3) was triggered when low wind conditions and insufficient imports resulted in reserve shortage.

The BC Hydro system also experienced peak electricity demand in early August at a level near the 90/10 summer peak forecast.

Western Interconnection–United States

The California-Mexico assessment area, which consists of the CAISO, Northern California, and CENACE BAs, experienced system peak electricity demand in mid-August at a level between the average summer peak demand forecast and the 90/10 peak demand forecast. Public appeals to shift electricity use to off-peak hours were used during some high-demand periods. The Mexico portion of the assessment area faced reserve shortages during periods in July and August as a result of high demand, generator outages, and unavailability of imports.

System peak electricity demand in the U.S. Northwest also occurred in mid-August and was below normal summer peak demand forecasts.

The U.S. Southwest experienced extended heat conditions and demand levels that exceeded normal summer peak demand forecasts. Wind and solar output fell below expected levels during the peak demand period.

2023 Summer Demand and Generation Summary at Peak Demand							
Assessment Area	Actual Peak Demand[1] (GW)	SRA Peak Demand Scenarios[2] (GW)	Wind – Actual[1] (MW)	Wind – Expected[3] (MW)	Solar – Actual[1] (MW)	Solar – Expected[3] (MW)	Forced Outages Summary[4] (MW)
MISO	120.8	116.8 123.9	8,598	5,488	2,096	3,750	6,638
MRO-Manitoba Hydro	3.5	3.1 3.4	83	47	-		95
MRO-SaskPower	3.7	3.5 3.6	381	203	15		737
MRO-SPP	56.0	52.6 55.1	8,278	4,500	130	378	6,533
NPCC-Maritimes	3.5	3.3 3.6	131	255	40	-	1,690*
NPCC-New England	23.5	24.7 26.5	186	186	145	1,163	1,969
NPCC-New York	30.2	30.8 32.7	223	331	-	84	9,716
NPCC-Ontario	23.7	21.8 23.7	786	771	200	126	3,419*
NPCC-Québec	22.5	22.9 22.9	496	-	8		12,287*
PJM	147.6	141.8 162.7	1,278	1,688	1,826	2,984	8,020
SERC-C	44.0	40.3 43.0	15	564	673	511	1,225
SERC-E	43.3	42.9 45.6	-	-	3,032	1,473	2,129
SERC-FP	54.1	49.3 52.4	-	-	4,590	4,534	1,610
SERC-SE	45.6	44.8	-	-	2,781	4,647	2,334
TRE-ERCOT	85.4	78.9 82.3	9,557	10,293	10,431	12,509	6,699
WECC-AB	11.5	11.2 11.6	906	309	894	763	-
WECC-BC	9.2	8.6 9.2	373	137	0	1	-

2023 Summer Demand and Generation Summary at Peak Demand							
Assessment Area	**Actual Peak Demand[1] (GW)**	**SRA Peak Demand Scenarios[2] (GW)**	**Wind – Actual[1] (MW)**	**Wind – Expected[3] (MW)**	**Solar – Actual[1] (MW)**	**Solar – Expected[3] (MW)**	**Forced Outages Summary[4] (MW)**
WECC-CA/MX	52.3	49.5 58.1	1,074	1,111	6,930	14,489	2,444
WECC-NW	64.7	61.0 67.2	2,137	593	3,821	1,411	4,855
WECC-SW	27.3	25.6 28.0	835	3,968	1,731	5,062	2,507
Highlighting Notes:	Actual peak demand in the highlighted areas met or exceeded extreme scenario levels.		Actual wind output in highlighted areas was significantly below seasonal forecast.		Actual solar output in highlighted areas was significantly below seasonal forecast.		Actual forced outages above or below forecast by factor of two

Table Notes:

[1] Actual demand, wind, and solar values for the hour of peak demand in U.S. areas were obtained from EIA From 930 data. For areas in Canada, this data was provided to NERC by system operators and utilities.

[2] See NERC *2023 SRA* demand scenarios for each assessment area (pp. 14–33). Values represent the normal summer peak demand forecast and an extreme peak demand forecast that represents a 90/10, or once-per-decade, peak demand. Some areas use other basis for extreme peak demand.

[3] Expected values of wind and solar resources from the *2023 SRA*.

[4] Values from NERC Generator Availability Data System for the 2023 summer hour of peak demand in each assessment area. Highlighted areas had actual forced outages that were more than twice the value for typical forced outage rates used in the 2023 summer risk period scenarios in the *2023 SRA*.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-9

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

Exhibit 43

Winter Storm Elliott System Operations Inquiry

Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott

FERC, NERC and Regional Entity Staff Report
October 2023



Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott

FERC, NERC and Regional Entity Staff Report
October 2023



FEDERAL ENERGY REGULATORY COMMISSION

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Regional Entities:
Midwest Reliability Organization, Northeast Power Coordinating Council, ReliabilityFirst Corporation, SERC Corporation, Texas Reliability Entity and Western Electricity Coordinating Council

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I. EXECUTIVE SUMMARY

This report describes how the extreme cold weather event occurring between December 21 and 26, 2022 (Winter Storm Elliott) impacted the reliability of the Bulk Electric System ("BES" or colloquially known as the grid) and the supporting natural gas infrastructure in the U.S. Eastern Interconnection[1] ("the Event").[2] During the Event, 1,702 individual BES[3] generating units in the Eastern Interconnection experienced 3,565 unplanned outages, derates, or failures to start.[4] Each individual unit could, and often did, have multiple outages from the same or different causes. At the worst point of the Event, there were 90,500 MW of coincident unplanned generating unit outages, derates and failures to start (meaning they all occurred at the same time). Including generation that was already out of service,[5] a total of over 127,000 MW of generation was unavailable, representing 18 percent of the U.S. portion of the anticipated resources in the Eastern Interconnection.

The Event was the **fifth** in the past **11** years in which

1 There are four interconnections in North America, with three of those interconnections encompassing the lower 48 states: the Eastern Interconnection; the ERCOT Interconnection; and the Western Interconnection. NERC Interconnections, available at https://www.nerc.com/AboutNERC/keyplayers/PublishingImages/NERC%20Interconnections.pdf. *See also*, FERC Reliability Primer, 11 (2020), https://www.ferc.gov/media/2135.

2 This is a staff report, and does not speak for the Commission, NERC or any of the Regional Entities. ***See*** Press Release, FERC, NERC to Open Joint Inquiry into Winter Storm Elliott (December 28, 2022) for a description of the inquiry's commencement. *See* Appendix A for list of the Winter Storm Elliott Inquiry joint team members (the "Team"). The Team of over 50 subject matter experts from the Commission, NERC and all of its Regional Entities: Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), ReliabilityFirst Corporation (RF), SERC Corporation (SERC), Texas Reliability Entity (TRE) and the Western Electricity Coordinating Council (WECC); as well as the National Oceanic and Atmospheric Administration (NOAA), was formed shortly after the Event determine the causes of the Event and make recommendations to prevent recurrence of the effects that the extreme cold weather caused for the grid. Appendix B includes a list of acronyms Used in the Report. The Report is written for a reader who is already familiar with principles of energy markets, electric transmission operations, generating unit operations, and natural gas production, processing, and transportation. For readers who are not as familiar, the staff Primers on Electric and Natural Gas Markets detail the essential principles related to energy markets, electric transmission operations, generating unit operations, and natural gas production, processing, and transportation, *see* FERC Energy Primer (https://www.ferc.gov/media/energy-primer-handbook-energy-market-basics) and FERC Reliability Primer (https://www.ferc.gov/sites/default/files/2020-04/reliability-primer_1.pdf).

3 The Commission's jurisdiction extends to the Bulk-Power System, defined by Section 215(a) (1) of the Federal Power Act as "facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof), and electric energy from generating facilities needed to maintain transmission system reliability." The mandatory Reliability Standards apply to owners and operators of the Bulk Electric System (BES). In Order No. 773, the Commission approved a definition of BES that generally covers all elements operated at 100 kV or higher, with a list of specific inclusions and exclusions. Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure, Order No. 773, 141 FERC ¶ 61,236 (2012); order on reh'g, Order No. 773-A, 143 FERC ¶ 61,053 (2013), order on reh'g and clarification, 144 FERC ¶ 61,174 (2013). This report will use BES because its primary audience is most familiar with that term. There were some non-BES generating units (i.e., that did not meet the BES definition in the NERC Glossary of Terms) that experienced outages, derates, or failures to start within the Eastern Interconnection but the Team did not request data from them and they are not included in its analysis. By definition these units would be less than 20 MW individually or 75 MW in the aggregate with a common point of connection (e.g. a wind or solar facility). https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf .

4 The Team obtained generating unit data directly from the Generator Owners and/or Operators (GOs/GOPs).

5 Those units that were already out of service included generating units undergoing planned maintenance outages and those units that incurred forced outages before the Event, that had not yet returned to service during the worst point of the Event.

unplanned cold weather-related generation outages jeopardized grid reliability.[6] Several Balancing Authorities (BAs) (grid operators that balance demand and electric energy) in the southeast U.S. needed to shed firm load during the Event to maintain system reliability, which in total (at different points in time) exceeded 5,400 MW. This was the largest controlled firm load shed recorded in the history of the Eastern Interconnection. Just one year before, in 2021, the Winter Storm Uri event in Texas and the South Central U.S. saw the largest controlled firm load shed event in U.S. history, with over 20,000 MW of firm load shed (20,000 MW in ERCOT alone). In that event, more than 4.5 million people lost power in Texas, and some went without power for as long as four days, while exposed to below freezing temperatures for as long as six days. Estimates of those who died during that event, primarily from causes connected to the power outages including hypothermia, carbon monoxide poisoning, and medical conditions exacerbated by freezing conditions, range from over 200 to over 800.[7] The Federal Reserve Bank of Dallas estimated the direct and indirect losses to the Texas economy from that event to be between $80 and $130 billion.[8]

The quantity of firm load shed during Winter Storm Elliott was not as large as in the Winter Storm Uri event, but it is especially disconcerting that it happened in the Eastern Interconnection which normally has ample generation and transmission ties to other grid operators that allow them to import and export power. And yet, for reasons described more fully in Section IV of the Report, electric grid operators were faced with a generation capacity shortage that resulted in 5,400 MW of firm load shed.

6 In February 2011, an arctic cold front impacted the southwest U.S. and resulted in 29,700 MW of generation outages, natural gas facility outages, and emergency power grid conditions with need for firm customer load shed. Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011: Causes and Recommendations (Aug. 2011), Report on outages and curtailments during the Southwest cold weather event (ferc.gov) ("2011 Report"). In January 2014, a polar vortex affected Texas, central and eastern U.S., triggering 19,500 MW of generation outages, and natural gas availability issues resulting in emergency conditions including voluntary load management. NERC "Polar Vortex Review" (Sept. 2014), https://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf ("Polar Vortex Review"). In January 2018, an arctic high-pressure system and below average temperatures in the South Central U.S. resulted in 15,800 MW of generation outages and the need for voluntary load management emergency measures. South Central United States Cold Weather Bulk Electric Systems Event of January 17, 2018 (July 2019), https://www.ferc.gov/sites/default/files/2020-07/SouthCentralUnitedStatesColdWeatherBulkElectricSystemEventofJanuary17-2018.pdf ("2018 Report"). Finally, in February 2021, extreme cold weather and freezing precipitation in Texas and the South Central U.S. resulted in generating outages of over 60,000 MW and over 20,000 MW of firm load shed. The February 2021 Cold Weather Outages in Texas and the South Central United States | FERC, NERC and Regional Entity Staff Report (Nov. 2021), The February 2021 Cold Weather Outages in Texas and the South Central United States | FERC, NERC and Regional Entity Staff Report | Federal Energy Regulatory Commission ("2021 Report").

7 Recent "excess death" analyses of deaths in Texas during the 2021 event range as high as 800. Amber Weber & Mose Buchele , *Texas has an official death count from the 2021 blackout. The true toll may never be known*., Texas Standard (Aug. 15, 2022),Texas has an official death count from the 2021 blackout. The true toll may never be known. | Texas Standard.

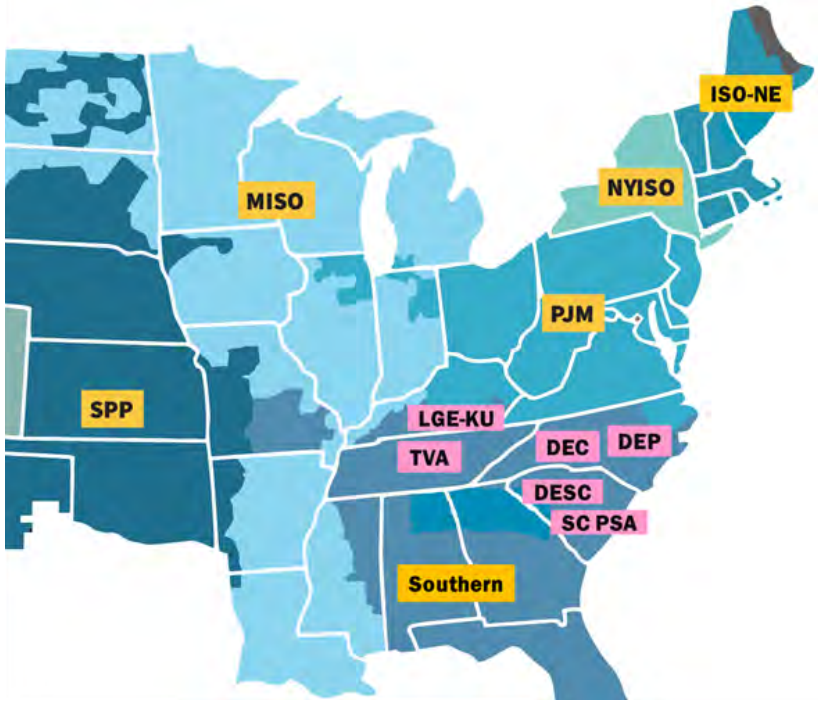
8 Garrett Golding et al., *Cost of Texas' 2021 Deep Freeze Justifies Weatherization*, Dallas Fed. Economics (Apr. 15, 2021), https://www.dallasfed.org/research/economics/2021/0415.

A. Synopsis of Event

The storm that came to be known as Winter Storm Elliott, variously characterized as a bomb cyclone and an extra-tropical cyclone,[9] moved from the upper Plains states eastward. By Wednesday, December 21, 2022, it reached the central U.S., eventually blanketing most of the eastern United States on December 23 and 24, and did not subside until December 26. In an unacceptably familiar pattern, the cold temperatures ushered in electric generation outages that coincided with winter peak electricity demands (i.e., winter peak loads), and resulted in many BAs declaring energy emergencies. The amount of generation that failed during the Event was unprecedented—90,500 MW in coincident unplanned outages.[10] The coincident incremental[11] unplanned generation outages *alone* represented 13 percent of the U.S. portion of the winter 2022-2023 anticipated generation resources in the Eastern Interconnection.[12]

Figure 1, below, shows the entities in the U.S. Eastern Interconnection most affected by Winter Storm Elliott, referred to as the "Event Area." The entities represented by a pink box shed firm load at some point during the Event, including Tennessee Valley Authority (TVA), Louisiana Gas and Electric Company/Kentucky Utilities (LG&E/KU),

Figure 1: Bulk Electric System Map of Entities in the U.S. Eastern Interconnection Affected by the Extreme Cold Weather



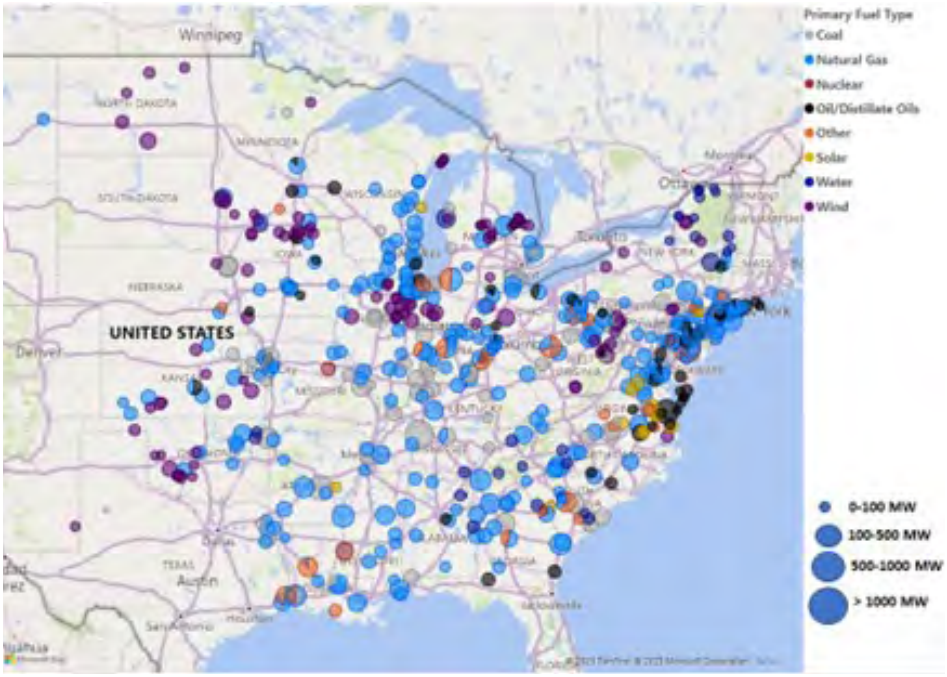
9 Both are terms that denote a storm associated with a rapid drop in pressure—the more rapid the drop in pressure, the more intense the storm. Pandora Dewan, *Bomb Cyclone Photos: What to Expect From Freezing Weather Forecast*., Newsweek (Dec. 20, 2022), https://www.newsweek.com/bomb-cyclone-photos-freezing-weather-forecast-1768515#:~:text=Elliott%20is%20expected%20to%20arrive%20in%20the%20Pacific,the%20Midwest%20and%20parts%20of%20the%20East%20Coast.

10 The 2021 Winter Storm Uri event had 65,622 MW coincident incremental unplanned generating unit outages, the most that occurred before the Event.

11 "Incremental" generating unit outages, derates, and failures to start refers to those which occurred during the Event (December 21-26, 2022), as compared to those which occurred before the Event.

12 Based on data from the NERC 2022-2023 Winter Reliability Assessment. The 18 percent of Eastern Interconnection resources reference earlier is for unplanned outages that occurred during the Event at the moment when the most generation was offline during the Event ("the worst point"), plus unplanned and planned outages that were already in effect at the beginning of the Event. NERC, *2022- 2023 Winter Reliability Assessment* (Nov. 2022), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2022.pdf.

Figure 2: Location and Fuel Type of Unplanned Generation Outages and Derates During the Event (Bubble Size by MW for each Outage), as of December 24, 2022



Duke Energy Progress (DEP) and Duke Energy Carolinas (DEC), Dominion Energy SC (DESC), and South Carolina Public Service Authority (Santee Cooper). Other entities issued Energy Emergency Alerts (EEAs),[13] but did not need to shed firm load, including PJM Interconnection, LLC (PJM), Southern Company (Southern), Midcontinent Independent System Operator (MISO), Southwest Power Pool (SPP), and ISO New England (ISO-NE). All of the affected entities experienced significant unplanned generating unit outages, derates, or failures to start within their footprints. See Figure 2, above, shows the approximate locations of the generating unit outages during the Event and their fuel type.

The 2021 Report attributed the unplanned generating outages to generating units unprepared for the cold weather and natural gas fuel supply issues:

> A confluence of two causes, both triggered by cold weather, led to the [Uri] Event, part of a recurring pattern for the last ten years. First, generating units unprepared for cold weather failed in large numbers. Second, in the wake of massive natural gas production declines, and to a lesser extent, declines in natural gas processing, the natural gas fuel supply struggled to meet both residential heating load and generating unit demand for natural gas, exacerbated by the increasing reliance by generating units on natural gas. Natural gas pipeline capacity is for the most part designed, certificated and constructed to accommodate firm transportation commitments, while many natural gas-fired generating units rely on non-firm commodity and/or pipeline transportation contracts.[14]

13 New York Independent System Operator (NYISO) did not declare an EEA during the Event.

14 2021 Report at 11-12.

The Event shows that, while some changes were implemented in response to previous cold weather events, generators and natural gas supply and infrastructure remain vulnerable to extreme cold weather.

Similar to other cold weather events,[15] the cold weather was forecast well in advance. Beginning with forecast colder weather mid-December, and with widespread warnings by December 20, grid operators knew that frigid weather was coming. Many issued cold weather preparation notices to their Generation and Transmission Owners and Operators. Temperatures were lower than normal during the Event, although not quite as far off normal lows as during the 2021 event. Winter Storm Elliott's departures from normal minimum lows were largely from 15 to 30 degrees lower than normal, though a small area was even lower. In Winter Storm Uri, departures from normal minimum lows ranged from 40 to 50 degrees lower than normal low temperatures. However, Winter Storm Elliott generally had higher winds than Uri, with gusts up to 60 miles per hour, which increased convective cooling. Rapid temperature drops to subfreezing levels across the eastern half of the U.S. occurred. For example, temperatures in Charleston, West Virginia dropped 42 degrees in six hours, and TVA reported a drop of 46 degrees in five hours. Some areas experienced blizzard conditions. Geographically, Winter Storm Elliott was a very large storm. At approximately 2,000 miles wide, its extreme cold and high winds covered the eastern two-thirds of the lower 48 U.S.

Winter Storm Elliott caused unplanned outages of natural gas wellheads due to wellhead freeze-offs and other frozen equipment. Weather-related poor road conditions prevented necessary maintenance.[16] This led to significant natural gas production decreases, which also occurred during the 2011 and 2021 events.[17] During the Event, "[d]ry natural gas production in the Lower 48 states dropped to a low of 82.5 Bcf on December 24, a 16 percent decrease (16.1 Bcf/d) from December 21...."[18] Gas production experienced the greatest declines in the Marcellus and Utica Shale formations, where it dropped by 23 to 54 percent during the Event.[19] Figure 3, below, shows the areas where production decreases occurred.

The affected grid operators, beginning with SPP and then MISO, saw rising load and increasing generating unit outages during the Event, which in many cases led to a reduction in their energy reserves. Neither SPP nor MISO needed to shed firm load throughout their footprints,[21] but, to combat the rising loads and generation outages, SPP twice curtailed non-firm exports on December 23 because its reserves were low. MISO and SPP closely coordinated on the Regional Directional Transfer Limit between MISO South and the rest of MISO (see Figures 41 and 42), twice lowering the limit at SPP's request.[22]

15 *See* Figure 4 below, for a side-by-side comparison of the past five extreme cold weather events in 11 years. For additional information on extreme cold weather conditions during the events, *see* the 2021 Report, Appendix B: Comparison of Similar Severe Weather Events, at 245.

16 The Team also obtained natural gas production and processing data directly from owners of these facilities, unless otherwise stated. However, because these entities are not subject to the Commission's jurisdiction, the Team did not receive all data requested.

17 The teams observed decreases in natural gas production in the 2011 and 2021 cold weather events. The teams studying the 2014 Polar Vortex and January 2018 events did not quantify natural gas production losses or investigate any causes for such losses.

18 James Easton and Max Ober, *U.S. natural gas consumption reached record daily high in late December 2022*, Today in Energy (Jan. 31, 2023), https://www.eia.gov/todayinenergy/detail.php?id=55359.

19 Source: S&P Global Commodity Insights, ©2023 by S&P Global Inc.

20 Source: EIA: Maps: Oil and Gas Exploration, Resources, and Production - Energy Information Administration (eia.gov), adapted from "Lower 48 Shale Plays."

21 SPP had a localized voltage issue caused by a combination of unplanned generating unit outages and transmission outages. Local transmission system operators initiated a [brief] firm load shed of 29 MW to alleviate issue. *See section* III.B.3.a), Thursday, December 22: Effects of Elliott begin to impact U.S. portion of Eastern Interconnection BES, for additional discussion.

22 Unplanned generation outages and underestimated loads in MISO's "South" region led it to increase its north-to-south power transfer to supply more power to that portion of its system. MISO agreed to limit its north-to-south transfer by half of its contractual limit (1,500 MW)..

On December 23, MISO declared EEA 1 and 2,[23] due to congestion on its transmission system and diminished generation deliverability and used 3,000 MW of Load Modifying Resources.[24] MISO also had several local transmission emergencies but did not need to shed any firm load.

Figure 3: Areas of Shale Natural Gas Production Where Extreme Cold Weather Occurred[25]



TVA experienced rapidly-increasing generating unit outages in the early morning hours of December 23. By 6 a.m. Eastern Standard Time,[26] TVA had lost over 5,000 MW of generation and declared EEA 1 and EEA 2. By 6:12 a.m., TVA declared EEA 3, which indicated that firm load shed was imminent, and secured emergency power from Duke, Southern, PJM, and MISO, but this solution was short-lived. As TVA continued to experience significant unplanned generation outages and increasing electricity demands, PJM needed to reduce the emergency power it was supplying to TVA, due to a transmission operating limit in PJM.[27] By 10:31 a.m., now faced with well over

23 *See* Reliability Standard EOP-011-2 - Emergency Preparedness and Operations, "Attachment 1-EOP-011-2 Energy Emergency Alerts" for the levels of alerts and energy emergencies, at https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-011-2.pdf. EEA levels indicate to neighboring Balancing Authorities that a Balancing Authority is experiencing an energy emergency and the level of severity. The Reliability Coordinator is responsible for declaring EEAs for its Balancing Authorities within its footprint per EOP-011-2, Requirement R6, and as detailed in Attachment 1.

24 Load Modifying Resources, or LMRs, are demand resources or behind-the-meter generation.

25 Source: EIA: Maps: Oil and Gas Exploration, Resources, and Production - Energy Information Administration (eia.gov), adapted from "Lower 48 Shale Plays."

26 All times stated within the Report, unless otherwise specified, are Eastern Standard Time (EST). If the entity is located in the Central Time Zone, all times were converted to EST.

27 PJM operators curtailed the emergency power schedule to TVA due to a System Operating Limit (SOL). The transmission facility at issue was exceeding its emergency limit in real time. *See also* sidebar on N-1 at 60.

6,000 MW of unplanned generating unit outages since midnight, continually rising system load, and depleted generation reserves, TVA ordered firm load shed of over 1,500 MW, which represented five percent of its peak system load.[28]

LG&E/KU also experienced significant unplanned generation derates during winter peak load conditions on the evening of December 23. To offset the generation derates, LG&E/KU was able to import 400 MW from PJM. At 4:29 p.m., PJM BA curtailed the 400 MW import due to experiencing rapidly increasing levels of unplanned generation outages coincident with increasing system load in its own footprint. In response, LG&E/KU requested emergency energy from the TVA Contingency Reserve Sharing Group, which TVA was able to supply. With its system load increasing, LG&E/KU entered into EEA 3 at 4:45 p.m. Following TVA's return at 5:18 p.m. to EEA 3, by 6:00 p.m. it also could no longer spare its 400 MW emergency power to LG&E/KU. With the loss of the import power to offset the unplanned generation derates, LG&E/KU began over 300 MW firm load shed at 5:58 p.m. This was the first time LG&E/KU had ever ordered firm load shed in response to an energy emergency (EEA) event.

Through the morning of December 24, PJM was providing emergency energy to neighboring Balancing Authorities, but as unplanned outages multiplied and its load increased, it needed to curtail those emergency energy export schedules and declared EEA 1 and EEA 2. PJM benefitted from a Simultaneous Activation of Ten-Minute Reserve (SAR) agreement with the Northeast Power Coordinating Council Balancing Authorities, which allowed PJM to call on reserves of up to 1,500 MW during the Event. PJM requested assistance under the SAR agreement five times between December 23 and 24. Although PJM said it was "close" to needing to shed firm load, it did not.[29]

Southern, like PJM, at first was able to provide emergency energy to other Balancing Authorities. By 6:25 a.m. on December 24, it declared EEA 2, having declared EEA 1 in the early morning hours. Southern obtained emergency energy from Florida Power and Light. The emergency energy import assisted Southern in meeting its all-time December record peak load early that morning and enabled it to provide emergency energy to DESC. DEC, DEP, DESC and Santee Cooper, Balancing Authorities in the Carolinas which form the Carolinas Reserve Sharing Group,[30] experienced escalating unplanned generating unit outages in the face of early morning peak load conditions. Combined with their inability to obtain import power from surrounding Balancing Authorities experiencing the same conditions, at worst points the four Balancing Authorities had to shed a combined total of over 2,000 MW firm load.

28 This was the first of two instances during Winter Storm Elliott where TVA needed to shed firm load. The other instance was during the early morning hours of December 24. From 6:12 a.m. on December 23 to midday December 24, TVA was at EEA 3, other than for a brief period the afternoon of December 23, when it was at EEA 2. Early the morning of December 24, TVA first ordered firm load shed of five percent of its peak system load, followed by an additional five percent reduction of firm load (in total, 10 percent of its peak system load which was **over 3,000 MW**). During those hours, most of TVA's neighboring BAs were faced with high electricity demands and escalating unplanned generating unit outages of their own and as a result, could not provide emergency power to TVA.

29 Although PJM was at an increased risk of load shedding approaching the morning peak on December 24, PJM still had options before shedding firm load, if it had lost another large generating unit or if NYISO had to cut its imports. PJM could have initiated a Voltage Reduction Action, which could have provided approximately 1,700 MW of relief. If necessary, PJM could have followed the Voltage Reduction with a Manual Load Dump Warning (providing Transmission Operators with their load allocations). Firm load shed would occur, if necessary, via Manual Load Dump Action, followed by issuance of EEA 3. PJM Report at 63.

30 *See*, CRSG, Dominion Energy South Carolina, Inc. OATT & SA, § SA No. 239, CRSG Operating Manual (0.0.0), https://etariff.ferc.gov/TariffSectionDetails.aspx?tid=6293&sid=312207.

B. Recurrence of Cold Weather Events with Unplanned Generating Unit Outages and Implications

The 2021 Report noted, "the [2021 Winter Storm Uri event] was the fourth cold-weather-related event in the last ten years to jeopardize BES reliability," and that "in each of the four BES events, planned and unplanned generating unit outages caused energy emergencies and in 2011, 2014 and 2021 they triggered the need for firm load shed."[31] Each event's report made recommendations to reduce the likelihood of similar consequences in the future.

In several of the previous events, there have been close calls, meaning, that if conditions worsened, it could have resulted in widespread firm load shed or outages. During Uri, for example, ERCOT came within four minutes of a potential complete blackout of the ERCOT Interconnection if the interconnection frequency had not recovered. During the January 2018 cold weather event, had the worst contingency generating unit forced outage occurred in MISO South, its electric grid operators would have needed to rely on post-contingency manual firm load shed to maintain voltages within limits, while faced with potential additional firm load shedding to maintain system balance and restore reserves. The Event, too, had its share of close calls. The natural gas provider for Manhattan, The Bronx, and portions of Queens and Westchester County, Consolidated Edison (Con Edison), faced reliability-threatening low pressures at its citygate[32] on all the interstate natural gas pipelines that it relies upon. Con Edison maintained its natural gas local distribution system pressure by using its own liquified natural gas (LNG) facility, among other measures. Had Con Edison not activated its LNG facility and taken its other emergency measures, or had the cold weather lasted longer, it could have faced large scale outages. System outages for a local natural gas distribution company generally take longer to restore than firm load shed, or even cascading outages, on the electric grid. Once electricity is restored to a circuit, all of the homes[33] can return to their normal functioning—lights turn back on, heating or air conditioning systems return to normal function, etc. By contrast, for the natural gas local distribution system to return system outages to normal operation, workers must go house-to-house and individually light every pilot light. Con Edison estimated it would have taken months to restore service, even with mutual assistance from other utilities, had it experienced a complete loss of its system.

In addition to the close call with Con Edison, the Eastern Interconnection's normally robust electric grid one-minute average frequency dropped to 59.936 Hz, slightly below its low frequency trigger limit of 59.95 Hz.[34] The frequency began declining on the morning of December 24 at 3:25 a.m. and over the next hour steadily decreased

31 2021 Report at 9.

32 Citygate - a point or measuring station at which a distributing gas utility receives gas from a natural gas pipeline company or transmission system. *See* EIA Definitions, Sources and Explanatory Notes, at https://www.eia.gov/dnav/ng/TblDefs/ng_pri_sum_tbldef2.asp.

33 For those that do not have secondary outage causes.

34 Frequency as a measure of the reliability status of a power system provides a key indicator of the overall integrity of operations. 60.000 Hz is the nominal frequency for the Eastern Interconnection, and maintaining it requires generating units to automatically respond to deviations, BAs to perform moment-to-moment balancing of the system's aggregate generation output to its load and maintain sufficient responsive reserves available to withstand the sudden tripping of the largest generator on the system. The Low Frequency Trigger Limit is approximately 59.95 Hz for the Eastern Interconnection and is used by BAs to calculate their required response to frequency deviations that are below 60 Hz. *See* NERC Reliability Standard BAL-001-2 – Real Power Balancing Control Performance, Attachment 2. RSCompleteSet.pdf (nerc.com)

from 60.00 Hz, reaching its lowest point by 4:25 a.m. At that time, the composite ACE[35] for the Core Event Area[36] was -2,754 MW, and PJM BA's portion of the composite ACE was -2,162 MW (due in part to PJM experiencing an additional 1,400 MW in unplanned generation outages from 4:20 a.m. to 4:25 a.m.). Although the Eastern Interconnection frequency recovered to its normal range[37] as PJM and several other Balancing Authorities concurrently initiated more severe emergency energy actions (including firm load shed for some Balancing Authorities), total unplanned generation outages continued to increase over and above generation that was already out of service, reaching a combined total of over 127,000 MW by 10:00 a.m. This left 18 percent of the winter 2022-2023 anticipated generation resources in the U.S. portion of the Eastern Interconnection offline during winter peak conditions.[38] Including this occasion, as well as the evening of December 23, there were four points during the Event at which the one-minute average frequency declined below 59.95 Hz, coinciding with lower online responsive reserves[39] within the Core Event Area due to generation outages. Ultimately on the morning of December 24, grid operators maintained frequency by reducing electricity demand, including by shedding over 5,400 MW of firm load, leaving hundreds of thousands of customers[40] without electricity to heat homes for several hours during the extreme cold weather conditions.

35 ACE stands for Area Control Error, which is the minute-to-minute measure of how well the BA is performing its balancing function; i.e., balancing its scheduled power outputs to meet actual inputs and outputs. If ACE is less than zero, then the BA needs to increase generation supply/output in its footprint to balance; or if additional generation increase is not possible, the BA may need to curtail export power schedules, or worst case, reduce demand by shedding firm load.

36 The "Core Event Area" refers to the location where concurrent EEA 2 and EEA 3 energy emergency measures were taken by electric grid entities the morning of December 24, 2022 (i.e., concurrent EEA 2 load management and EEA 3 firm load shed measures) to maintain BES reliability. These grid entities are NERC-registered Balancing Authorities. They are referred to as Core Entities or Core BAs in the Report, and are depicted in Figure 9, below.

37 For the Eastern Interconnection, the normal range is 59.95 – 60.05 Hz.

38 This exceeds NERC's 2022-2023 Winter Reliability Assessment "worst case" low generation condition for the U.S. portion of the Eastern Interconnection (worst case is calculated by combining MW outage shortfall scenarios of: extreme low gen + low wind + natural gas risk scenario) by 32,500 MW of additional generation reductions.

39 Responsive reserves are those online reserves that are capable of responding and recovering from frequency deviations.

40 On December 24, 2022, TVA ordered its 153 local power companies (LPCs) serving 10 million people in Tennessee and parts of six surrounding states to interrupt 10 percent of their firm load. Tennessee Valley Authority After Action Report, at 20-21, ((https://www.tva.com/about-tva/reports)), and https://www.tva.com/about-tva#:~:text=The%20Tennessee%20Valley%20Authority%20provides,industrial%20customers%20and%20federal%20installations. Duke Energy reported to the North Carolina Utilities Commission that on December 24, approximately 15 percent of customers overall – roughly 500,000 in total – were impacted by the company's rotating outages. (https://news.duke-energy.com/releases/duke-energy-updates-north-carolina-utilities-commission-on-winter-storm-elliott-emergency-outage-event#:~:text=CHARLOTTE%2C%20N.C.%20%E2%80%93%20-Leaders%20from%20Duke,from%20occurring%20that%20way%20again.) During rolling blackouts [firm load shed] instituted by LG&E/KU, 54,637 customers were affected. *Kentucky Utilities Co. & Louisville Gas and Electric Co. Response* (Mar. 10, 2023), https://psc.ky.gov/pscecf/2022-00402/rick.lovekamp%40lge-ku.com/03102023103319/02-AG_DR1_LGE_KU_Responses.pdf.

Figure 4: Comparison of Events' Effects on Bulk Electric System Generation and Resulting Need for Load Shed

Event Date/ Duration:	SW U.S. Event/ Feb. 1-5, 2011	Polar Vortex/ Jan 6-8, 2014	2018 Event/ Jan 15-19, 2018	2021 Event/ Feb 8-20, 2021	2022 Event/ Dec 21-26, 2022
Deviation from Average Daily Temperature	17 to 36 deg. below average	20 to 30 deg. below average	12 to 28 deg. below average	40 to 50 deg. below average	20 to 30 deg. below average
Geographic Area of Event	Texas and Southwest U.S.	Midwest, South Central, and East Coast regions	South Central U.S.	Texas and South Central U.S.	Central, Midwest, and large parts of Southeast and Northeast U.S.
Event Area Sq. Miles (approx.)	656,300	1,923,000	418,000	869,600	1,517,000
Unavailable Generation Due to Cold Weather, at Worst Point (MW)	14,702	9,800	15,600	65,622	90,500
Causes of Unavailable Generation (in alphabetical order)	Freezing Issues, Mechanical/ Electrical Issues, Natural Gas Fuel Issues	Freezing Issues (cold weather), Natural Gas Fuel Issues	Freezing Issues, Mechanical/ Electrical Issues, Natural Gas Fuel Issues	Freezing Issues, Natural Gas Fuel Issues, Mechanical/ Electrical Issues	Freezing Issues, Mechanical/ Electrical Issues, Natural Gas Fuel Issues
Energy Emergency Declared/ Highest Level	Yes/ EEA 3	Yes/ EEA 3	Yes/ EEA 2	Yes/ EEA 3	Yes/ EEA 3
Maximum Level of Firm Load Shed (MW)	5,411.6	300	0	23,418 (ERCOT 20,000, SPP 2,718, MISO South 700)	Over 5,400[41] Total (TVA over 3,000, DEC 1,000, DEP 961, LG&E/ KU 317,[42] DESC 94.7,[43] Santee Cooper 86.4)
Overall Duration of Firm Load Shed	ERCOT: 7 hours, 24 minutes	3 hours	N/A	ERCOT: over 70 hours, SPP: over 4 hours MISO South: over 2 hours	TVA: 7 hours, DEC: 3 hours, DEP: 2 hours, LG&E/KU: 4 hours, DESC and Santee Cooper: 9, and 17 min., respectively

41 Total of entities' maximum load shed ordered, which occurred on December 23 and 24, 2022 at different times. Section III.B.3. of the report describes more details on the magnitudes and timeframes of firm load shed for each entity.

42 317 MW was initial level of firm load shed. Load shed levels were decreased over duration.

43 94.7 MW was initial magnitude of firm load shed. After 2 minutes, load shed levels were decreased over duration.

Figure 5: Similarities to Past Extreme Cold Weather Events

	2011 Event	2014 Event	2018 Event	2021 Event	2022 Event
Significant levels of incremental unplanned electric generating unit losses with top causes found to be mechanical/electrical, freezing, and fuel issues.	✓	✓	✓	✓	✓
Significant natural gas production decreases occurred, with some areas of the country more severely affected.	✓			✓	✓
Short-range forecasts of peak electricity demands were less than actual demands for BAs in event area.	✓		✓	✓	✓
Significant natural gas LDC outages or near miss.	✓				✓

As demonstrated by Figure 4, above, the Event was the fifth in the past 11 years in which unplanned cold-weather-related generation outages jeopardized grid reliability, and the fourth that triggered the need for firm load shed. Twice in 11 years the reliability of natural gas delivery to homes and businesses has been jeopardized. These recurring failures make clear that America's natural gas infrastructure and electric grid continue to be severely challenged during extreme cold weather events, repeatedly jeopardizing reliability during life-threatening conditions, even when technology exists to protect the vulnerable components.[44] Multiple extreme cold weather event reports, including the 2021 Report issued less than two years ago, have detailed the same three primary causes of the unplanned generating outages: Freezing Issues; Fuel Issues; and Mechanical/Electrical issues which are correlated with temperature, increasing in number as temperatures fall.[45]

Multiple extreme cold weather event reports made recommendations aimed at preventing recurrence of these events, and some progress has been made.[46] But some key drivers of these events remain unaddressed, especially the freezing of natural gas infrastructure. As noted in the NAESB Gas-Electric Harmonization Forum Report ("NAESB Report"):

> "In the last two decades, natural gas' fuel share for power generation has doubled: today it represents almost 40 percent of total resources. Both sectors of the American energy system have become highly interdependent economically and technically: natural gas represents the largest fuel resource for power generation, while power generation is the largest consumer of natural gas."[47]

44 *See* 2011 Report at 206-208 (recommendations on specific freeze protection maintenance measures); note 119 (methods to protect natural gas infrastructure), 2021 Report at 194-95 (Key Recommendation 6) (same).

45 Appendix E of the Report updates the progress on the recommendations from the 2021 Report.

46 Freezing-related generating unit outages are recognized as a significant driver of these events. As discussed below, Reliability Standards requiring appropriate generator winterization are currently in development or soon to be in effect.

47 North American Energy Standards Board Gas Electric Harmonization Forum Report ("NAESB Report"), July 28, 2023, at 1. https://www.naesb.org/pdf4/geh_final_report_072823.pdf .

2014 Polar Vortex Event

On January 5 through 8, 2014, "the Midwest, South Central, and East Coast regions of North America experienced a weather condition known as a polar vortex, where extreme cold weather conditions occurred in lower latitudes than normal, resulting in temperatures 20 to 30 [degrees] below average. Some areas faced days that were 35 [degrees] or more below their average temperatures. These temperatures resulted in record high electrical demand for these areas on January 6 and again on January 7, 2014."[48] Demand for natural gas also increased, and significant amounts of natural gas-fired generating units were unavailable because they did not have natural gas.[49] "By properly and appropriately communicating through the NERC [EEA][50] process using interruptible load, demand-side management tools, and voltage reduction, only one BA was required to shed firm load. The amount shed was less than 300 MW, representing less than 0.1 percent of the total load for the Eastern and ERCOT Interconnections."[51] The "lower temperatures had a drastic impact on load, with many of the Reliability Coordinators [e.g., MISO, PJM, TVA, VACAR-South, and Southeastern RC] reporting record or near-record winter peak demands. PJM exceeded its historic winter peak on both January 7 and January 8, 2014, and MISO reported that [it] exceeded [its] historic winter peak for three straight days (January 6–8, 2014)."[52]

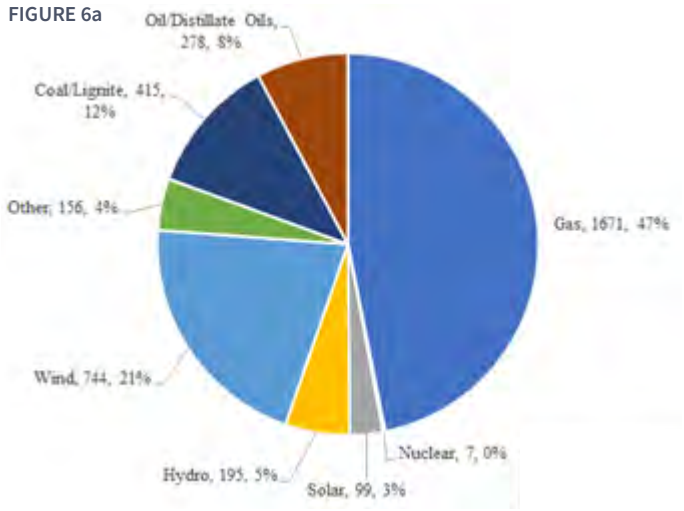
NERC staff reviewed and validated the Generating Availability Data Systems (GADS)[53] data covering the Polar Vortex event. Analysis of these data identified two principal causes of generating unit outages: curtailment or interruption of natural gas fuel supply and over 17,700 MW of lost generating capacity due to frozen equipment.[54] The majority of forced outages, 55 percent, were natural gas-fired generating units, although they only represented 40 percent of capacity in the Polar Vortex event area (Eastern and ERCOT Interconnections).[55] Although the Polar Vortex Review stated that "many generator outages" occurred as a result of entities exceeding the design basis of their plants, it did not quantify the percentage. The Review identified associations between temperature and increasing outages in most of the Regional Entity footprints.[56]

The Review's ten recommendations included the following: that the electric industry work with the gas industry "to allow generators to be able to secure firm supply and transportation at a reasonable rate;" to review and update generating units' weatherization plans; to implement periodic site reviews of generating units' winter preparedness; to reconsider forced outage rate assumptions in winter assessments, as well as assumptions about natural gas outage rates and heating oil replenishment; to limit planned outages during winter peak periods; to improve BAs' awareness of generating units' fuel status; to protect stored fuel against effects of cold weather; to review generating units' design basis and protect against outages that occur within design basis; and to prepare to apply for necessary environmental (or other) waivers during emergencies.

48 Polar Vortex Review at iii.
49 Id.
50 *See* note 21.
51 Polar Vortex Review at iii.
52 Polar Vortex Review at vii.
53 Generating Availability Data System (GADS) is a mandatory industry program for tracking information about outages of BES generating units. Generating Availability Data System (GADS) (nerc.com).
54 Polar Vortex Review at 2.
55 Polar Vortex Review at 13.
56 Polar Vortex Review at 4-12.

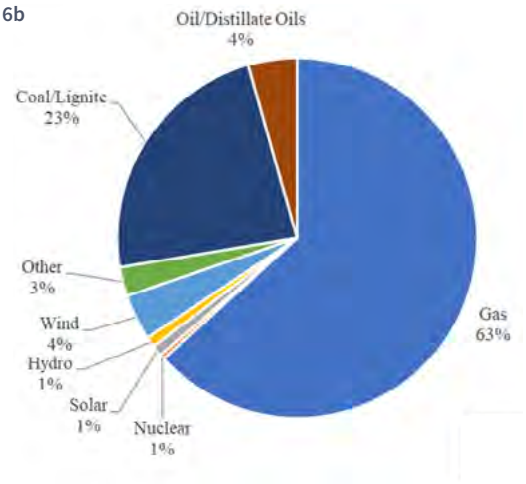
Figures 6a, 6b: Event Area Incremental Unplanned Generating Unit Outages, Derates and Failures to Start by Fuel Type: Percentages by Number of Outages, and Percentages by Unavailable MW[57]

FIGURE 6a



1,702 Generating Units 3,565 Outages/Derates

FIGURE 6b



1,702 Generating Units 3,565 Outages/Derates

57 Additional Figures of unplanned generation outages by other fuel types can be found in Appendix C: Additional Charts and Figures for Unplanned Generation Outages During Event.

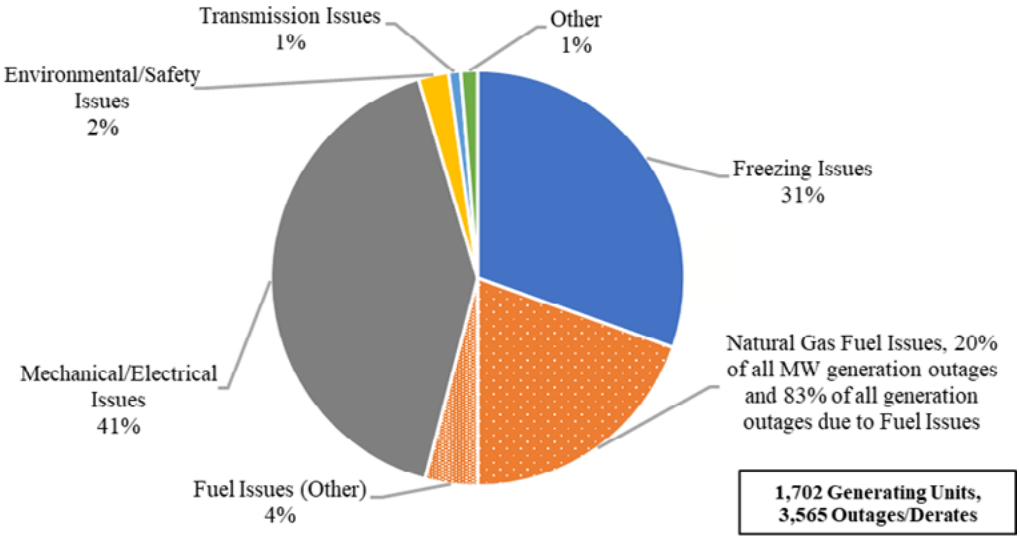
C. Key Findings and Causes

From December 21 to 26, 2022, in the Event Area, a total of 1,702 individual generating units—47 percent natural gas-fired, 21 percent wind, 12 percent coal, 3 percent solar, 0.4 percent nuclear, 17 percent other (oil, hydroelectric and biomass)—experienced 3,565 outages, derates, or failures to start (see Figures 6a & 6b, below).

Ninety-six percent of all outages, derates, and failures to start were attributed to three causes: Freezing Issues (31 percent), Fuel Issues (24 percent) and Mechanical/Electrical Issues (41 percent). Of those outages, derates, and failures to start, 55 percent were caused by either Freezing Issues or Fuel Issues, as shown in Figure 7 below. Natural Gas Fuel Issues[58] (a subset, but the majority, of Fuel Issues) were 20 percent of all causes, and issues with other fuels were four percent.

In addition to the outages, derates, and failures to start caused by Freezing Issues, those caused by Mechanical/Electrical Issues also indicated a clear pattern related to cold temperatures—as temperatures decreased, the number of generating units experiencing an outage, derate or failure to start due to Mechanical/Electrical Issues increased.

Figure 7: Incremental Unplanned Generating Unit MW Outages, Derates and Failures to Start, Total Event Area: by Cause



Prior to the Event, Generator Owners had ample reminders, guidance and opportunities to prepare for the extreme cold weather, and most did have plans in place. For example, FERC and NERC had provided

58 Natural Gas Fuel Issues include the combined effects of decreased natural gas production; cold weather impacts and mechanical problems at production, gathering, processing and pipeline facilities resulting in gas quality issues and low pipeline pressure; supply and transportation interruptions; curtailments and failure to comply with contractual obligations. Additionally, it includes shippers' inability to procure natural gas due to tight supply, prohibitive, scarcity-induced market prices, or mismatches between the timing of the natural gas and energy markets.

multiple prior recommendations and follow-up activities regarding steps for winter preparedness.[59] In addition, Generator Owners received annual reminders via Regional Entity workshops to prepare for winter (which provide detailed suggestions for how to protect generating units from freezing). Yet, despite these reminders, guidance, and their own preparation, over 75 percent of the generating unit failures caused by Freezing Issues[60] occurred at temperatures above the units' documented operating temperatures.[61] Over 150 blackstart-designated generating units,[62] totaling 19,000 MW, incurred outages during the Event, 119 of which were natural-gas-fueled generating units (accounting for just under 75 percent of all MW of blackstart-designated generation outages).

During the Event, natural gas production experienced its greatest decline since 2021's Winter Storm Uri, in which Texas production dropped by 70 percent. The Marcellus Shale[63] and Utica Shale[64] formations (combined, the Appalachia Region, which produced more natural gas than any other U.S. region in 2022) production dropped by 23 to 54 percent during the Event.[65] Wellhead freeze-offs, other natural gas supply chain equipment freezing and weather-related poor road conditions that prevented necessary maintenance were the top causes.

59 For examples of other activities to publicize the need for, and how, generators can protect their units from cold weather, *see* FERC, NERC and Regional Entities Technical Conference: Improving Winter-readiness of Generating Units; NERC Alerts I and II Cold Weather Preparations for Extreme Weather Events; Cold Weather Preparations for Extreme Weather Events II; NERC annual webinars on preparation for cold weather (https://www.nerc.com/pa/rrm/Pages/Webinars.aspx); NERC Compliance Monitoring and Enforcement Program practice guide (questions for BAs, RCs, and other entities for understanding their cold weather preparedness risk mitigation) https://www.nerc.com/pa/comp/guidance/CMEPPracticeGuidesDL/CMEP%20Practice%20Guide%20-%20Cold%20Weather%20Preparedness.pdf.

60 Includes unplanned outages, derates, and failures to start caused by Freezing Issues. This analysis is limited to generating units that provided outage data, ambient temperature data, and data concerning that units' operating parameters. Not all GOs provided data for each of these data sources in a manner and format which the Team was able to analyze.

61 GOs were given options for documenting their generating units' temperature limits in their data responses: design temperature, historical operating temperature, or current cold weather performance temperature determined by an engineering analysis. Many GOs provided the Team with more than one of these temperatures; if so, the Team used the highest of the temperatures to calculate the 75 percent figure. Using one of the lower temperatures provided for all GOs would have yielded a higher figure. The Team will use the phrase "documented operating temperatures" to refer to these temperatures.

62 Blackstart ("blackstart") refers to restarting the power grid after a major portion of the electrical network has been de-energized, and generators that have blackstart capability are those that can be started independently and without external power. *See* NERC Glossary of Terms for NERC definition of Blackstart Resource, and NERC Reliability Standard EOP-005-3 – System Restoration from Blackstart Resources.

63 The Marcellus Shale formation spreads across Pennsylvania, New York, West Virginia, Maryland, Tennessee, Kentucky, Ohio, and Virginia.

64 The Utica Shale formation covers parts of Pennsylvania, New York, West Virginia, Maryland, Tennessee, Kentucky, Ohio, New York, and Canada.

65 "In 2022, the Appalachia region produced more natural gas than any other U.S. region, accounting for 29 [percent] of U.S. gross natural gas withdrawals." U.S. Energy Information Administration - EIA - Independent Statistics and Analysis

D. Recommendations

In response to the continued failures of generating units due to Freezing Issues, the Team[66] urges prompt development and implementation of the remaining revisions to the Reliability Standards recommended by Key Recommendation 1 from the 2021 Report to strengthen generators' ability to maintain extreme cold weather performance. Additionally, the Team suggests robust monitoring of the implementation of currently-effective and approved cold weather Reliability Standards to determine if reliability gaps exist. The Team includes several recommendations to prevent generating unit freeze issues, one targeted at those units that failed above their designated operating limits, and three applicable to all units. Another recommendation suggests that Generation Owners communicate changes in their operating limits to the BA in real time. The Team also recommends a technical review of the individual causes of cold-related mechanical/electrical generation outages to reduce the frequency of these outages and inform whether additional Standards are needed. Finally, the Team recommends another blackstart study, like the one currently being conducted for the ERCOT Interconnection in response to Recommendation 26 from the 2021 Report, but focusing on the Eastern and Western Interconnections.

In response to the natural gas production, processing and pipeline issues, the Team recommends that Congress and state legislatures (or state regulatory entities that have jurisdiction over natural gas infrastructure reliability) take action to establish reliability rules for natural gas infrastructure necessary to support the grid and natural gas LDCs in three areas: cold weather preparedness/freeze protection; regional natural gas situational awareness, coordination and information sharing (similar to the grid's Reliability Coordinators); and the designation of critical natural gas infrastructure (for prioritization during load shed).

The Team makes several recommendations concerning natural gas-electric coordination, including consideration of whether to require a one-time report to the Commission from FERC-jurisdictional natural gas entities describing how they are assessing and responding to their vulnerabilities to extreme cold weather; a NAESB effort to enhance situational awareness through communication during extreme cold weather events (both among natural gas infrastructure entities, and with grid entities); and a study to analyze whether additional natural gas infrastructure, including interstate pipelines and storage, is needed to support the reliability of the electric grid and meet the needs of natural gas LDCs.

Finally, the Team recommends several potential improvements for grid operations, including Balancing Authorities improving their short-term load forecasts for extreme cold weather periods by implementing and sharing effective practices with peers for continuous improvement; Balancing Authorities assessing whether new or modified processes such as multi-day risk assessment or reliability commitments are needed to mitigate the risk of capacity shortages or other reliability issues during extreme cold weather events; resource planners and entities serving load sponsoring joint-regional reliability assessments of electric grid conditions that could occur during extreme cold weather; and a study to examine potential Eastern Interconnection stability risks on December 23 and 24 during periods of decreased frequency and low responsive reserves.

66 *See* note 1 for definition of the Team.

II. EVENT OVERVIEW AND RELEVANT BACKGROUND INFORMATION

A. Event Overview: Both the Electric Grid and the Natural Gas Pipeline System Experienced a Supply Shortage Event, Leaving Some System Operators with No Choice but to Take the Extreme Step of Shedding or Curtailing Firm Customers in Order to Maintain System Reliability

Both the electric grid and the interstate natural gas pipeline system must account for situations where there is too little supply to maintain system reliability. Insufficient supply can create the risk of dangerously low voltage on the grid or pressure on the pipelines, respectively. This event was a supply shortage event for both the electric grid and the natural gas pipeline system.

During the Event, natural gas supply shortages began with freezing issues and weather-related access issues associated with production facilities and equipment, which rippled throughout the natural gas infrastructure system. Natural gas pipelines faced decreased supply flowing into the pipelines at the same time that shippers requested increased volumes of gas, with some shippers taking volumes of gas in excess of their entitlement. The reduced supply relative to higher volumes of delivered gas (a situation known as a draft condition) resulted in lower line pressures and reduced line pack. Pipeline system operators faced not only draft conditions but also freezing issues that affected important equipment like compressor stations. While they deployed line pack and storage, and dispatched personnel to respond to these conditions, most pipelines also needed to issue critical notices and Operational Flow Orders (OFOs), and some issued force majeures (which curtail even firm transportation).[67] Eventually pressures on some pipelines reached reliability-threatening levels. Con Edison, which provides local distribution of natural gas to over a million customers in Manhattan, The Bronx, and portions of Queens and Westchester County, New York, established an internal Gas System Emergency to preserve its system reliability due to rapidly decreasing pipeline pressures at its citygate that were not recovering. Had pipeline pressures not recovered, Con Edison could have faced an unprecedented loss of its entire system that, in this worst case scenario, would have taken months to restore, even with mutual assistance. WE Energies, a local gas distribution utility in Wisconsin, had to resort to consumer appeals to drop thermostats to 60 degrees on the night of December 23 when one of the interstate pipelines it relied upon experienced an unexpected compressor outage and curtailed natural gas flow to WE Energies by 30 percent.[68]

On the electric grid, natural gas production declines reduced the supply available for natural gas-fired generating units. Many natural gas-fired generating units either do not contract for firm gas supply or transportation, or contract for only a portion of the firm supply or transportation needed to meet their winter peak needs.[69] They are then unable to obtain natural gas when natural gas supply and available pipeline capacity become scarce-to-unobtainable in extreme cold weather. On top of the natural gas-related fuel outages, the grid experienced

67 *See* p. 76 for sidebar on pipeline communications for explanations of these terms.

68 Karl Ebert, "*On a bitter cold night, We Energies begged customers to turn down their thermostats. How close did the natural gas supply system come to failure?*" Milwaukee Journal Sentinel, (Jan. 20, 2023), https://www.jsonline.com/story/money/business/energy/2023/01/20/what-caused-we-energies-natural-gas-crisis-on-dec-23/69785899007/.

69 *See* Figure 85 for contractual arrangements held by some of the GOs/GOPs in the Event.

generating unit outages, derates and failures to start due to Freezing Issues and Mechanical/Electrical Issues that were closely correlated with falling temperatures. Total unplanned coincident generating unit outages, derates and failures to start during the Event exceeded 90,000 MW, the most ever observed compared to other extreme cold weather events that impacted the U.S.

While interstate pipeline and electric grid operators used every tool (e.g., EEA 1 or 2 for the grid, OFOs for pipelines) to avoid disruptions in service, some operators were forced to make difficult decisions such as curtailing firm natural gas customers or shedding firm electricity customers, to allow the system to recover from reliability-threatening conditions rather than deteriorate into an uncontrolled loss of an entire pipeline or the electric grid.

The coldest areas in Winter Storm Elliott did not deviate from normal lows as much as the coldest areas in 2021's Winter Storm Uri (comparing the NOAA-produced graphics of deviation from normal lows). In Uri, the coldest areas were between 40 and 50 degrees below the normal low, while in Elliott the coldest areas, on the peaks of the Appalachian Mountains, were between 30 and 35 degrees below the normal low. However, temperature alone is not the only factor in determining the extent to which extreme cold weather will wreak havoc on generating units and natural gas infrastructure. Wind and precipitation exacerbate the effects of temperature.[70] In the Event, TVA noted that rain followed by extreme cold weather and wind created an environment that was beyond the design basis of some TVA generating sites. Freezing rain can coat wind turbine blades, rendering them out of service until the icing is removed, while snow causes the largest performance drops at solar facilities.[71] Rain can also soak insulation, limiting or eliminating its ability to protect against cold. Another factor, which played a strong role in the Event, is how quickly the winter temperatures dropped. An extremely rapid drop (for example, temperatures in Charleston, West Virginia, ranged from 45 degrees at 2:43 a.m. to 3 degrees[72] at 8:43 a.m., a drop of 42 degrees in six hours), increases system load as it challenges the ability of home heating systems to maintain consistent temperatures.

The Event had the largest footprint of any examined in a joint FERC-NERC-Regional Entity inquiry. As shown in Figure 8, below, the extreme cold weather covered most of the eastern half of the lower 48 United States, except for some of Florida. The Team focused on affected entities that either shed firm load or lost larger percentages of their generating unit capacity. All were located within the Eastern Interconnection and had multiple tie lines to other entities within the Eastern Interconnection.

Entities that were more severely affected (Core Entities)[73] included PJM, (represented by the blue box below in Figure 9); TVA and LG&E/KU BAs, within TVA's Reliability Coordinator footprint (represented by red and white striped boxes); Southern (represented by an aqua box); and DEP, DEC/VACAR-South RC, DESC and Santee Cooper, represented by pink boxes). Within the Event Area, the Team also examined MISO, SPP, ISO New England and NYISO (collectively represented by gold boxes) to better understand how their generating unit outages and flows exchanged with Core Entities impacted Event outcomes.

70 The effects of a lower dry bulb temperature is equivalent to those of a higher dry bulb temperature with high winds or associated precipitation.

71 Nicole D. Jackson & Thushara Gunda, Evaluation of extreme weather impacts on utility-scale photovoltaic plant performance in the United States, 302, Applied Energy, 1:7 (2021) Sandia National Labs.

72 The Report includes temperature references only in Fahrenheit.

73 See note 35 for definition of Core Event Area, which includes definition of Core Entities.

B. Background on Affected Systems and Entities

1. RELIABILITY ROLES

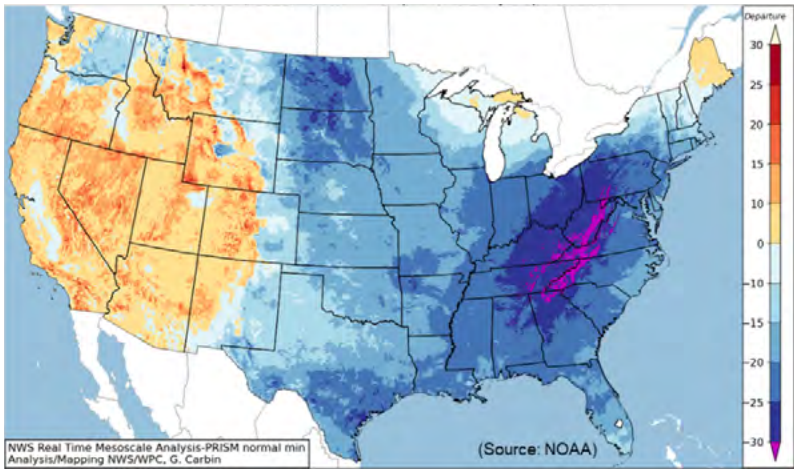
NERC categorizes the entities responsible for planning and operating the BES in a reliable manner into multiple categories of functional entity types. The NERC roles most relevant to the Event are Reliability Coordinators (RCs), Balancing Authorities (BAs), Generator Owners (GOs), Generator Operators (GOPs), Transmission Owners (TOs), Transmission Operators (TOPs), Planning Authority/Planning Coordinators (PA/PCs), and Transmission Planners (TPs). Several of the Core Entities (also referred to as "Core BAs"), especially PJM, TVA, Southern, DEC/VACAR-South RC, and DESC, served multiple reliability roles during the Event.

2. INTERCONNECTIONS BETWEEN AFFECTED ENTITIES AND OTHER PARTS OF THE ELECTRIC GRID

In North America, there are four separate power grids or "interconnections." The Eastern interconnection includes the eastern two-thirds of the continental United States and Canada from Saskatchewan east to the Maritime Provinces (see Figure 10, below), and is electrically independent from the other interconnections.

The Eastern Interconnection is the largest of the four interconnections, and by itself has been called the largest machine in the world.[74] The Eastern Interconnection is electrically connected to the Western, ERCOT and Quebec Interconnections by means of Direct Current (DC) asynchronous transmission tie lines.[75] Within each interconnection, power generally flows without barriers (subject to operational limits) from one utility's system to another across the entire grid via alternating current (AC) tie lines. A significant enough imbalance of generation and demand can cause instability of one utility's system to affect the stability of all utility systems operating in that interconnection.[76]

Figure 8: Extreme Cold Weather Conditions – December 24, 2022

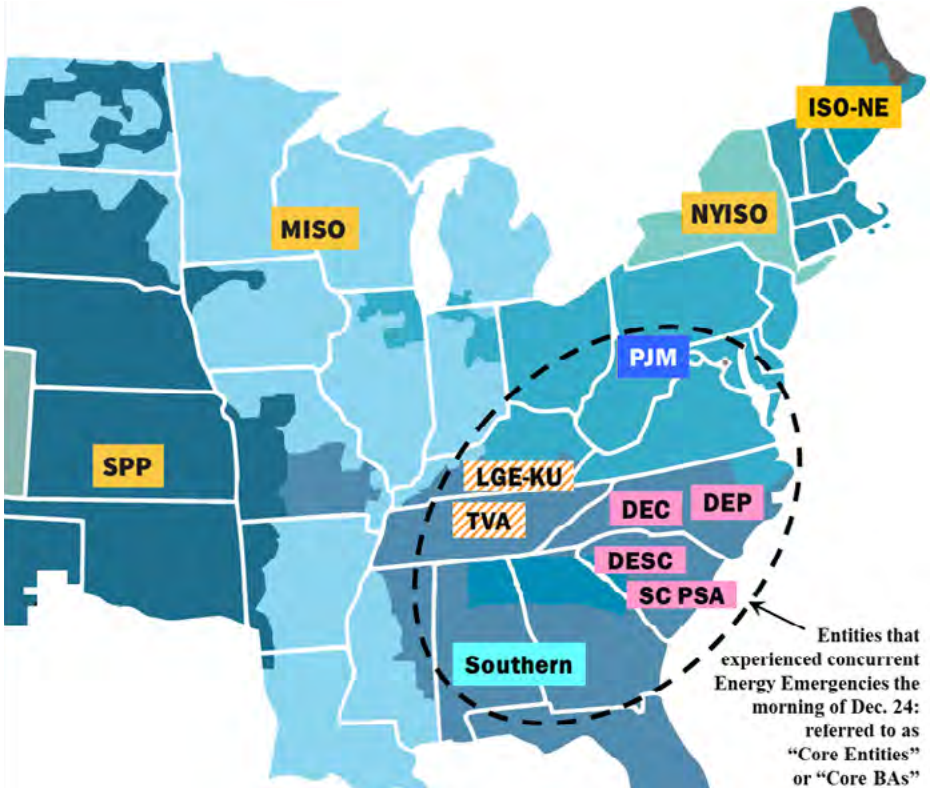


74 "Multi Dimensional Issues in International Electric Power Grid Interconnections," 15 (2006), https://www.un.org/esa/sustdev/publications/energy/interconnections.pdf.

75 For DC transmission lines, the flow of power is controlled (i.e., scheduled), rather than flowing continuously as on synchronous ties.

76 *See* generally, U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations, 5-10 (April 2004), https://www.ferc.gov/sites/default/files/2020-05/ch1-3_0.pdf.

Figure 9: Bulk Electric System Map of Affected Entities



3. DESCRIPTION OF U.S. BES ENTITIES IN THE EASTERN INTERCONNECTION AFFECTED BY WINTER STORM ELLIOTT

a. PJM and other RTOs/ISOs in the Eastern Interconnection[77]

PJM (Core Entity). PJM is a regional transmission organization (RTO) covering 13 states (Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia)[78] and Washington, DC for a total of 368,906 square miles.[79] PJM is NERC-registered as a BA, RC, PA/PC, and TOP, and in the latter capacity, operates 88,115 miles of transmission lines.[80] It monitors over 1,400 generating units. In 2022, PJM obtained energy from 40 percent gas generation, 20 percent coal, 32.3 percent nuclear, 1.9 percent hydroelectric, 3.7 percent wind, and 2.2 percent other (all calculated on a MWh basis). Its total installed capacity at the end of December 2022 was 183,385 MW.[81] PJM has historically been a summer-peaking region, and its all-time peak load was 165,563 MW during the summer of 2006. PJM operates an energy and ancillary services market that includes both day-ahead and real-time markets.

MISO. MISO is an RTO that operates the grid across 15 states and the Canadian province of Manitoba, and

77 While both New York ISO (NYISO) and ISO-NE incurred significant distribution power outages from Winter Storm Elliott, both experienced less-severe BES impacts during the Event. These ISOs are discussed in Section III of the Report.

78 https://www.pjm.com/about-pjm/who-we-are.

79 https://www.pjm.com/about-pjm, https://services.pjm.com/annualreport2022/.

80 https://learn.pjm.com/-/media/about-pjm/newsroom/fact-sheets/pjm-at-a-glance.ashx.

81 http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2022/2022-som-pjm-press-briefing.pdf.

serves as a BA and RC, among other reliability roles.[82] MISO operates 75,000 miles of transmission lines, is a summer-peaking region, and experienced its highest peak load to date, 130,917 MW, on July 20, 2011. MISO's generating capacity is 198,933 MW, comprised of 42 percent natural gas-fired generation, 29 percent coal, 19 percent renewables and eight percent nuclear generation. Currently, MISO operates one of the largest energy and operating reserve markets, with annual gross transactions of $22 billion, as well as an ancillary services market, and includes both day-ahead and real-time markets.

SPP. SPP is an RTO and serves as a BA and RC, among other reliability roles. It operates a 552,885-square-mile area that includes all or portions of 14 states, including: Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas and Wyoming.[83] SPP operates 70,025 miles of transmission lines. It is a summer-peaking region and although it experienced its highest peak load of 56,184 MW on August 21, 2023, it experienced a new all-time winter peak load of 47,157 MW during Winter Storm Elliott. SPP's generating fleet is 38.5 percent (nameplate) natural gas, 29 percent wind, and 24.3 percent coal. However, coal accounts for the majority of the generated energy with 38.6 percent of the total, while wind and natural gas produce about 29.5 percent and 22.7 percent respectively.[84] SPP operates an energy and ancillary services market that includes both day-ahead and real-time markets.

b. Grid Operators in the Southeast U.S.

TVA (Core Entity). TVA is a federally-owned electric utility corporation, the largest public power provider in the U.S., and serves as a BA, RC, GO, GOP, TO and TOP, among others. TVA's service area covers most of Tennessee, portions of Alabama, Mississippi, and Kentucky, and small areas of Georgia, North Carolina and Virginia. TVA owns and operates approximately 16,200 miles of transmission lines and serves 12 million customers. TVA's generation fleet consists of 33 percent natural gas, 39 percent nuclear, 14 percent coal, 10 percent hydro, and four percent wind and solar. TVA is a dual (both summer and winter) peaking region and set a new record winter peak of 33,425 MW during the Event on December 23, 2022.

LG&E/KU (Core Entity). LG&E and KU are subsidiaries of PPL Corporation. They are regulated public utilities that serve more than 1 million electric customers combined. LG&E/KU operate their combined transmission systems as a joint BA Area, PC Area, and TOP Area. LG&E/KU are also registered as a GO, GOP, TSP, TP, and TO. TVA serves as LG&E/KU's RC. LG&E serves approximately 333,000 natural gas and 429,000 electric customers in Louisville and 16 surrounding counties.[85] KU serves approximately 566,000 electric customers in 77 Kentucky counties and five counties in Virginia operating as Old Dominion Power Company.[86] Together, the companies own approximately 5,400 miles of electric transmission lines.[87] Their combined generation fleet includes 37.5 percent natural gas, 59.6 percent coal, and 2.9 percent hydro and other. LG&E/KU is dual peaking, and its all-time winter peak BA load was 7,336 MW on January 6, 2014.

DEP and DEC (both Core Entities). DEP and DEC are subsidiaries of Duke Energy. DEP operates as a BA, GO, GOP, PA/PC, TO, and TOP. DEC is the agent for the VACAR-South RC, and operates as a BA, GO, GOP, PA/PC, TO, and TOP.[88] DEP has 16,390 megawatts of generation

82 MISO Corporate Fact Sheet, https://www.misoenergy.org/about/media-center/corporate-fact-sheet/.
83 SPP Fact Sheet https://www.spp.org/about-us/fast-facts/.
84 *Id.*
85 About LG&E and KU | LG&E and KU (lge-ku.com); https://lgeku.com/investments#:~:text=The%20same%20type%20of%20detailed,gas%20storage%20fields%20that%20enable .
86 https://lge-ku.com/about.
87 https://lge-ku.com/about.
88 https://www.nerc.com/comm/OC/Operating%20Reliability%20Subcommittee%20ORS%202013/ORS_Presentation_Nov_6-7_2019.pdf pg 15

capacity within its footprint, 1.7 million residential, commercial and industrial electricity customers across a 29,000-square-mile service area in North Carolina and South Carolina, and operates 6,300 miles of transmission lines. Generation within its footprint includes 38.1 percent natural gas, 19.4 percent coal, 22.8 percent nuclear, 1.5 percent hydro and other. DEC has 25,848 megawatts of generation capacity within its footprint (34.2 percent natural gas, 23.7 percent coal, 28.5 percent nuclear, 13.2 percent hydro and other), 2.8 million residential, commercial and industrial electricity customers across a 24,000-square-mile service area in North Carolina and South Carolina,[89] and operates 13,000 miles of transmission lines. DEP's and DEC's record winter peak loads were 15,569 MW and 21,620 MW, respectively.

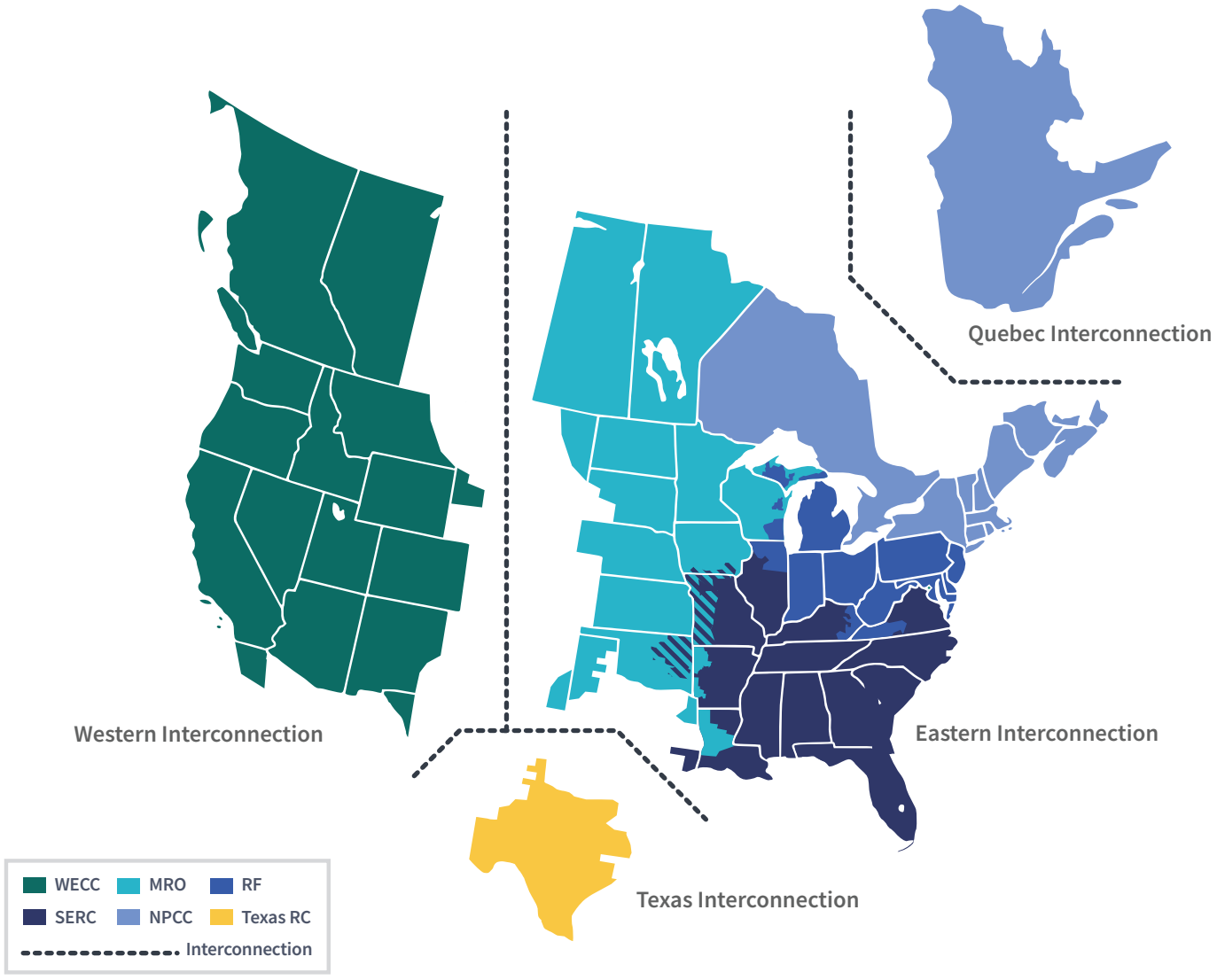
DESC (Core Entity). DESC (formerly known as South Carolina Electric & Gas Company) is a vertically integrated electric utility for the central, southern, and southwestern portions of South Carolina. DESC serves as a BA, GO, GOP, PA/PC, TO, and TOP. VACAR-South is its RC. DESC also purchases and distributes natural gas.[90] DESC's generating fleet is 40 percent natural gas,[91] 25 percent coal, 14 percent solar,[92] and 9 percent nuclear energy for a total net winter capacity of 6,821 MW. DESC is dual peaking, and its record winter peak load was 4,970 MW.

Santee Cooper (Core Entity). Santee Cooper (shown as "SC PSA" in Figures 1 and 9 above) is South Carolina's state-owned electric utility. It provides power to approximately two million people,[93] and operates as a BA, GO, GOP, PA/PC, TO, and TOP. VACAR-South is its RC. Santee Cooper sells electricity to Central Electric Power Cooperative, a wholesale power provider, which in turn provides power to South Carolina's 20 electric cooperatives.[94] It also provides power to the cities of Bamber and Georgetown, 27 large industrial customers including Joint Base Charleston, the Alabama Municipal Electric Authority, and the 10 member cities that form the Piedmont Municipal Power Agency.[95] Santee Cooper schedules power over 5,223 miles of transmission lines.[96] Its generation consists of 66.5 percent coal, 22.0 percent natural gas, 6.1 percent nuclear, 2.7 percent hydro, and 2.8 percent other. Santee Cooper is a winter-peaking region, and its highest winter peak demand was 5,342 MW in 2022.

Southern (Core Entity). Southern provides energy to nine million customers through its family of companies, including Alabama Power, Southern Power, Georgia Power, and Mississippi Power.[97] Southern also serves as a BA, PA/PC, and TOP, among others, and its RC is Southeastern RC.[98] Southern has electric operating companies in three states and natural gas distribution companies in four.[99] The Southern BA Area had 57,895 MW of projected generating capacity prior to Winter Storm Elliott and more than 27,000 miles of transmission lines.[100] The Southern BA Area generating fleet consisted of 53.5 percent natural gas, 20.3 percent coal, 11.5 percent nuclear, 8.7 percent hydro, 5.3 percent solar and wind, and 0.7 percent other. The Southern BA footprint is

89 https://p-cd.duke-energy.com/-/media/pdfs/our-company/duke-energy-fast-facts.pdf?rev=77d14a34d96f449493f89595285d4d57.
90 https://www.dominionenergy.com/projects-and-facilities/natural-gas-facilities/south-carolina-natural-plants.
91 Thirty of the 40 percent of DESC's natural gas generating fleet is dual fuel.
92 According to DESC, "Most of the time, DESC gets close to zero percent solar at time of morning winter peak loads since they occur before the sun rises."
93 https://www.santeecooper.com/about/.
94 https://www.flipsnack.com/santeecooper/fingertip-facts-2022/full-view.html.
95 https://www.flipsnack.com/santeecooper/fingertip-facts-2022/full-view.html.
96 https://www.flipsnack.com/santeecooper/fingertip-facts-2022/full-view.html.
97 https://www.southerncompany.com/about/our-companies.html#:~:text=We%20support%209%20million%20customers,wireless%20communications%20across%20the%20country.
98 SERC recognizes Southern Company Services as the Reliability Coordinator for the Southeastern RC area.
99 https://www.southerncompany.com/about/our-companies.html#:~:text=We%20support%209%20million%20customers,wireless%20communications%20across%20the%20country.
100 https://www.southerncompany.com/about/our-business.html#:~:text=Southern%20Company%20operations%20has%20responsibility,a%20safe%20and%20reliable%20grid.

Figure 10: Electric Interconnections Map



generally dual peaking (summer and winter), with its all-time peak load being 48,008 MW.[101] Southern set a new December peak record during the Event of 45,153 MW on December 24.[102]

Figure 11, below, lists the capacity of BES generation resources for the Core Entities by fuel type, at the time of the Event. Natural gas-fueled generation comprised the largest percentage (41.90 percent) of generation across the core entities, followed by coal-fired generation at 24.19 percent. Renewable BES generation capacity was relatively low (1.94 percent solar and 1.12 percent wind, respectively) in the Core Event Area.

101 https://www.southerncompany.com/content/dam/southerncompany/sustainability/pdfs/2022-Year-in-Review.pdf.

102 https://www.southerncompany.com/content/dam/southerncompany/sustainability/pdfs/2022-Year-in-Review.pdf. For the Southern Company BA area, its all-time winter peak load was 45,887 MW.

Figure 11: Total Installed Net Capacity of BES Generation Resources Located within Core Entity Footprints During Event, and Resource Fuel Type Composition for Combined Core Entity Footprints

Core Entity Footprint	Capacity
	(MW)
DEC	25,848
DEP	16,390
DESC	6,821
LG&E/KU	7,973
PJM	186,270
Santee Cooper	5,237
Southern	57,895
TVA	36,456
TOTAL MW	**342,890**

Fuel Type	Combined Core Entity Footprints	
	(MW)	(Percent)
Coal	82,954	24.19%
Hydro*	34,455	10.05 %
Natural Gas	143,658	**41.90 %**
Nuclear	59,963	17.49 %
Solar	6,653	1.94 %
Wind	3,857	1.12 %
Other	11,350	3.31 %
TOTAL MW	**342,890**	**100%**

*Includes Pumped Storage

c. Tie Lines Between Entities

The affected entities, each operating as BAs, have AC transmission tie lines which connect one BA to another, and enable power transfers to be routinely scheduled between them (resulting in power imports and exports) when generation reserves in the exporting BA and available transmission capacity are sufficient to accommodate the power transfers. All BAs in the Eastern Interconnection have multiple tie lines connecting them to neighboring BAs (BAs that are directly connected via tie lines are often referred to as "adjacent BAs").

In general, there is an extensive network of transmission tie lines between the Core BAs in the Eastern Interconnection, which under normal conditions allow for significant imports and exports among them. Figure 12, below shows the number of tie lines, by voltage level, between the Core BAs. ISO-NE, NYISO, MISO, and SPP also have tie lines with Canadian BES BAs (not shown on Figure 12).

Figure 12: Total Number of AC Transmission Tie lines, Number of Tie Lines between Adjacent Core BAs, and with other BAs Affected by Elliott, by Voltage Level

	DEC			DEP			DESC			LG&E/KU			PJM			Santee Cooper			Southern			TVA		
Totals:	29			41			31			85			201			35			55			61		
Voltage Level	DEC - DESC	DEC - PJM	DEC - Santee Cooper	DEC - Southern	DEP - DEC	DEP - PJM	DEP - DESC	DEP - Santee Cooper	DESC - Santee Cooper	DESC - Southern	LG&E/KU - MISO	LG&E/KU - PJM	PJM - MISO	PJM - NYISO	Santee Cooper - Southern	Southern - Florida BAs	Southern - MISO	TVA - LG&E\KU	TVA - MISO	TVA - PJM	TVA - Southern	TVA - DEC	TVA - DEP	TVA - AECI
<100 kV	---	---	---	---	---	---	---	---	---	---	1	33	4	7	---	2	0	2	1	1	---	---	---	---
100 to 150 kV	2	1	---	---	3	4	1	2	10	3	7	17	33	6	---	12	1	---	1	2	1	---	---	---
150 to 300 kV	2	---	4	---	11	7	2	8	9	2	5	6	---	4	2	10	7	4	15	7	7	2	1	1
300 kV and Higher	---	1	---	1	1	1	---	---	---	---	7	2	51	11	---	2	1	1	7	3	4	1	---	---
TOTAL	4	2	4	1	15	12	3	10	19	5	20	58	88	28	2	26	9	7	24	13	12	3	1	1

C. Background on Preparation for 2022-2023 Winter Peak Operations

1. SEASONAL PROJECTIONS AND ASSESSMENTS BY AFFECTED GRID ENTITIES

In general, BAs and RCs (which included both RTO and non-RTO entities) performed 2022-2023 winter season demand forecasts and projections of adequacy for both generation resources and transmission performance for their respective footprints.

a. Season Peak Load Forecasts

Figure 13, below, provides a summary of peak load forecasts that were made by the Core BAs in advance of the 2022-2023 winter season (typically developed by entities during the third calendar quarter in advance of the subsequent winter). Figure 13 compares the forecast peak loads against the actual peak loads that occurred within each Core BA footprint during the Event (as well as, where available, against the estimated peak if firm load shed or demand response had not reduced the actual peak load).

Figure 13: Winter 2022-2023 Season BA Peak Load Forecasts and Actual Hourly Winter Peak Loads for the Core Event Area (in MW)

		DEC	DEP	DESC	LG&E/KU	PJM	Santee Cooper	Southern	TVA
Previous All-Time Hourly Winter Peak		21,620	15,569	4,970	7,336	143,225	5,869*	45,887	33,352
Date of Occurrence		01/05/18	02/20/15	02/20/15	01/06/14	02/20/15	02/20/15	01/07/14	01/24/14
Winter 2022-2023 50/50 Forecast		20,246	14,454	4,169	6,453	132,980	5,481	41,300	30,295
Winter 2022-2023 90/10 Forecast		22,147	16,911	4,726	7,051	143,782	6,000	45,462	34,363
December 2022 Actual Hourly Peak		20,568	13,819	4,678	6,891	134,189	5,342	45,153	33,427
Date		12/24/22	12/24/22	12/24/22	12/23/22	12/23/22	12/24/24	12/24/22	12/23/22
December 2022 Estimated Peak without Load Management		21,800	14,800	N/A	6,986	134,951	5,900	46,000	35,000
Percent 2022 Actual Peak was Above Forecasts:	50/50	1.59%	-4.39%	12.21%	6.79%	0.91%	-2.54%	9.33%	10.34%
	90/10	-7.13%	-18.28%	-1.02%	-2.27%	-6.67%	-10.97%	-0.68%	-2.72%
Percent 2022 Estimated Peak was Above Forecasts:	50/50	7.68%	2.39%	N/A	8.26%	1.48%	7.64%	11.38%	15.53%
	90/10	-1.57%	-12.48%	N/A	-0.92%	-6.14%	-1.67%	1.18%	1.85%

(a) DEC, DEP values listed for 90/10 forecasts were projected super peak loads, included "Super Peak" study as part of DEP and DEC winter 2022-2023 season transmission capability assessment. Super Peak values range from 9 (DEC) to 17 percent (DEP) to 17 percent (DEP) above 50/50 forecasts.

(b) DESC developed monthly 50/50 and extreme weather demand risk peak values. Jan-2023 forecasts were 50/50, 4,902 MW; extreme, 5,459 MW.

(c) PJM: previous All-Time Hourly Winter Peak value accounts for allocated 500 kV transmission losses. Winter 2022-2023 50/50 Forecast value represents the coincident peak 50/50 forecast and accounts for allocated 500 kV transmission losses (PJM uses the non-coincident peak 50/50 forecast (136,867 MW for Winter 2022-2023, not listed above) in its Operations Assessment Task Force seasonal studies). Winter 2022-2023 90/10 Forecastvalue accounts for allocated 500 kV transmission losses. 2022 Actual Hourly Peak and Estimated Hourly Peak without Load Management values account for allocated 500 kV transmission losses, and differ from peaks PJM reported elese where (135, 296) MW for actual and 136,010 MW for estimated peak w/o load management) due to a slight difference in the way load is defined for the long-term and short-term forecasting applications.

(d) *Santee Cooper 2015 / previous all-time winter peak load included load that is no longer served by Santee Cooper.

(e) Southern developed an extreme peak value based on statistical analysis.

Most of the BAs' actual winter peak loads during Winter Storm Elliott's extreme cold weather fell between their winter 2022-2023 50/50 and their 90/10 (or extreme forecast) winter season forecast peak loads.[103] A few BAs, such as TVA and Southern, would have exceeded both their 50/50 and 90/10 forecast peaks had they not implemented load management (Southern) or firm load reduction (TVA). Both BAs commented that winter peak load conditions do not exhibit a saturation point like summer peak air-conditioning-driven loads do, because electric heating (auxiliary backup heating for heat pumps, electric strip heating and electric space heaters) increases winter peak load in a non-linear manner as temperatures decrease.[104]

b. Capacity/Resource Reserves Projections

The Core BAs performed seasonal resource assessments in advance of the 2022/2023 winter to determine available generation reserves during winter peak conditions. The assessments included forecast peak loads, generation capacity, and projected reserves. Most of the Core BAs performed their respective winter season assessments assuming a 50/50 load forecast, although LG&E/KU's winter assessment assumed a 90/10 load forecast.[105] The paragraphs below summarize each BA's respective assessment.

Figure 14, below, depicts the winter 2022-2023 seasonal resource assessments for the Core BAs to meet their respective 50/50 and 90/10 forecast peak loads.

Figure 14: 2022-2023 Winter Season Resource Assessment Reserve Margins - Core BAs

		Without Demand Response		With Demand Response	
Balancing Authority	**NERC Region/Area**	50/50 Forecast Winter Peak Load (Percent)	90/10 Forecast Winter Peak Load (Percent)	50/50 Forecast Winter Peak Load (Percent)	90/10 Forecast Winter Peak Load (Percent)
DEC	SERC East	21.1	10.7	23.5	12.9
DEP	SERC East	9.0	-6.8	10.6	-5.5

103 A 50/50 peak load forecast is based on a 50 percent chance that the actual system peak load will exceed the forecast value, while a 90/10 peak load forecast is based on a 10 percent chance that the actual system peak load will exceed the forecast value.

104 *See* Recommendation 16 and Figure 108 from the 2021 Report, which shows how home heating demand due to electric auxiliary heating increases from two to four times once temperatures drop below 14 degrees (as compared to the demand at 32 degrees).

105 For more about how BAs conduct these assessments, *see* page 30 of the 2021 Report.

		Without Demand Response		With Demand Response	
Balancing Authority	**NERC Region/Area**	50/50 Forecast Winter Peak Load (Percent)	90/10 Forecast Winter Peak Load (Percent)	50/50 Forecast Winter Peak Load (Percent)	90/10 Forecast Winter Peak Load (Percent)
DESC	SERC East	18.7	6.6	23.5	10.9
LG&E/KU	SERC Central	15.1	5.4	15.1	5.4
PJM	RF/PJM	14.9	9.4	20.5	14.7
Santee Cooper	SERC East	-4.1	-12.4	7.3	-2.0
Southern	SERC Southeast	30.2	18.3	30.2	18.3
TVA	SERC Central	9.2	-3.7	14.6	1.0

DESC. DESC performed a Winter 2022/2023 resource assessment assuming a 50/50 load forecast. Based on its winter assessment, DESC believed that it could meet its projected winter peak demand of 4,902 MW with available generation and imports (based on normal weather conditions). DESC's extreme winter forecast[106] was 5,459 MW, higher than its previous all-time winter peak demand record of 4,970 MW, set in 2015. To meet that extreme peak demand, DESC projected a seasonal resource capacity of 5,819 MW, once 1,147 MW of planned and forced outages were deducted from available resources. This resulted in estimated reserves of 917 MW assuming the 50/50 load forecast and 360 MW for an extreme weather demand risk scenario.

Duke/DEC and DEP. Based on its winter resource reserves projection, Duke believed that it could meet its projected winter peak demand of 20,246 MW for DEC and 14,454 MW for DEP, for a combined load of 34,700 MW, with available generation and imports (based on normal weather conditions). To meet the projected winter demand, DEC projected a resource capacity of 24,510 MW, once 1,338 MW of planned and forced outages were deducted from available resources. DEP projected a resource capacity of 15,754 MW, once 636 MW of planned and forced outages were deducted from available resources. Duke assumed a forced outage rate of 2.5 percent based on recent historical performance. Duke adjusts reserves by third party imports/exports, projected demand response and units in extended reserve shutdown. This resulted in estimated reserves of 2,246 MW for DEC and 1,648 MW for DEP for the 50/50 load forecast.[107]

Duke's extreme winter forecast was 22,147 MW for DEC and 16,911 MW for DEP (39,058 MW combined), which was higher than its previous all-time winter peak demand record of 21,620 MW, set on January 5, 2018 for DEC and 15,569 MW, set on February 20, 2015 for DEP. Duke performed this super peak study to determine potential transfer capability limitations. The DEC transmission system would be capable of serving load of 24,457 MW before seeing any significant issues. The DEP transmission system would be capable of serving load of 17,491 MW before seeing any significant issues.

Santee Cooper. Santee Cooper performed a Winter 2022/2023 resource assessment assuming a 50/50 load forecast. Santee Cooper's winter load forecast is prepared using 20 years of monthly peak demand and energy usage each year around April. This forecast is composed of several component forecasts, including forecasts for different customer classes. Based on its winter

106 DESC uses a statistical regression technique to quantify an extreme winter weather demand level, based on its historically coldest winter days.

107 DEC and DEP also explained that there are no additional sub-areas, regions, or load pockets within the DEC and DEP BA areas where reserves are monitored to ensure sufficient resource reserves and/or deliverability of reserves for the regions or sub-areas.

assessment, Santee Cooper believed that it could meet its projected winter peak demand of 5,481 MW with available generation and imports (based on normal weather conditions).[108] Santee Cooper's extreme (i.e., 90/10) winter forecast was 6,000 MW, slightly higher than its previous all-time winter peak demand record of 5,869 MW, set on February 20, 2015.[109] To meet that extreme peak demand, Santee Cooper projected resource capacity of 5,237 MW and 626 MW of demand response. Without demand response, Santee Cooper projected a resource deficiency of up to 743 MW to meet its extreme load forecast of 6,000 MW. Santee Cooper relied on the Carolinas Reserve Sharing Group to recover from typical single-contingency outages of generating units and relied on import power purchases as needed for other scenarios such as multi-unit outage conditions.

LG&E/KU. LG&E/KU performed its Winter 2022/2023 resource assessment using the 90/10 load forecasts provided by the four load-serving entities in the LG&E/KU BA area: (1) LG&E/KU; (2) Owensboro Municipal Utilities; (3) Kentucky Municipal Power Agency; and (4) Kentucky Municipal Energy Agency. Although LG&E/KU used the 90/10 load forecast for their winter assessment, LG&E/KU also performed a 50/50 load forecast using the forecasts provided by the four load-serving entities (LSEs) in the BA area.[110] Based on the winter assessment, LG&E/KU believed that it could meet its projected winter peak demand of 6,453 MW with available generation and imports (based on normal weather conditions). LG&E/KU's extreme winter forecast demand was 7,051 MW. To meet that extreme peak demand, LG&E/KU projected resource capacity of 7,430 MW, assuming a 3.66 percent forced outage rate for coal units and 6.36 percent forced outage rate for natural gas units. LG&E/KU's assessment also considered multiple contingencies (e.g., analysis required in Reliability Standard TPL-001-5.1). This resulted in estimated reserves of 977 MW assuming the 50/50 load forecast and 379 MW for the 90/10 extreme load scenario.

TVA. TVA performed a Winter 2022/2023 resource assessment assuming a 50/50 load forecast. TVA uses 24 hourly regression models trained over the prior three years to estimate response of load to temperature (i.e., the corresponding MW increase from a one-degree increase or decrease of temperature). TVA's models use calendar factor variables (e.g., holidays, day of week, month, and year), seasonal weighted aggregate dry bulb temperatures based on the five largest cities in the TVA region,[111] and a 72-hour weighted average of the dry bulb temperature, where the more recent observations are more heavily weighted to estimate the impacts of thermal buildup. TVA uses these models to estimate load for its hourly temperature history (going back to 1960) as if the load had occurred with the current system size, in order to ensure a wide sample of load and temperature values. TVA uses the estimated loads to build a probability distribution to mitigate issues with a regression model. The models assume that the most extreme winter weather will occur in January and assume that the prior three years of hourly temperatures approximate current temperature response.

Based on its winter assessment, TVA believed that it could meet its projected winter peak demand of 30,295 MW with available generation and imports (based on normal weather conditions). TVA's extreme winter forecast was 34,363 MW, slightly higher than its previous all-time winter peak demand record of 33,352 MW, set on January 24, 2014. To meet that extreme peak demand, TVA projected resource capacity of 33,079 MW, once 577 MW of planned and 2,800 MW of unplanned outages were deducted from available resources. This resulted in estimated reserves of 2,784 MW for the 50/50 load forecast and 1,284 MW deficiency for the 90/10 extreme load scenario.

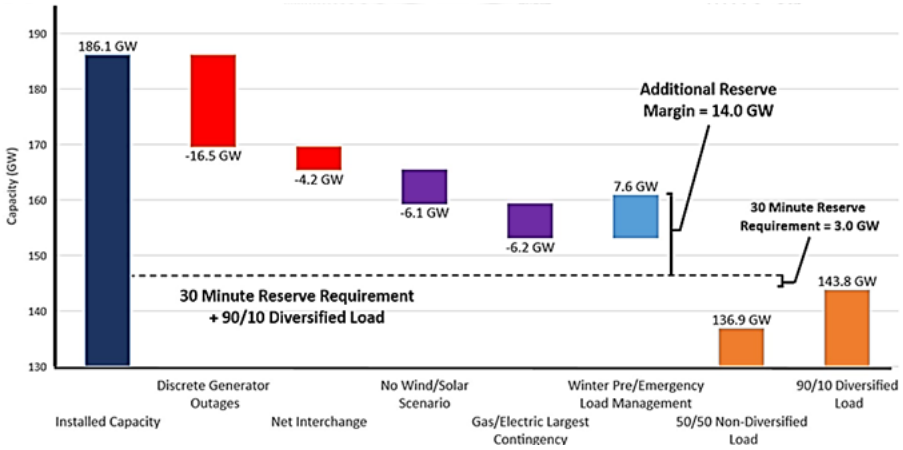
108 Based on its 50/50 forecast reserve margin without demand response, magnitude of imports to meet load and maintain operating reserves without deployment of demand response would have been in the range of 350-400 MW.

109 A portion of the load Santee Cooper was serving on February 20, 2015 is no longer served by Santee Cooper.

110 According to LG&E/KU, "[t]he [LG&E/KU] LSE forecasts the 50/50 winter peak load using the average temperature on the peak day over the last 20 years. To assess generation reliability and develop extreme weather load scenarios, the [LG&E/KU] LSE develops hourly demand forecasts based on the actual weather in each year since 1973. Degree days are the primary variable used to develop these forecasts."

111 I.e., Huntsville, Alabama; Memphis, Tennessee; Nashville, Tennessee; Chattanooga, Tennessee; and Knoxville, Tennessee.

Figure 15: PJM's Winter 2022-2023 Capacity Projections



However, TVA projected approximately 1,626 MW of load management available to respond to additional unplanned resource outages.

Southern. The Southern BA performed a winter 2022/2023 resource assessment assuming a 50/50 load forecast. Based on its winter assessment, the Southern BA believed that it could meet its projected winter peak demand of 41,300 MW with available generation and imports (based on normal weather conditions). The Southern BA's extreme winter forecast was 45,462 MW, slightly lower than its previous all-time winter peak demand record of 45,887 MW, which was set on January 7, 2014. To meet that extreme peak demand, Southern projected resource capacity of 53,759 MW, once 4,136 MW of planned and forced outages were deducted from available resources. This resulted in estimated reserves of 12,459 MW assuming the 50/50 load forecast and 8,297 MW for the 90/10 extreme load scenario. Southern BA also projected approximately 2,510 MW of load management available to respond to additional unplanned resource outages.

For assessing transmission system performance for the upcoming winter season, SERC (members include DESC, DEC, DEP, Santee Cooper, LG&E/KU, TVA, and Southern) conducted a 2022-2023 winter reliability study. The assessment studied an N-1 contingency analysis on the initial base case to determine whether there was adequate transmission for the upcoming winter season. SERC members also studied an "extreme weather" scenario under which a 12 GW power transfer was simulated from PJM to MISO South. A third study simulated what was termed as a "colder-than-normal" transfer case, which increased all generation in the SERC region that was online with available capacity and scaled the loads up in one subregion at a time, evaluating transmission adequacy given higher subregional demands that were 10 percent or higher above 50/50 forecasted levels. Overall, the above three studies did not show any transmission adequacy issues in the SERC subregions for the 2022-2023 winter season, and showed that potential thermal overloads identified in the studies could be mitigated with available operating guides or other mitigation strategies.

PJM. PJM performed a Winter 2022/2023 seasonal assessment assuming a 50/50 load forecast. PJM used power flow cases that simulated the expected system conditions for the 2022/2023 winter peak load period. For the PJM non-coincident load case, each transmission zone is set to its individual respective winter 50/50 peak load forecast value, without a reduction for load diversity and without considering any demand response resources that may be available. PJM also performed several sensitivity studies using the 50/50 non-coincident load case. Finally,

PJM calculated projected reactive interface transfer limits[112] for various interfaces.

As shown in Figure 15,[113] based on its winter assessment, PJM believed that it could meet its projected 50/50 winter peak demand of 136,867 MW with available generation (based on normal weather conditions). PJM's extreme winter forecast was 143,782 MW, slightly higher than its previous all-time winter peak demand record of 143,225 MW, which was set on February 20, 2015. To meet that extreme peak demand, PJM projected resource capacity of 157,314 MW, once 16.5 GW of generator outages, 4.2 GW of exports, 6.2 GW for the loss of its largest contingency (gas/electric single point of failure) and 6.1 GW for a no wind/no solar scenario were deducted from available resources. This resulted in estimated reserves of 16,233 MW assuming the 50/50 load forecast and 9,318 MW for the 90/10 extreme load scenario. However, PJM projected approximately 7.6 GW of load management available to respond to additional unplanned resource outages.

2. GENERATOR OWNERS'/OPERATORS' AND NATURAL GAS FACILITIES' WINTER SEASON PREPAREDNESS

a. Generation Resources' Seasonal Preparations

GOs/GOPs indicated that over 90 percent of generators that experienced an outage, derate, or failure to start had a cold weather preparedness plan in effect during the Event, and the same percentage used a pre-winter generating unit maintenance checklist in the fall. See section III for additional information on GOs/GOPs' cold weather preparation.

b. Natural Gas Infrastructure/Facilities' Seasonal Preparations

Natural gas infrastructure facilities took a variety of actions to prepare for winter.[114] Production facilities inspected and made repairs as necessary to insure functionality of heat trace and other heating systems, if applicable. They ordered and stocked essential winter supplies such as cinders for roads (used to access wellheads during icy road conditions), and portable generators. Some buried flowlines[115] to protect them from freezing, and/or added burners to increase temperatures on gas processing units. Natural gas processing entities purchased supplies such as tarps, batteries, spare parts, and mobile heaters, and performed maintenance such as repairing insulation on pipes and checking mobile heaters to ensure they were in good working order.

Pipeline operators implemented their winter operations programs which included performing preventive maintenance on compressor stations and at receipt and delivery points, testing all emergency equipment, servicing backup power supply sources, and performing any necessary equipment overhauls, among other tasks.

112 Interface transfer limits are the MW flow limitation across a transmission interface to protect the system from large voltage drops or collapse caused by any viable contingency.

113 Reproduced with permission of PJM and © PJM.

114 The Team instructed all natural gas entities that it asked for data to provide data for the following states, if applicable: New York, Delaware, Kentucky, Maryland, New Jersey, North Carolina, South Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, District of Columbia, Georgia, Alabama, Mississippi, Louisiana, Arkansas, Missouri, Iowa, Illinois, Minnesota, Wisconsin, Michigan, Indiana.

115 Flowline is the flow connection from the wellhead to the separation facility, pipeline or storage unit. *See* Piping and pipeline systems - PetroWiki (spe.org).

III. CHRONOLOGY OF EVENTS

A.Preparations in Advance of the Winter Storm

1. WEATHER FORECASTS PREDICTED SEVERE COLD FOR DECEMBER 23-24 AS EARLY AS DECEMBER 14

Similar to Winter Storm Uri, and past major winter storms, the storm that came to be called Winter Storm Elliott[116] was forecast many days in advance. On Wednesday, December 14, at 3 p.m., the National Weather Service issued its "US Hazards Outlook" covering the period that included December 22 to 25 and published its "8-14 Day Temperature Outlook" graphic, as shown in Figure 16, below, showing that large portions of the eastern U.S. were highly likely to experience below normal temperatures.[117]

In its outlook, the NWS predicted that "[a] negative Arctic Oscillation (AO) pattern forecast over North America later in December is expected to promote below normal temperatures" with "[h]igh risk of much below normal temperatures for much of the [contiguous U.S.] east of the Rockies excluding the Northeast, Thu[rsday through Sunday], Dec[ember] 22-25."[118]

SPP and MISO RCs. On the following day, December 15, SPP and MISO first identified the risk that the forecast extreme weather posed to their respective systems, with projected impacts beginning December 21-22.

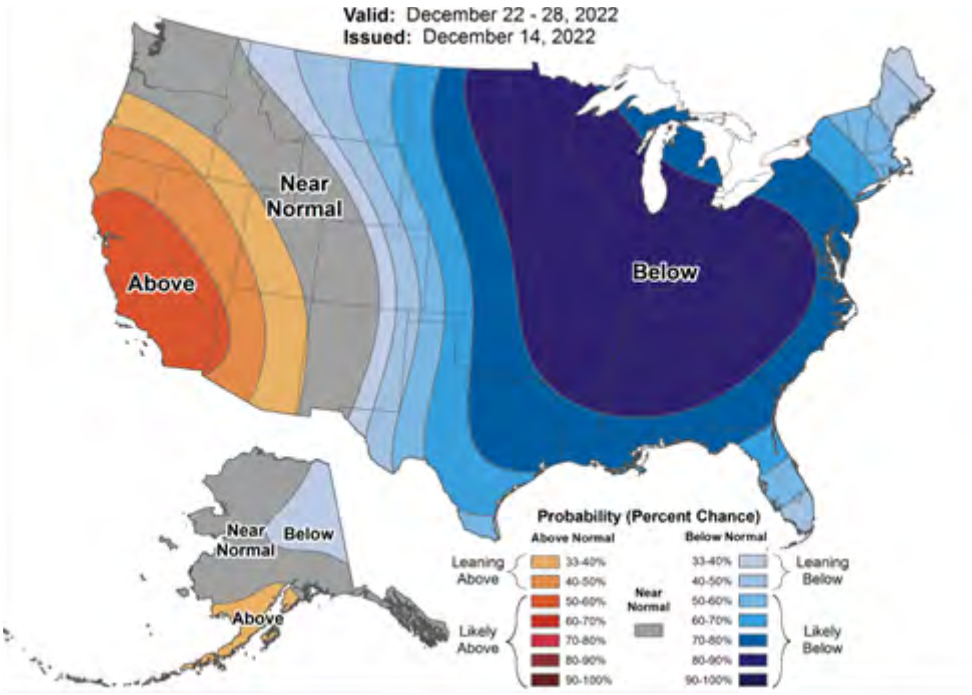
TVA, Southern, and VACAR-South RCs. On December 14, TVA recognized that a major arctic outbreak was likely for Christmas weekend (December 23 to 25), and on December 19, communicated that across its organization. On December 16, Southeastern RC recognized the threat posed by the forecast and discussed on Southeastern RC's daily RC calls from that day until December 25. It also began sharing forecast system conditions via Southeastern RC emails on December 16. Duke updated internal stakeholders on December 19 regarding its concern with the forecast winter conditions, which it expected to be a powerful cold front arriving on December 23, bringing falling temperatures and precipitation (mostly rain).

116 The National Weather Service of the National Oceanic and Atmospheric Administration does not name winter storms because, according to its then-Deputy Director of Public Affairs, "[w]inter storms are diverse with conditions that evolve throughout the storm's life. That is why our (NWS) forecasts, watches and warnings focus on specific impacts such as wind conditions, snowfall, ice, temperature, visibility, and other impacts. Winter storm conditions can vary widely and over a very large area, from community to community. It's critical that people understand how a storm will impact them, in their area or where they are going." A private company, The Weather Channel, began naming severe winter storms in 2012 and those names have been recognized by some, but not all, media sources. KSAT, for example, said that it would continue to follow the NWS and not recognize names for winter storms. Sarah Spivey, *Let's chat: Do winter storms really have names? The unofficial naming system has gained some popularity, but experts caution against the naming of winter storms*.,KSAT NEWS (Oct. 19, 2002) https://www.ksat.com/weather/2022/10/19/lets-chat-do-winter-storms-really-have-names/. In 2021 the Team did not recognize the naming of Winter Storm Uri, but given the widespread use of the winter storm names by media discussing both the 2021 and 2022 events, the Team used the names in the Report.

117 *See*, Melissa Ou, *National Weather Service Climate Prediction Center "U.S. Hazards Outlook"*,cpc.ncep.noaa.gov/products/archives/hazards/data/2022/KWNCPMDTHR.20221214, and "8-14 Day Temperature Outlook" graphic at 814temp.20221214.fcst.gif (3300×2550) (noaa.gov). *See* also examples of coverage in popular media: Anna Skinner, *Artic Blast to Bring Dangerous Below-Zero Temperatures to These States*, Newsweek (Dec. 20, 2022), https://www.newsweek.com/arctic-blast-dangerous-below-zero-temperatures-these-states-1768512; and Pandora Dewan, *Bomb Cyclone Photos: What to Expect From Freezing Weather Forecast*, Newsweek (Dec. 20, 2022), https://www.newsweek.com/bomb-cyclone-photos-freezing-weather-forecast-1768515#:~:text=Elliott%20is%20expected%20to%20arrive%20in%20the%20Pacific,the%20Midwest%20and%20parts%20of%20the%20East%20Coast.

118 Contiguous U.S. includes the 48 states south of Canada, including the District of Columbia.

Figure 16: National Weather Service 8-14 Day Temperature Outlook – December 14, 2022



PJM. The storm was expected to move into PJM's footprint on December 23, bringing snowfall and high wind gusts combining to create blizzard conditions, and freezing rain in the central Appalachians with ice accumulation of 0.10 to 0.25 inches. On December19, PJM weather forecasting alerted PJM Dispatch via email of upcoming blizzard conditions and extreme cold.

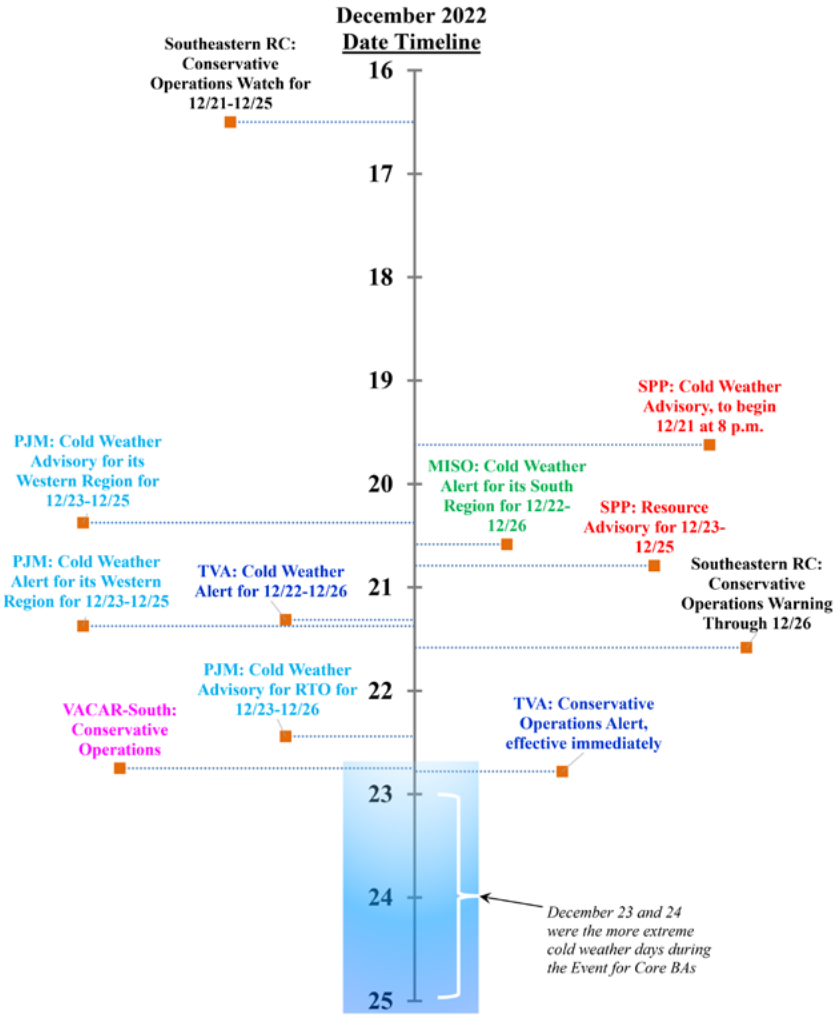
2. ALERTS ISSUED BY GRID ENTITIES AND EXPECTED PREPARATIONS FROM DECEMBER 16 THROUGH 22

All BAs and RCs have established emergency operating procedures (emergency procedures) as required by the Reliability Standards, particularly EOP-011-2, Emergency Preparedness and Operations.[119] Additionally, entities may have their own specific operating procedures that coordinate with or supplement the BA/RC emergency procedures. As part of their responsibilities under the emergency procedures, BAs and RCs issue cold weather advisories, alerts, and conservative operations notices, as necessary.[120] Each entity's emergency operating procedures document the actions that are required by the relevant TOs/TOPs and GOs/GOPs.

119 RSCompleteSet.pdf (nerc.com)

120 For purposes of this discussion, the Report uses the terms "advisories," "alerts," and "conservative operations notices" to encompass the range of notices that BAs and RCs issue as part of their respective emergency operating procedures, https://www.nerc.com/pa/Stand/Reliability Standards Complete Set/RSCompleteSet.pdf. Each BA and RC uses specific defined terms for their notices. *See, e.g.,* PJM Manual 13: Emergency Operations (Aug. 24, 2023), https://www.pjm.com/-/media/documents/manuals/m13.ashx (including PJM's defined terms for its alerts and notices).

Figure 17: RC Watches, Advisories, Alerts and Warnings Issued From Friday, December 16 Through Thursday, December 22, 2022



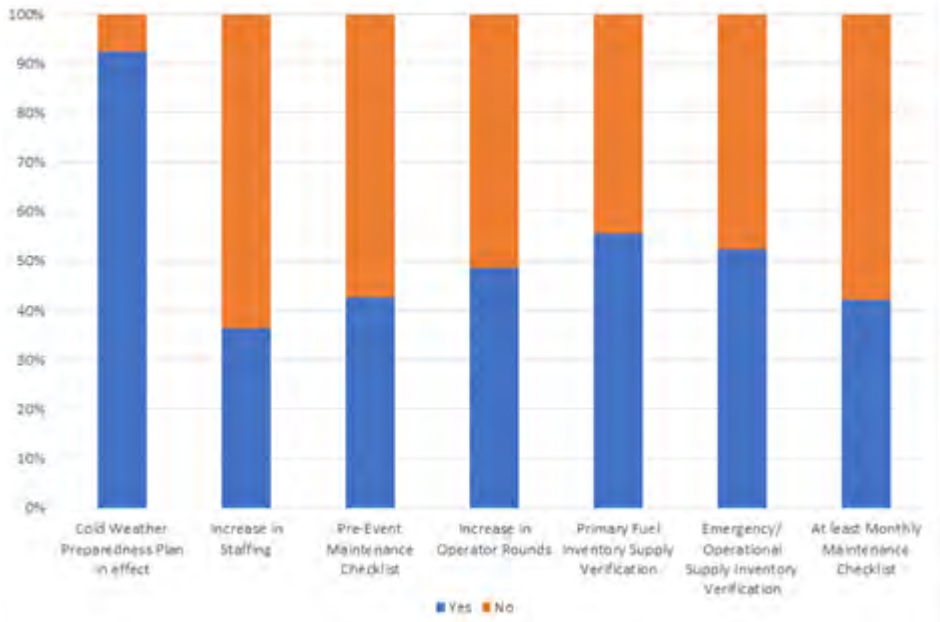
Before and during the Event, affected RCs issued cold weather advisories[121] and alerts,[122] as well as conservative operation declarations. Figure 17, above, summarizes the notices issued in advance of the more extreme cold weather days during the Event (including conservative operations declarations) from December 16 through December 22.

BAs issue the in-advance cold weather alerts and advisories to their stakeholders, including those BES

121 By way of example, PJM's cold weather advisories advised PJM members to prepare to (1) take freeze protection measures; (2) review weather forecasts, determine any forecast operational changes, and notify PJM of any changes; and (3) update PJM with operation limitations associated with cold-weather preparedness (e.g., generator capability and availability, fuel supply and inventory concerns, fuel switching capabilities, environmental constraints, and generating unit minimum temperatures).

122 Again, as an example, PJM's cold weather alerts stated that generation dispatchers should: (1) review fuel supply/delivery schedules in anticipation of greater-than-normal operation of units; (2) monitor and report projected fuel limitations to PJM dispatcher and update the unit Max Run field in PJM's Markets Gateway if less than 24 hours of run time is remaining; and (3) contact PJM Dispatch if it is anticipated that spot market gas is unavailable, resulting in unavailability of bid-in generation.

Figure 18: Cold Weather Event Preparation by GOs/GOPs with Outages/Derates/Failures to Start



GOs/GOPS within their footprints.[123] The GOs/GOPs are not required to respond to the alerts or verify that they completed their winter readiness steps (i.e., no confirmation to the BA that the generating unit is prepared for the forecast cold weather).

3. NEAR-TERM PREPARATIONS BY GENERATION OWNERS/OPERATORS

Under the currently effective Reliability Standards, GOs/GOPs are required to have cold weather preparedness plans that include inspection and maintenance of the generating unit's freeze protection measures.[124] A common method for implementing inspection and maintenance of freeze protection measures is the use of inspection and maintenance checklists. Over 40 percent of the GOs/GOPs that experienced an outage, derate or failure to start during the Event performed monthly inspections using their checklists, with a subset of those inspecting weekly.Approximately 40 percent of those that have a pre-winter checklist (used to prepare for the season) implement a "pre-event" checklist (which can be used to confirm that nothing has degraded, and that no new maintenance issues have arisen, since the pre-winter checklist was completed).[125] Sixty percent do not perform pre-event inspection or maintenance checklists, which suggests room for improvement. Figure 18, above, illustrates the responses provided by GOs/GOPs that had at least one generating unit that incurred an outage, derate, or failure to start during the Event, when asked whether they performed various near-term preparations. Other areas of cold weather preparedness that could benefit from improved effort include the actions that had 50 percent or less adoption rates in Figure 18, such as providing additional staffing (during an event), increasing operator rounds, verifying inventory of primary fuel and emergency supplies, and using a monthly maintenance checklist.

123 The Report discusses notices issued after December 22 during the Event in Section III.B.3., below.

124 Reliability Standard EOP-011-2, Requirement R7.2. RSCompleteSet.pdf (nerc.com).

125 For example, outages have resulted from insulation being moved away from pipes to perform work and not being properly replaced before the onset of freezing temperatures.

4. NEAR-TERM PREPARATIONS BY NATURAL GAS INFRASTRUCTURE ENTITIES

As the storm approached, natural gas infrastructure facilities supplemented their seasonal prparations. Some entities took steps to determine that readiness had not declined since the pre-winter preparations, along with implementing short-term measures to be taken shortly before a major storm.

Production. Producers stationed additional field personnel and supplied them with resources to prevent and manage freeze offs by ensuring functionality of heat trace and other heating systems, by injecting methanol, and by increasing flow rates.[126] They pre-arranged for removal of snow and ice from roads to ensure safe access to sites and facilities, along with prepping the roads with cinders in advance of cold weather conditions. Producers also pre-staged materials such as water tanks and portable backup generation where they would most likely be needed. Some producers used tarps and deployed shelters (which could hold heaters, if necessary) to protect equipment prone to freezing. They lowered levels in or emptied water, condensate, and oil tank levels at facilities to which access was expected to become difficult. Most conservatively, two producers anticipated production declines and proactively reduced the amount of natural gas that they marketed in the short term.

Processing. Processing companies increased personnel on duty to respond to plant issues and equipment failures, ensured adequate supplies of methanol, stocked critical spare parts (tarps, batteries, etc.), performed any last-minute maintenance (e.g., repair insulation), and coordinated with producer customers and purchasers of the residue gas produced by the plant. Finally, to the extent that they relied upon some form of an alternative power source (e.g. on-site backup generators), they serviced the power source to ensure operation during the Event.

Pipelines. Pipelines in the path of Winter Storm Elliott began to monitor the weather forecast as the storm began to form, while also implementing cold weather plans and holding internal meetings.[127] These meetings focused on estimated load forecasts, storage strategies, maintenance activities, and line pack management strategies. Due to anticipated operational challenges, some pipelines staffed key compressor stations that ordinarily are not staffed but are essential during peak demand for system reliability. Some tested emergency equipment in advance of the Event.

All pipelines proactively managed and monitored line pack and system integrity. Some pipelines issued critical notices in advance of the storm, ranging from weather advisories to OFOs. Each pipeline increased line pack in anticipation of high demand, supply loss, and potential equipment problems. Most also prepared storage facilities to allow them to withdraw natural gas – including liquid natural gas – to meet customer requests and respond to anticipated increased demand.

5. SHORT-TERM LOAD FORECASTS BY GRID ENTITIES

Accurate short-term load forecasts (that is, the load forecasts BAs performed just days in advance or during the Event, with knowledge of the forecast extreme cold weather) assist with committing and scheduling resources. Many of the BAs normally aim to keep their load forecast error near or below three percent. For example, PJM's daily peak forecast error only exceeded its target load forecast error of up to three percent on a single day between December 1 and December 23, 2022.

126 The Gas Technology Institute completed a report as part of the inquiry into the 2011 Southwest cold weather event, which detailed techniques for preventing freezing of natural gas production. L. Brun Hilbert et al., *Natural Gas Production in Extreme Weather*, Pipeline & Gas Journal, (June 2021), https://www.pgjonline.com/magazine/2021/june-2021-vol-248-no-6/guest-commentary/natural-gas-production-in-extreme-weather. Other methods included water removal using glycol dehydration and heating methods such as catalytic heaters, fuel line heaters and steam systems.

127 One pipeline held a November 2022 meeting with its customers regarding cold weather preparedness. Although this action was an outlier, it was an effective practice and the Team encourages all pipelines to consider holding similar meetings in the future.

Although BAs projected higher electricity demands for the impending winter storm, most core BA significantly underestimated the peak loads in advance of December 23 and 24, the most extreme cold weather days of the Event. Figures 19 and 20 below, show the Core BAs' four-, three-, two- and day-ahead forecasts versus actual peak loads for December 23 and 24, respectively. Figure 21, below, shows their Mean Absolute Percentage Error (MAPE) across the four-, three-, two-, and day-ahead peak load forecasts for December 23 and 24.

Figure 19: BAs' Four-, Three-, Two-, and Day-Ahead Peak Load Forecasts vs. Actual[128] Peak Loads (Percent Difference) For December 23, 2022

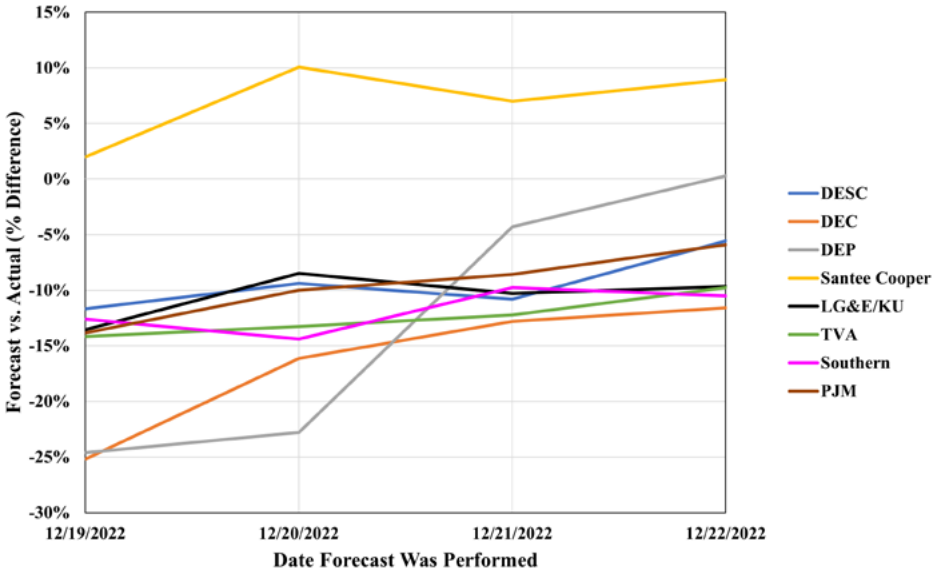
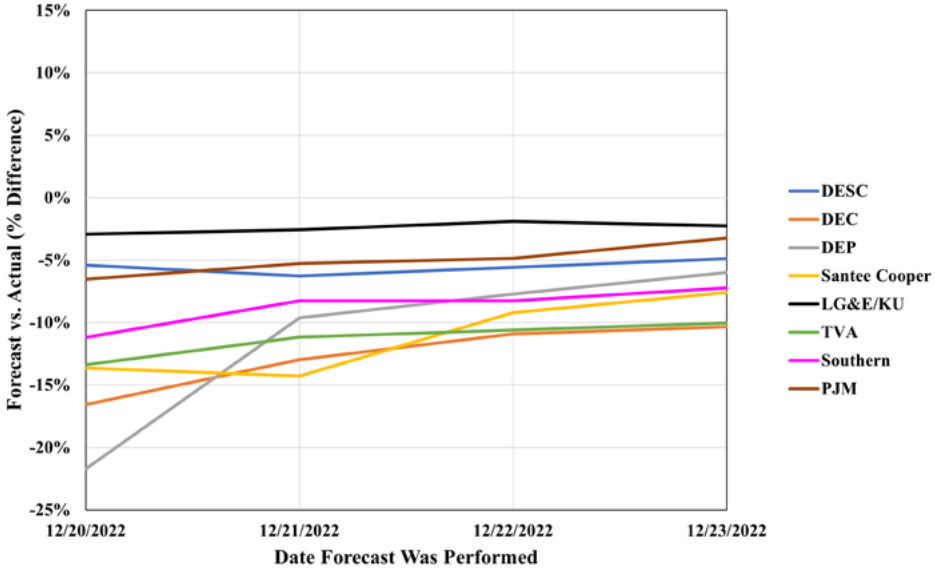
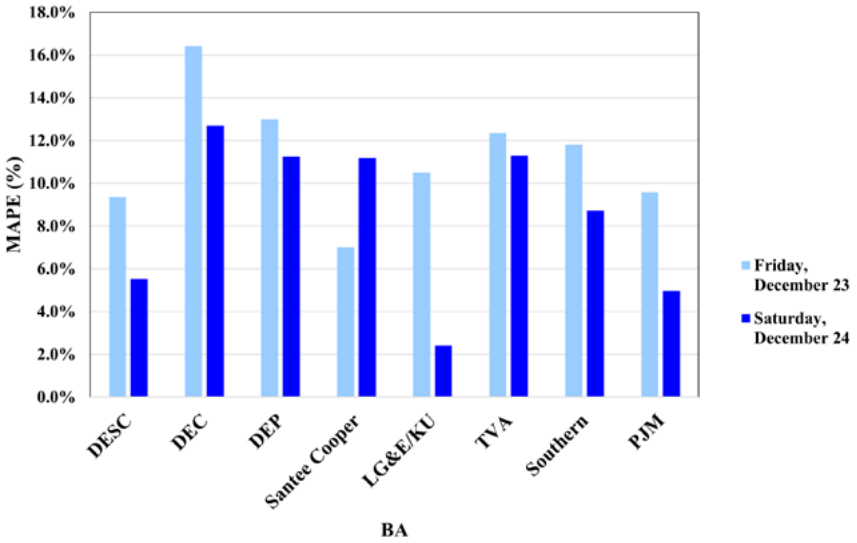


Figure 20: BAs' Four-, Three-, Two-, and Day-Ahead Peak Load Forecasts vs. Actual Peak Loads (Percent Difference) For December 24, 2022



128 For Figures 19, 20, and 21, for BAs that implemented load management measures during their respective peak load timeframes, actual peak loads used for calculations are based on BAs' estimated peak loads without load management.

Figure 21: Mean Absolute Percentage Error (MAPE) For BAs' Four-, Three-, Two-, and Day-Ahead Peak Load Forecasts for December 23 and 24, 2022



All of the BAs use weather data as inputs into their short-term forecasts. Most use only three years of data to train their models, which can be problematic if the conditions experienced have no similar day within the past three years. Some BAs have their own meteorologists, while others use only external vendors for weather forecasts. Two BAs automatically add buffers (MW or percentage of load forecast) to account for potential load forecast error. Some have a single system-wide forecast, while others split their forecast to reflect differences in the makeup of their load (e.g., mountains vs. beaches).

Figure 22, below, summarizes how each BA approaches these short-term load forecasts.

Figure 22: Summary of BAs' Short-Term Load Forecast Processes

	Weather Forecast Data	Short-Term Load Forecast Model
DEC, DEP	Internal meteorology team produces forecast.	Uses models developed by three external vendors and projects load based on evaluation of their outcomes. Usually picks highest for extreme cold weather day, or looks for historical day to match. DEP prepares east and west (Asheville only) forecasts.
DESC	Obtains weather data from third-party vendors.	Based on weather forecast model and load model inputs, uses combination of external vendors and one internal model for developing load forecast. Incorporates solar inputs, and any manual adjustments deemed necessary to account for lack of similar days to produce a seven-day hourly load forecast.
LG&E/KU	External weather information providers, vendors.	Short-term load forecast is an aggregate of the load forecasts provided by the LSEs in the LG&E/KU BA area. In week ahead/next-day studies use a five percent buffer.
PJM	Three external weather information vendors, uses weighted average based on recent performance.	Internal team manages suite of neural-network and pattern- matching models with final short-term load forecast based on staff evaluation. Benchmarks day-ahead forecast against actual for tracking of forecast error.

	Weather Forecast Data	Short-Term Load Forecast Model
Santee Cooper	External weather information providers, vendors	Primary short-term load forecast is provided by an external vendor and evaluated against alternative forecast provided by another vendor. Uses 100 MW (approximately 1.8 percent of winter season peak) adder for load forecast error.
Southern	External weather information providers, vendors	Next 10-days' hourly weather forecasts are provided by external vendors, with multiple cities' peak load weighted for input to load forecasting models, which are neural-network based. Southern has large number of models producing load forecasts, including a vendor-supplied forecast that uses distribution-level metered load data as inputs, which has proven to be the most accurate of their vendors' forecasts over the past two years for the 1-5 day-ahead load forecasts.
TVA	Two external weather information vendors feed into its load forecast software.	Internal blend of three load forecast models from vendors, based on three-year history, informed by weather data and weather forecast. If no similar event in the three-year history, look for similar events in more distant past to adjust/extrapolate the load forecast.

6. GRID ENTITIES' OPERATIONAL PLANNING ACTIONS TO PREPARE FOR EVENT

Given the higher electricity demands forecast for the upcoming Winter Storm Elliott, BAs arranged for resources to meet those demands, including attempting to return resources to service that were offline before the storm (e.g., for periodic maintenance). Planned generator outages are typically scheduled months or even years in advance, to perform necessary maintenance, or in the case of nuclear power plants, refueling. BAs in organized markets can ask GOs/GOPs to reschedule their planned generation outages for system reliability, but they cannot require the GOs/GOPs to do so.

a. Generation Returned to Service Prior to Most Severe Event Conditions

Forced outages and derates for the Event Area remained relatively constant (41,607 MW on December 21 versus 42,856 MW on December 23) before the worst part of Winter Storm Elliott began to impact the Event Area.[129] Figure 23 shows the planned and unplanned generation outages and derates within the Event Area from the start of December 21 to the start of December 23.[130] Overall, some BAs had more success than others in returning to service generation that was on outage before the worst period of the Event. For example, Santee Cooper's system operations coordinated with a gas generator in the week preceding the storm to return the unit to service following an unplanned outage due to a pump failure. The pump was repaired on December 21, restoring 28 MW of generating capacity. LG&E/KU was able to return to service nearly all of its generation that was on planned outages before the Event. A total of 8,501 MW of planned outages were returned to service within the BA footprints listed in Figure 23 before the worst part of Winter Storm Elliott began to impact the Event Area. Beyond December 23, GOs continued efforts to return prior-outaged generation to service where feasible, which offset the total unavailable generation during the Event.

129 Forced outages often occur due to equipment failure or freezing and when and if a unit can be timely returned to service is unpredictable.

130 The start of December 23 (with the exception of the SPP, which was impacted with increased unplanned generation outages during the Event beginning December 22) was prior to the most severe drops in temperature. Accordingly, SPP is not included in Figure 23 to provide a more uniform comparison.

Figure 23: Planned and Unplanned Generation Outages in BA Footprints, at the Start of December 21, and December 23, 2022 (Prior to the Most Severe Drops in Temperature)

BA	Planned at the start of :		Unplanned at the start of:		Total Unavailable, at the start of:		21st — 23rd Decrease in Generation Out-of-Service
	Dec. 21 (MW)	Dec. 23 (MW)	Dec 21 (MW)	Dec. 23 (MW)	Dec. 21 (MW)	Dec. 23 (MW)	(MW)
DEC	391	391	1,662	1,820	2,053	2,211	-158
DEP	983	1,811	507	841	1,490	2,652	-1,152
DESC	7	7	350	133	357	140	217
LG&E/KU	704	10	138	631	842	641	201
MISO	12,610	11,178	20,824	20,004	33,434	31,182	2,252
NYISO	3,161	2,085	2,414	3,119	5,575	5,204	371
PJM	9,586	6,253	12,582	12,787	22,168	19,040	3,128
Santee Cooper	570	570	400	110	1,540	1,250	290
Southern	3,022	2,486	758	913	3,780	3,399	381
TVA	3,153	895	1,972	2,498	5,125	3,393	1,732
TOTAL	34,187	25,686	41,607	42,856	75,794	68,542	7,252

b. Generation Committed Early for Reliability

In general, all BAs within the Core Event Area thought in advance of the Event that they individually had sufficient resources to meet their respective forecast electricity demands expected during Winter Storm Elliott. The BAs did not discount the possibility of some level of unplanned generation outages as a result of the storm, but those with smaller reserve margins thought they could purchase (i.e., import) power from external sources, or rely on bringing online quick-start/short-lead-time generating units to meet their peak electricity demands. TVA committed all available generation seven days prior to the Event and told the GOP when they would need the generation to be online. Santee Cooper planned to staff two generating units for quick start-up that would otherwise have longer lead times. SPP made multiple long-lead-time generating unit commitments: (1) on December 21, for the next two days, (2) on December 22, for Christmas Eve, and (3) on December 23, for Christmas Day, to improve the likelihood of having the additional online capacity for those days, as well as committing short-lead-time natural gas-fired units so that they could procure sufficient natural gas before the holiday weekend.

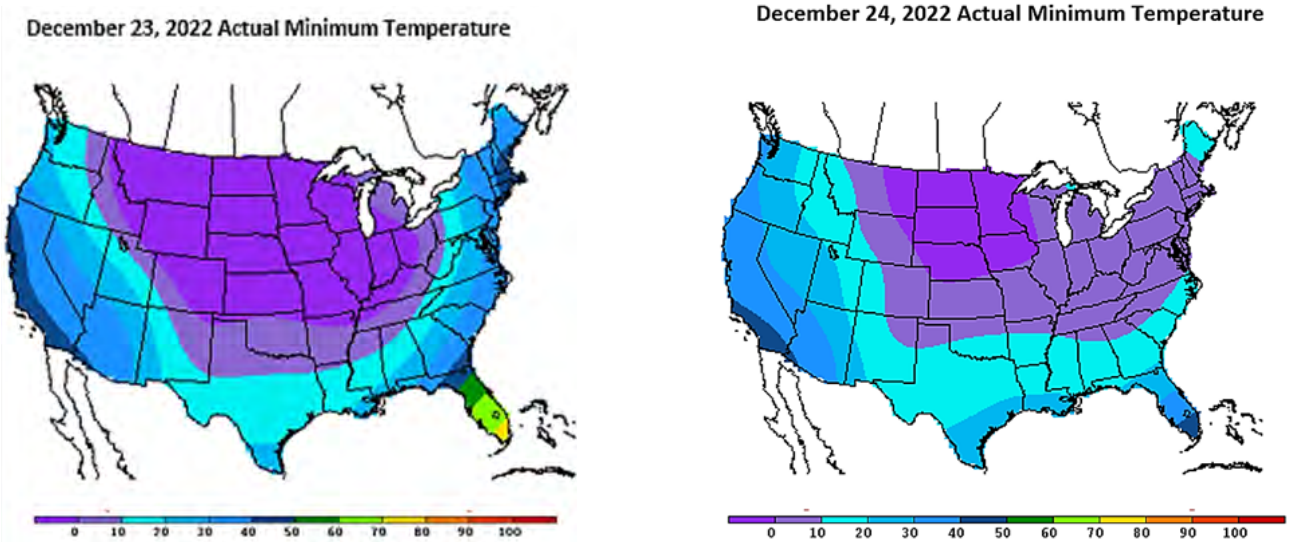
c. Transmission Facilities Returned to Service Before the Event

Some TOPs provided details on actions they took to return transmission facilities to service that had been on outage prior to the Event. TVA returned several transmission facilities to service before the Event, including one transmission line and two circuit breakers. Southern restored a transmission line that improved its ability to transfer power to and from Florida utilities, and additionally restored to service two other transmission lines, a circuit breaker, and two power transformers. PJM increased its transfer capability through coordination with its TOs which resulted in the return to service of two major transmission lines early on December 23. DEP and DEC indicated that they had no significant transmission outage plans or outages before or during the Event.

B. December 22 - 24: Extreme Cold Weather Conditions Lead to Widespread Generation Outages and Natural Gas Infrastructure Issues, Forcing Grid and Pipeline Operators to Make Difficult Decisions, Such as Shedding Firm Electric Load or Curtailing Firm Pipeline Customers

On December 22, the storm hit the Midwest, bringing snow, low temperatures and strong winds (with gusts up to 60 miles hour) and wind chill temperatures as low as -42 degrees. Although accumulation was minimal, the combination of snow and gusting winds caused blizzard conditions in some areas. The storm moved eastward and by December 23, Chattanooga, Tennessee had dropped from 49 degrees to 7 degrees. Similarly, Charleston, West Virginia dropped 42 degrees on December 23 (with wind gusts over 50 mph). The actual lows for December 23 for the Midwest and South Central U.S. were largely 20 degrees or below. From December 23 into 24 the extreme cold finally reached the east coast, and the actual lows for December 24, as shown on Figure 24, below, reflect that except for part of Florida, the lows were below 20 degrees. These temperatures were 15 to 30 degrees lower than normal low temperatures, with some elevated areas greater than 30 degrees lower (than normal low temperatures), as seen in Figure 25, further below.

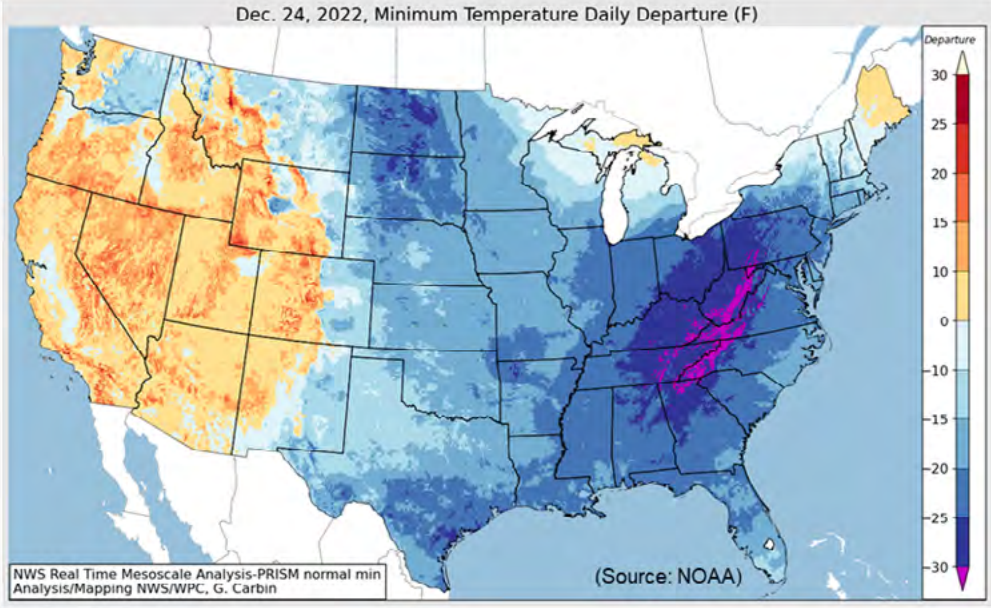
Figure 24: December 23 and 24, 2022 Actual Minimum Temperatures – Lower 48



1. UNPLANNED GENERATING UNIT OUTAGES RAPIDLY ESCALATE

All of the BAs went into the Event with some measure of generation unavailable, but during the afternoon and evening of December 22 unplanned generation outages began to rapidly escalate. In fact, of the more than 371,000 MW of generation that was lost due to forced outages, derates and failures to start during the entire Event—a period stretching from December 21 to December 26—more than 20 percent (74,000) of all generation losses would occur in the 12 hours between 6:00 a.m. and 6:00 p.m. on December 23.

Figure 25: Departures from Normal Minimum Low Temperatures, December 24, 2022



SPP (outages began afternoon of 12/22). SPP experienced "key generation losses in the eastern part of SPP's footprint"[131] beginning December 22 at around 3:40 p.m.[132] and continuing into the evening and early morning hours. By December 23 at 10 a.m., unplanned generation outages and derates in the SPP footprint escalated by 8,900 MW.

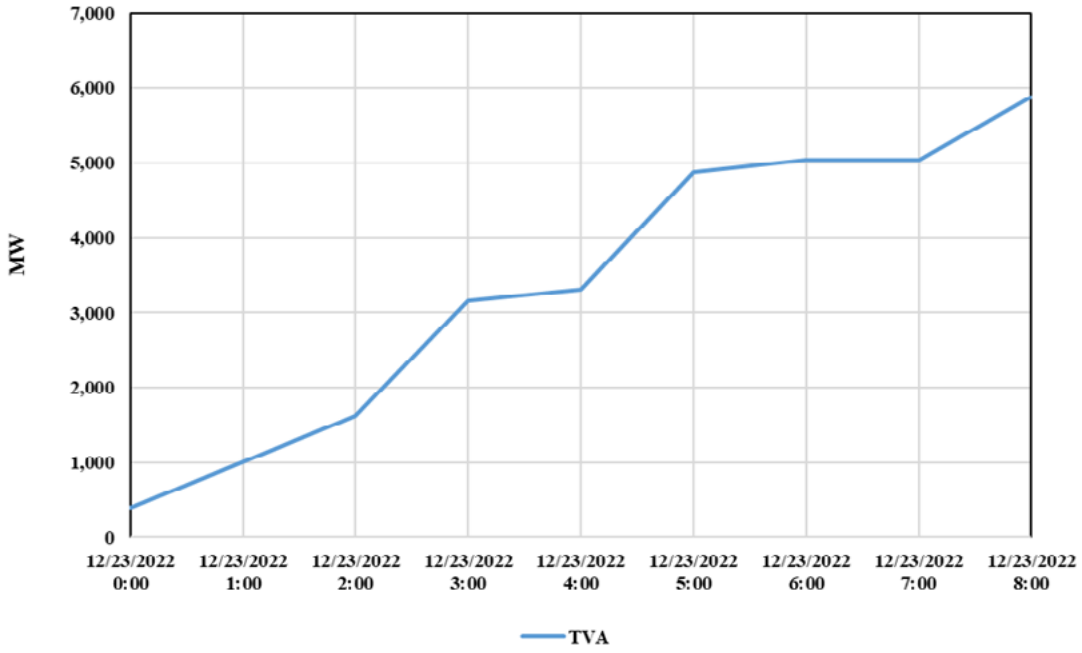
MISO (outages began early 12/23). In MISO, unplanned generation outages and derates began to escalate on December 23 and MISO BA operators were faced with over 6,000 MW of incremental unplanned generation outages; by 9:15 a.m., 2,000 MW of unit trips and failures to start in MISO South contributed to MISO BA operators implementing emergency measures.

TVA (outages began early 12/23). TVA unplanned generation outages began shortly before 1:00 a.m. on December 23. Outages and failures to start escalated sharply to a total of nearly 6,000 MW by 8 a.m. as shown in Figure 26, equivalent to nearly 20 percent of its peak load.

131 *See Review of SPP's Response to the Dec. 2022 Winter Storm* (April 2023), at 10.

132 All times stated within the Report, unless otherwise specified, are in Eastern Standard Time, even if the entity is in the Central Time Zone (EST).

Figure 26: Incremental Unplanned Generation Outages in the TVA BA Footprint During Event, December 23, 12 a.m. to 8 a.m.

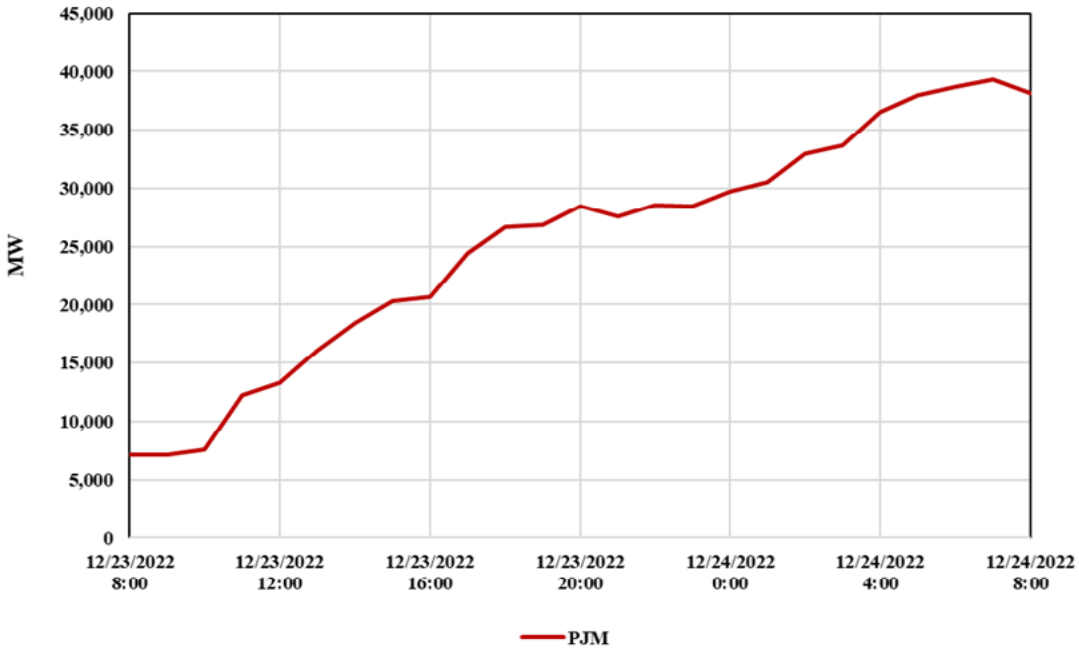


LG&E/KU (outages began early 12/23). Beginning at 1:28 a.m. on December 23, then throughout the morning and afternoon, generators experienced derates and outages due to cold weather and mechanical issues; at 1:08 p.m., significant power plant derates due to fuel issues (discussed further in subsection (a) below) led to an approximately 900 MW reduction, including one unit trip and six units that were derated to operate at minimum output for approximately 50 hours (until December 25, 4:00 p.m.); then from 3:39 p.m. to 6:44 p.m., an additional 500 MW of unplanned generation outages occurred.

PJM (outages began about 4 a.m. on 12/23). Unplanned outages and derates began to escalate shortly after 4 a.m. on December 23, then from about 8:00 a.m. to 5:00 p.m., rapidly escalated at a rate of over 2,200 MW per hour (for a total of approximately 20,000 MW); outages continued to escalate until December 24 at 8:00 a.m.[133] Over the 24-hour period, PJM sustained nearly 33,000 MW of unplanned generation outages and derates, as illustrated in Figure 27.

133 This outage data, like all other generation outage data unless found on a graphic credited to an entity other than the Team, is based on the data the Team obtained directly from the GOs/GOPs.

Figure 27: Incremental Unplanned Generation Outages in the PJM BA Footprint During Event, December 23, 8 a.m. to December 24, 8 a.m.



DEC and DEP (outages began late evening 12/23). In the DEC and DEP footprints, unplanned generation outages and derates began at about 11:30 p.m. on December 23, and by December 24 at 8 a.m., DEC and DEP had lost about 2,000 MW; outages continued into the early afternoon of December 24.

Southern (outages began midnight 12/23). From December 24, 12:00 a.m. to December 24, 2:00 a.m., Southern had approximately 500 MW of gas/oil generating unit capacity forced offline; then from 2:00 a.m. to 6:00 a.m., it had an additional 890 MW of gas/combined cycle generating capacity forced offline (1,390 MW total incremental unplanned outages from midnight to December 24, 6:00 a.m.).

DESC (outages began early 12/24). Six generating units, over 1,000 MW of generation total, sustained unplanned outages from December 24, 12:30 a.m. until about 9:10 a.m.

Santee Cooper (outages began early 12/24). Santee Cooper experienced over 500 MW of unplanned generation outages and derates beginning December 24 at 2:35 a.m. to 7:00 a.m. In addition, a boiler tube leak forced a 300 MW unit offline late December 23; it was unrelated to the weather but increased Santee Cooper's total unplanned generation outages to over 800 MW.

GOs reported to several BAs, including TVA and LG&E/KU, that many of the generating unit outages were due to Freezing Issues.

a. Rapid Emergence of Fuel Issues

Fuel Issues were a significant driver of the unplanned generation outages and derates early on December 23. Notably, within PJM, outages caused by Fuel Issues grew eight-fold between 6:00 a.m. and noon on December 23—and fifteen-fold between 6:00 a.m. and 6:00 p.m. that same day, outpacing the increase in outages due to Mechanical/Electrical Issues. By midnight on December 23, the total unplanned generation shortfall due to Fuel Issues exceeded the shortfall due to Freezing Issues, as seen in Figure 28, below.

Figure 28 Growth in Unplanned Generation Outages, Derates, and Failures to Start for Three Most Common Causes of Generation Outages in PJM, December 22 to 24

PJM	12/22/2022	12/23/2022				12/24/2022	
	Midnight	6:00am	Noon	6:00pm	Midnight	6:00am	Noon
Mechanical/Electrical Issues	5,746	6,448	7,497	10,927	12,458	16,909	16,130
Fuel Issues	576	597	5,062	9,014	11,133	13,283	12,709
Freezing Issues	1,966	2,625	5,436	10,770	10,379	12,979	12,928

Although the growth in Fuel-Issues-related generation loss was most acutely seen in PJM, virtually all of the BAs/RCs saw generation lost or derated due to Natural Gas Fuel Issues[134] on December 23 and 24. SPP, TVA, LG&E/KU, and VACAR-South RC all reported gaining awareness on December 23 or 24 that generating units were struggling to find adequate natural gas supply or that pipelines were struggling or unable to maintain adequate pressure at certain locations.

SPP. SPP began receiving system overrun limitation alerts for gas pipelines during the week of December 19. This was an early indication of potential fuel supply problems and SPP considered the alerts when evaluating forecasts of resource unavailability. Between December 22 and 25, SPP received communications from plant operators about fuel procurement issues through operator-to-operator communication and via plant operator outage entries made in SPP's generator outage management system.

MISO. Gas supply availability contributed to increased unplanned outages, particularly on the afternoon of December 23, that pushed MISO into emergency procedures. Generation in the MISO Region is connected to nearly three dozen interstate and intrastate pipelines, and the top five pipelines serve over 36 GW of gas generation in MISO. MISO became aware of gas availability issues when gas generators began communicating outages to MISO's generator outage management system, indicating an unavailable commitment status in their real-time offers, and/or phoning to inform the MISO Generation and Interchange operator of their expected outage submission due to gas unavailability. By the end of the day on December 23, MISO had experienced 23 GW of gas generation forced outages. Nearly 50 percent of gas generators reported outages to MISO that were due to Fuel Transportation/ Supply Issues. Most of these were forced/emergency outages with little or no prior notice to MISO Operations. Such a significant volume of unplanned outages eroded MISO's reserve margin and contributed to MISO's declaration of emergency procedures on December 23. Increased fuel risk and associated uncertainty regarding gas generator availability on December 24 contributed to MISO operators committing additional generation.

TVA. GOs reported to TVA BA operators that some generating units were experiencing outages due to low natural gas fuel pressure. For example, on December 24, at 8:00 a.m., a 900 MW combustion turbine (CT) / combined cycle (CC) site was derated by 243 MW due to low natural gas delivery pressure issues. Further, on December 25, at 4:20 a.m., a 1,075 MW multi-CT/CC site was reduced by 978

134 As described earlier in the Report, Natural Gas Fuel Issues include the combined effects of decreased natural gas production; cold weather impacts and mechanical problems at production, gathering, processing and pipeline facilities resulting in gas quality issues and low pipeline pressure; supply and transportation interruptions; curtailments and failure to comply with contractual obligations. Additionally, it includes shippers' inability to procure natural gas due to tight supply, prohibitive, scarcity-induced market prices, or mismatches between the timing of the natural gas and energy markets.

MW to minimum output (97 MW total), because of low gas delivery pressure issues.

LG&E/KU. On December 23, at 1:09 a.m., pipeline pressures for two natural gas-fired generating stations began to drop below the contract limits; and at 1:08 p.m., LG&E/KU experienced approximately 900 MW in generation losses (unit trip and six units derated) arising from low delivery pressures on a pipeline supplying these generating units.

DEC. On December 24, Transco pipeline notified DEC BA operators of low pressure issues and the potential timeline to recover pressure. The low pressure affected two natural gas-fired units, totaling 178 MW in unplanned generation derates.[135]

PJM. PJM had 186 generating units that failed to start. One-third of those were natural gas-fired CTs and CC units that reported to PJM that they did not have fuel or were fuel-limited.

135 Derates occurred after the DEC BA morning peak demand ended and did not impact DEC's ability to meet ongoing system demand, which remained at lower levels throughout the remainder of the holiday weekend.

Fuel Switching

As the 2021 Report noted, "[u]nits capable of fuel switching have both economic and reliability benefits: allowing operators to purchase the cheaper of two fuels and have an alternate source of fuel if one source is interrupted or curtailed." In the Event, about 259 generating units, representing 34,518 MW, were capable of a secondary fuel option. About 53 of those generating units, representing 15,405 MW, attempted to switch from their primary fuel to their secondary fuel. The majority, 88 percent, representing 12,567 MW, were initially successful in switching fuel types. Approximately twelve percent of the fuel-switching-capable units, representing 2,749 MW, either failed to switch or experienced outages related to their use of alternate fuels after switching, due to various mechanical problems. Causes for switching failures included low gas supply pressure, gas\fuel oil leak, fuel pump issues, fuel oil divider failure, feedwater pump breaker failure, isolator failure, combustor purge line failure, high exhaust spread temperature, and solenoid freezing.

Figure 29: Location of Fuel-Switching-Capable Units in the Event Area



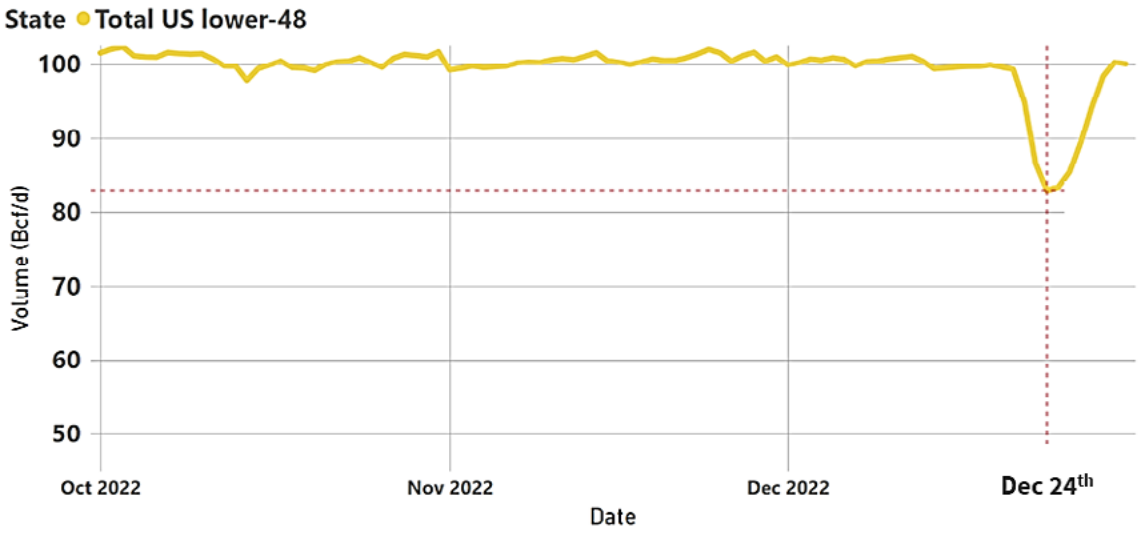
Of the generating units that successfully switched fuels, 73 percent, representing 11,767 MW, used gas as their primary fuel and oil\distillate oil as an alternate fuel. About 27 percent, representing 672 MW, used oil or distillate oil as their primary fuel and gas as an alternate fuel, and two units, representing 520 MW, used gas as their primary fuel and coal as an alternate fuel.

2. NATURAL GAS INFRASTRUCTURE OPERATING ISSUES RAPIDLY MOVE FROM PRODUCTION FACILITIES TO PIPELINES

a. Production declines begin

As Winter Storm Elliott moved across North America and temperatures decreased, dry natural gas[136] production in the lower 48 states declined. Production volumes on December 22 fell by 4,411 MMcf/day from the previous day and reached their largest daily decline between December 22 and December 23 – a difference of 8,368 MMcf/day. Dry natural gas production declined by 18 percent, falling to a low of 82.9 Bcf/day on December 24, 2022, as shown in Figure 30, below. Winter Storm Elliott primarily affected production in the Marcellus and Utica Shale formations. Together the Marcellus and Utica Shale formations create the Appalachian basin, which produced more gas in 2022 than any other area of the U.S., accounting for 29 percent of U.S. gross natural gas withdrawals (or 34.6 Bcf/d), according to EIA (see Figure 31, below). As shown in Figure 32 below, Marcellus Shale production volumes reached a low of 21,856 MMcf/d on December 24 (a 23 percent decrease compared to maximum production on December 19). Utica Shale production volumes reached a low of 3,017 MMcf/d on December 26 (a 54 percent decrease compared to maximum production on December 19).

Figure 30: Daily Dry Natural Gas Production (October - December 2022)[137]



136 "Dry natural gas" is produced by natural gas processing facilities that remove other hydrocarbons to produce what is known as "pipeline quality" dry natural gas that meets the heating content and other restrictions necessary for the safe operation of pipeline and distribution company facilities.

137 S&P Global Commodity Insights, ©2023 by S&P Global Inc.

Figure 31: Monthly U.S. natural gas gross withdrawals by region (January 2012 - December 2022)

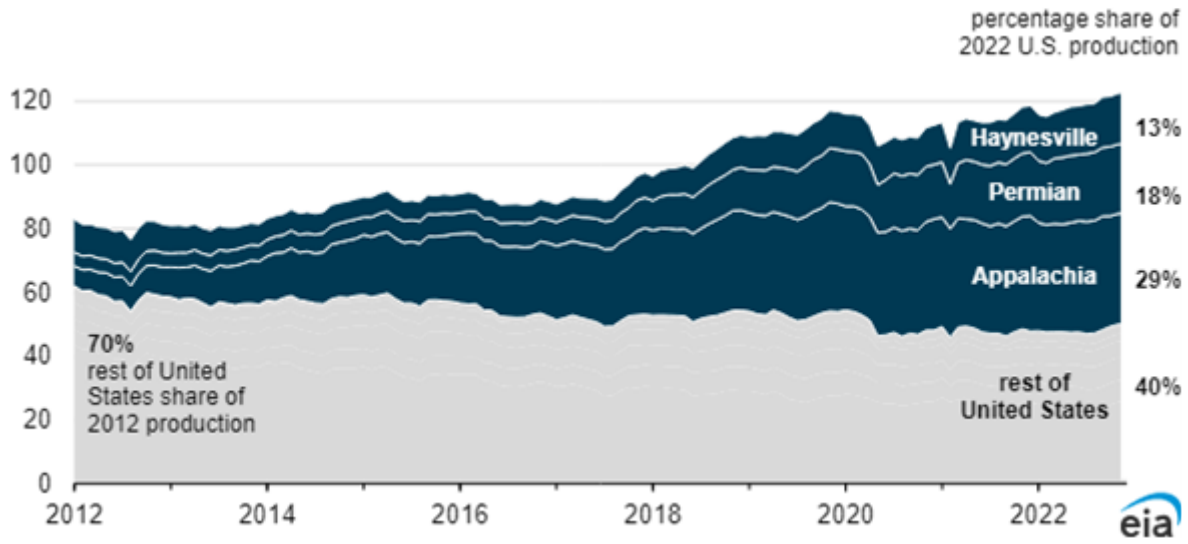
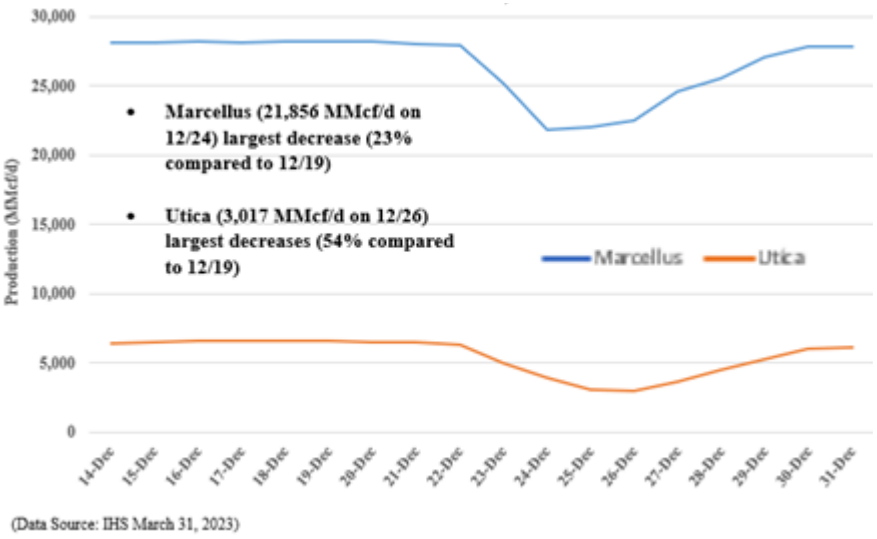


Figure 32: Natural Gas Production - Marcellus and Utica Shale Basins, December 14 – 31, 2022



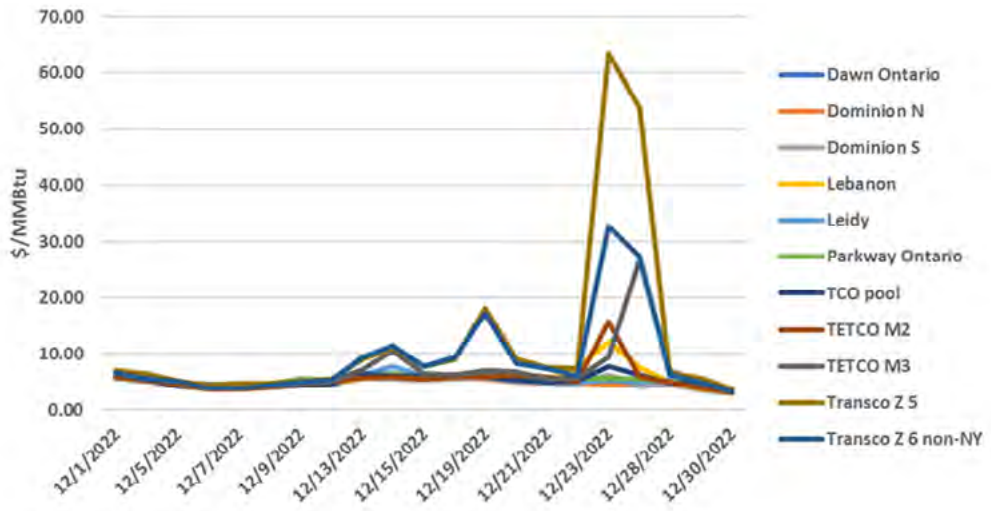
All but one natural gas producer identified freeze-offs as the primary cause of production declines, including frozen production equipment as well as wellhead freeze offs. Seven of the ten reporting producers identified downstream issues[138] as a significant driver of production declines. Downstream issues included outages in gathering systems, compressors, and processing plants, as well as one pipeline that could

138 Some producers also own and operate gathering lines/facilities, others deliver their production to gathering systems owned by others. Thus the categorization of "downstream" may not be consistent or limited to gathering systems.

not take gas from certain producers,[139] which caused idling of producer equipment. The idling of producer equipment then exacerbated freezing of production equipment and caused further reductions in natural gas production. Poor road conditions, which prevented personnel and, in some cases, water hauling trucks, from reaching remote production sites were also identified as an issue, although not as commonly as during Winter Storm Uri.[140]

These natural gas losses from critical natural gas production areas, in conjunction with increased demand, caused prices to increase dramatically in natural gas markets. For example, natural gas prices for Transco Zone 5, which extends from the Georgia-South Carolina border to the Virginia-Maryland border, increased more than eight-fold for trading on December 23 as compared to December 21. See Figure 33, below. Higher price levels can have a cascading effect in the marketplace, as natural gas pipelines may calculate their OFO penalties by pricing the penalty as a multiple of the natural gas market price. As a result, a shipper that is out of balance on a pipeline may choose to pay higher market prices for natural gas to avoid paying penalties; this in turn produces higher penalties and adds to the incentive to buy ever more expensive natural gas.[141]

Figure 33: S&P Global Market Intelligence Day-Ahead Natural Gas Prices for Northeast Region – Non-NY/NE for December 2022[142]



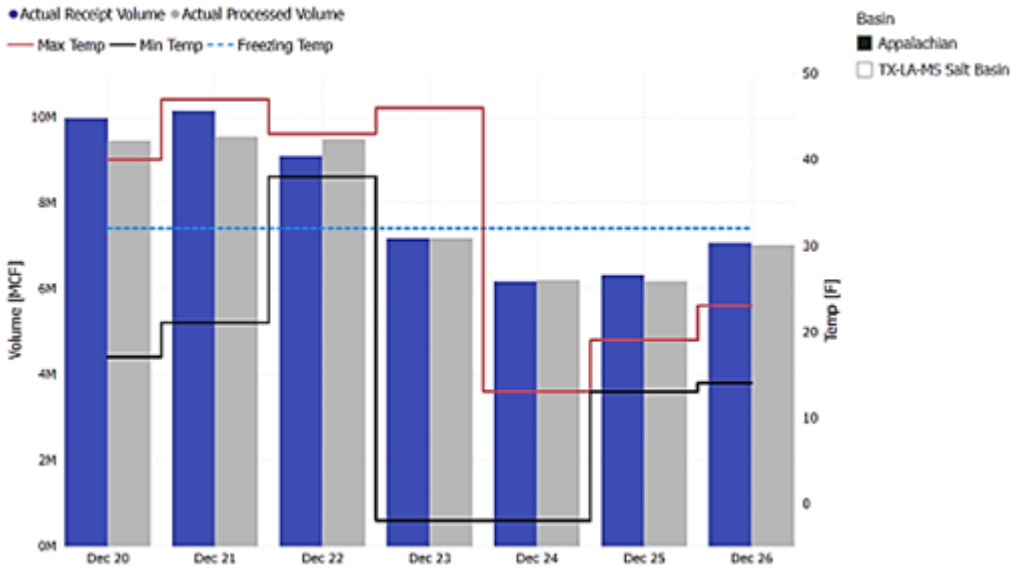
139 One pipeline stated that leading up to and on the evening of December 23, it started to pack its lines in preparation for high demand on December 24. The high pressure temporarily prevented producers from being able to move their gas onto the pipeline. The same pipeline also had a lag in demand load the morning of December 24, causing pressures to remain high, which exposed producers further to freezing vulnerabilities as they could not move their supply onto the pipeline system at that time.

140 *See* Analysis, section IV.C.2., for more examination of the causes of production losses.

141 Natural gas traders have explained the exacerbating effect of potential penalties during scarcity events during previous extreme cold weather events. The Team did not interview traders in the Event about this issue, although the same preexisting conditions of scarcity and critical notifications with potential for penalties existed during the Event as existed during previous events.

142 Source: S&P Global Market Intelligence Capital IQ Pro. © 2023 S&P Global Market Intelligence (and its affiliates, as applicable) (individually and collectively, "S&P"). Reproduction of any information, data or material, including ratings ("Content") in any form is prohibited except with the prior written permission of S&P. S&P does not guarantee the accuracy, adequacy, completeness, timeliness or availability of any Content and is not responsible for any errors or omissions (negligent or otherwise), regardless of the cause, or for the results obtained from the use of such Content. In no event shall S&P be liable for any damages, costs, expenses, legal fees, or losses (including lost income or lost profit and opportunity costs) in connection with any use of the Content.

Figure 34: Natural Gas Processing Facilities - Receipt Volume (December 20 – 26, 2022)



b. Processing and Pipeline Operating Issues

The extreme low temperatures beginning December 22-23 caused natural gas demand to increase at the same time that the volume of gas received by processing facilities declined, as illustrated in Figure 34.

Some processing companies said that they did not receive the full contracted amount of gas supply from producers, though they reported that they generally processed the gas they received.

On December 23 and 24, the strained operating conditions due to gas supply shortages experienced across the pipeline network were further exacerbated by equipment issues faced on certain pipelines. Natural gas pipeline facilities experienced 19 equipment issues which directly affected shippers, such as GOs/GOPs and local gas distribution companies. The largest reported cause of pipeline equipment issues was weather/freezing issues, followed by mechanical issues. The cold temperatures caused valves and compressor units at varying locations along the pipeline system to freeze, reducing or preventing the flow of gas through these facilities (see Figure 35, below). These issues caused instances of reduced natural gas pressure and 14 declarations of force majeure on certain pipelines which directly affected shippers (see Figure 36, below). Pipeline operators issued force majeures (which curtailed firm and interruptible gas transportation) to inform shippers that an event outside of their ability to reasonably foresee would affect all or a portion of the gas scheduled to flow through a segment of the pipeline system. Two pipelines issued a total of seven force majeures which affected a total of 156 firm shippers due to freezing issues, mechanical issues and reduced supply at seven compressor stations.

Eight of the fifteen interstate pipelines surveyed by the Team reported a total of 53 instances of commercial power loss at their facilities, totaling 466.5 hours during the Event. The outages averaged approximately nine hours in duration, although some lasted longer than three days.[143]

143 *See* section IV.C.4 for additional analysis.

Figure 35: Number of Pipeline-Reported Equipment Issues with Some Associated Flow Reduction

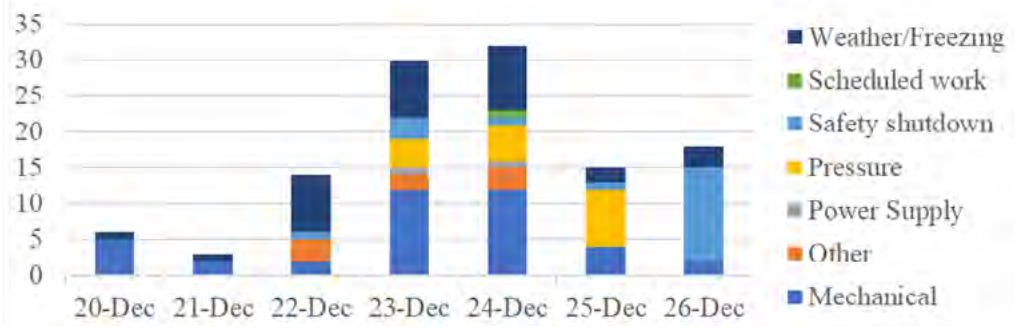
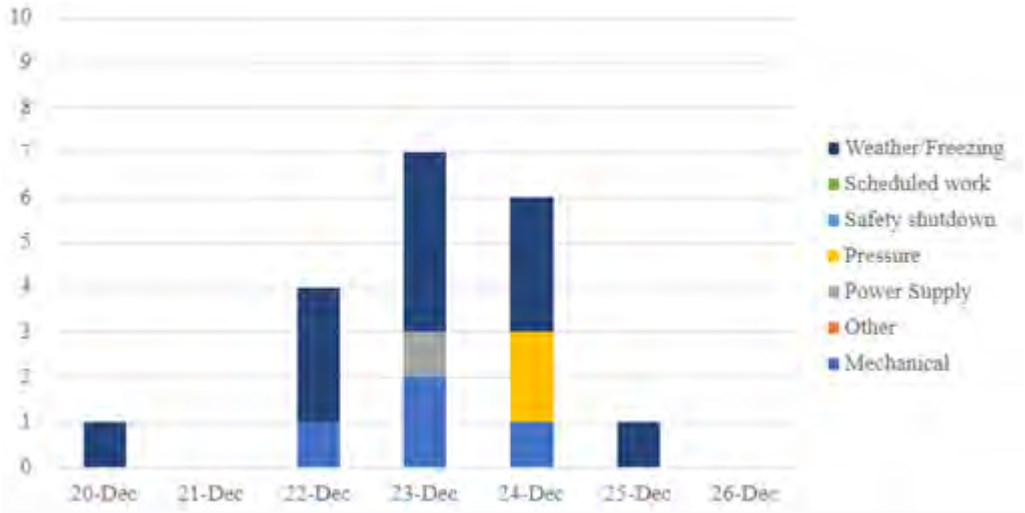


Figure 36: Number of Pipeline-Reported Equipment Issues Directly Affecting Shippers



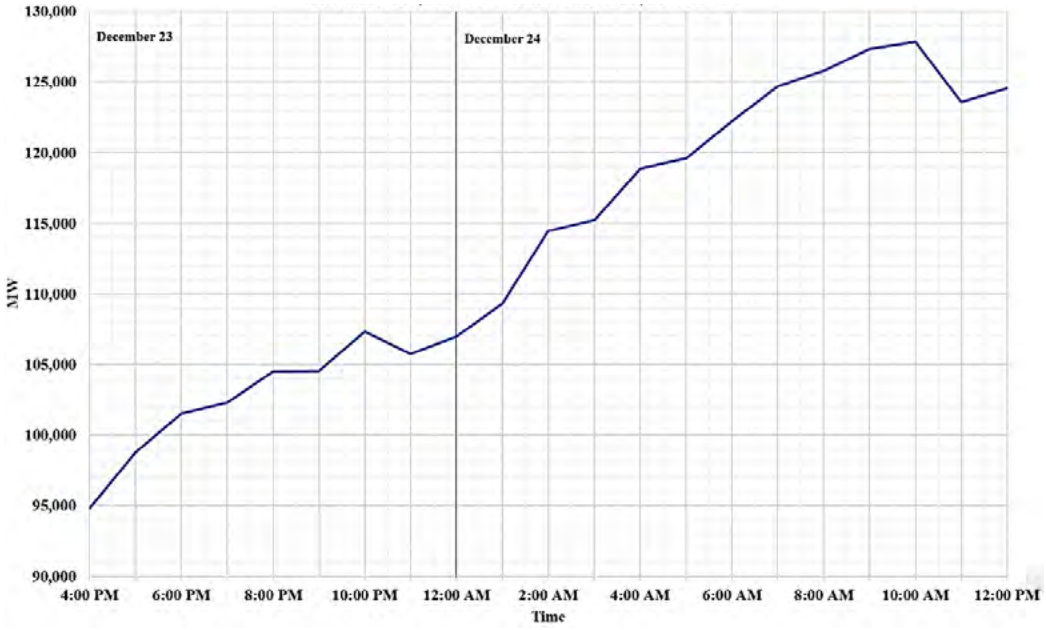
3. GRID OPERATORS' REAL-TIME ACTIONS AND COORDINATION DUE TO UNPLANNED GENERATION OUTAGES AND HIGH ELECTRICITY DEMANDS TO MAINTAIN BES RELIABILITY ACROSS A WIDE AREA

The breadth and scope of generation loss resulting from Winter Storm Elliott created unique and challenging conditions for grid operators. Figure 37, below, shows the total generation outages and derates impacting the Event Area during the most difficult period for the grid, the evening of December 23 and the morning of December 24. The graph includes both planned and unplanned generating unit outages; those existing at the beginning of the Event and those that occurred during the Event. Including generation that was already out of service,[144] a total of over 127,000 MW of generation was unavailable at the worst time, approximately 10 a.m. on December 24, which represented **18 percent** of the U.S. portion of the winter 2022-2023 anticipated resources in the Eastern Interconnection.[145]

144 Those units that were already out of service included generating units undergoing planned maintenance outages and those units that incurred forced outages before the Event, that had not yet returned to service during the worst point of the Event.

145 Based on data from NERC 2022-2023 Winter Reliability Assessment. *See* note 12. Without the generation that was already out of service, the outages represented 13 percent of the U.S. portion of the winter 2022-2023 anticipated resources in the Eastern Interconnection.

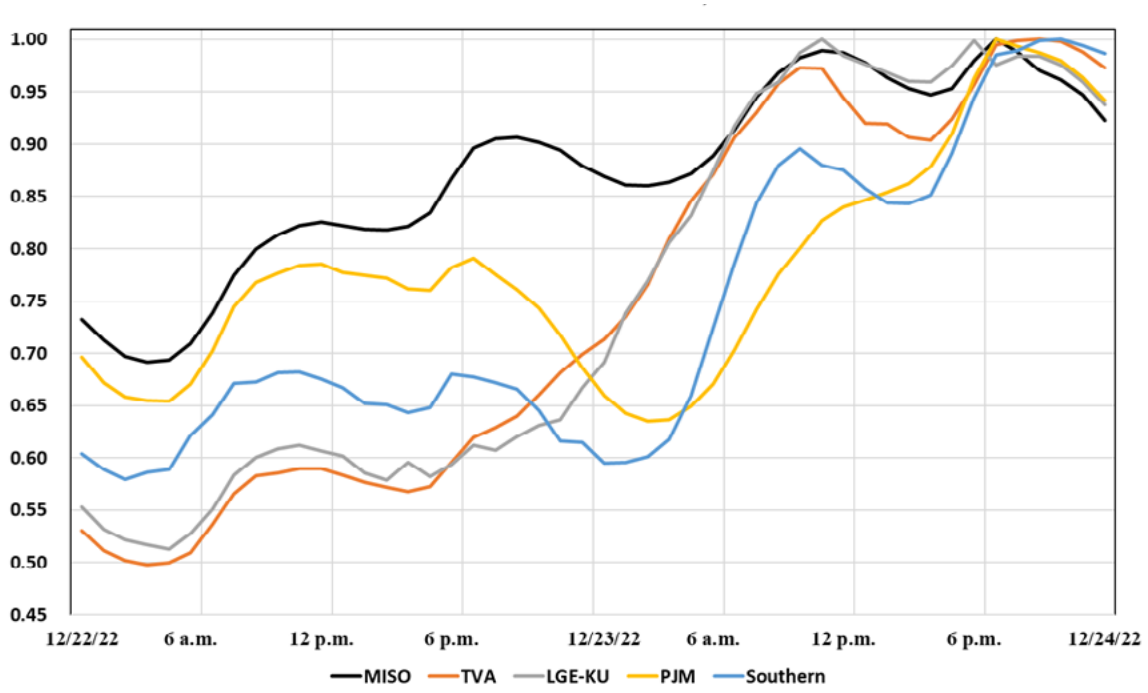
Figure 37: Total Estimated Unavailable Generation in U.S. Portion of Eastern Interconnection[146] – December 23, 4:00 p.m. to December 24, 12:00 p.m.



Due to the breadth and scope of generation loss during the Event, several BAs encountered the same set of circumstances during the day and into the evening on Friday, December 23: rapidly-increasing electricity demands due to the extreme cold weather and high levels of unplanned generation outages and derates. Figure 38, below, shows how dramatically BA electricity demands increased from Thursday morning, December 22, to Friday evening, December 23, and explains why BAs had little energy to share with other BAs experiencing EEAs. Other than Southern BA, which experienced its winter peak load the morning of December 24, the BAs shown *all* experienced their peak demands on the evening of December 23.

146 Total generation shortfall is estimated, since it does not include potential planned and unplanned generation outages that may have existed for the Florida peninsula during the timeframe, since analysis of that region was not included in the targeted scope of the inquiry.

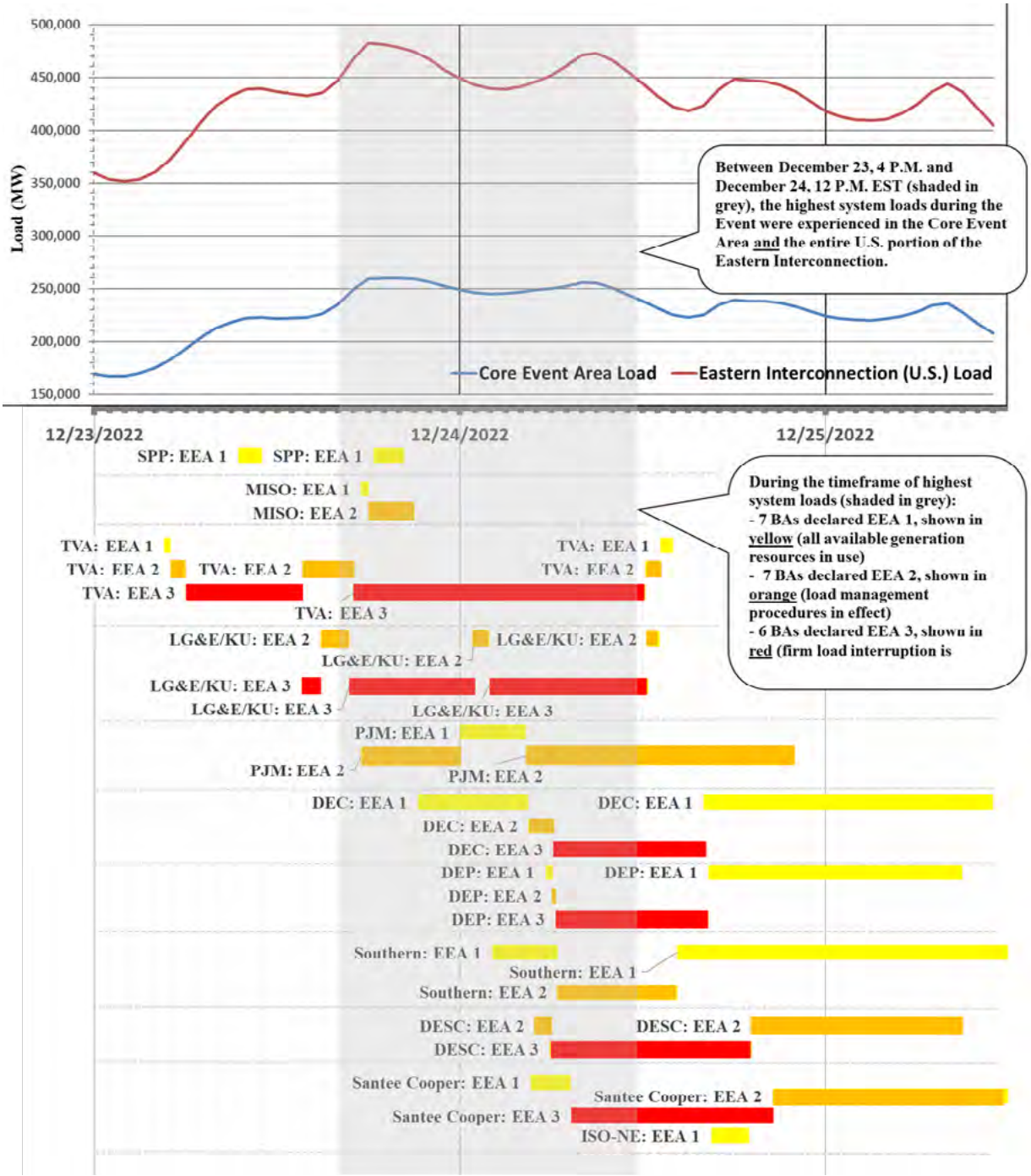
Figure 38: BA Normalized Hourly System Load Patterns for December 22-23, 2022 (Normalized to December 23 Peak Loads Experienced)[147]



As demand grew and supply shrank over December 23 and 24, electric grid entities took proactive measures to protect their footprints by declaring conservative operations actions. By the end of December 24, almost all the BAs impacted by Winter Storm Elliott were forced to implement EEA procedures. See Figure 39, below. The gray shaded area represents the timeframe of highest system loads in the Core BAs.

147 DEC, DEP, DESC and Santee Cooper BAs (not shown in the figure), which are located further east, likewise experienced their system peak loads on Saturday, December 24, and experienced a similar pattern of increasing load.

Figure 39: Core Event Area and Eastern Interconnection (U.S.) System Loads and Event Area Energy Emergencies Timeline – December 23 12:00 a.m. to December 25, 12:00 p.m.



The widespread and simultaneous energy emergency conditions greatly reduced the BAs' ability to obtain power from neighboring entities.

Note regarding "N-1"

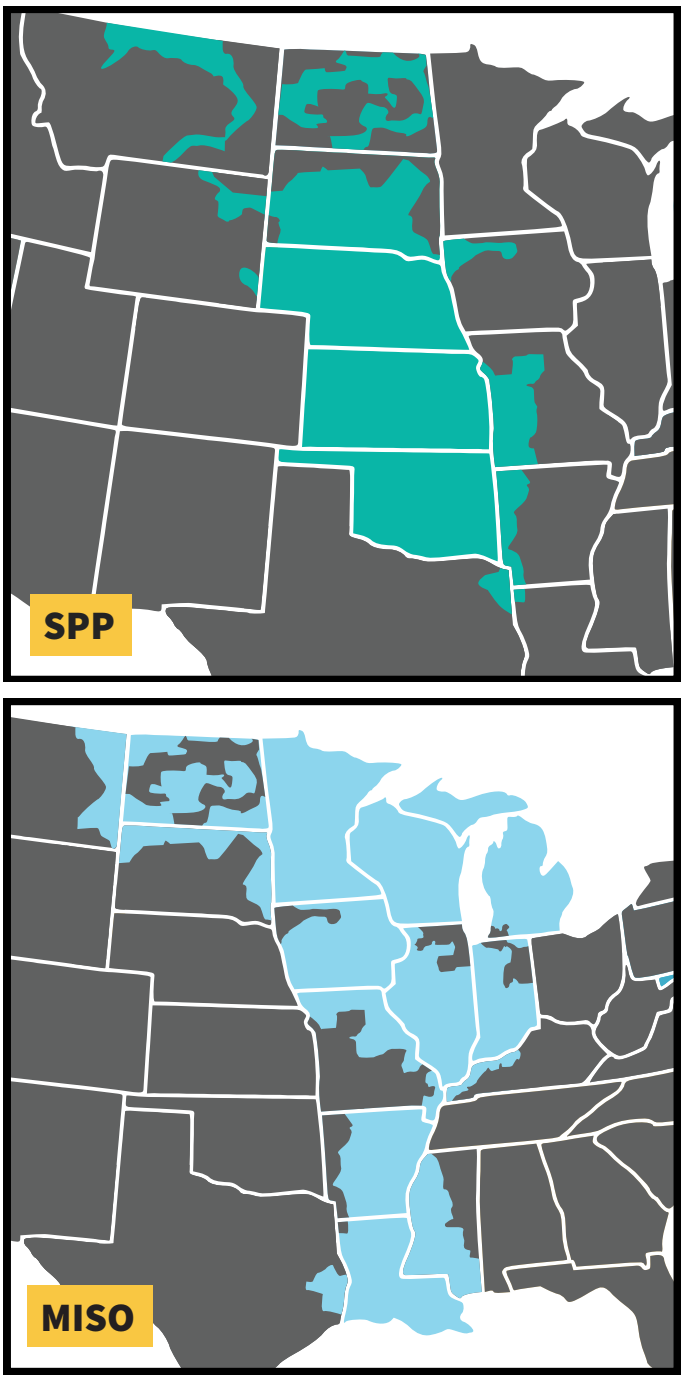
As described above in Section III, there were numerous coincident unplanned generator outages and derates. This meant the grid operators were operating a grid that was far from the N-1 planning criteria (e.g., loss/outage of one generator) used to plan the transmission grid.[148] Instead they were experiencing an **N-"numerous"** condition[149] at any given time during the Event. The AC transmission system that comprises the BES relies heavily on online generation for reliable operation. Having sufficient online generators enables more effective congestion management, by facilitating AC power transfers while allowing transmission constraints to remain within system operating limits, as well as enabling system stability and the maintenance of normal thermal and voltage limits.

a. Thursday, December 22: Elliott begins to impact U.S. portion of Eastern Interconnection

- Winter Storm Elliott begins to impact westernmost part of U.S. Eastern Interconnection
- SPP and its TOPs first face operating challenges

SPP was the first BA in the U.S. portion of the Eastern Interconnection to experience Elliott's extreme cold and high winds, although its footprint did not incur more severe emergency conditions as others did in Elliott, or as SPP had experienced in Winter Storm Uri. SPP noted that the storm front moved more quickly than in 2021 and swept from northwest to southeast.[150]

Figure 40: SPP and MISO Footprints



148 For more information on transmission system planning performance, *see* NERC Reliability Standards, Transmission Planning (TPL), TPL-001-5.1 - Transmission System Planning Performance Requirements. RSCompleteSet.pdf (nerc.com).

149 1,702 individual generating units experienced outages, derates, or failures to start for the entire Event Area from December 21 to 26, 2022.

150 *See* SPP Report at 21.

SPP reported that it did not experience an increase in unplanned transmission outages. SPP largely escaped the heavy snow and freezing precipitation that most threatens transmission elements. However, its system operators were challenged with escalating unplanned generation outages and electricity demands on December 22, before grid operators to the east like PJM experienced the same conditions. In addition, a localized area on its transmission grid created operational challenges.

Between 1:00 and 7:00 p.m. on December 22, SPP experienced multiple unplanned generating unit outages totaling 1,400 MW in the eastern portion of SPP's footprint in a very short time frame between 1:00 p.m. and 7:00 p.m. As these unplanned generation outages were occurring, SPP was on its way to setting a record for winter seasonal electricity demand of 47,157 MW, which occurred at 6:27 p.m.[151] In addition, SPP's eastern area grid conditions were further strained by a planned transmission line outage near the 1,400 MW of generating unit losses. The transmission outage, which began in September 2022, was scheduled for completion in January 2023 (a planned upgrade to increase the transfer of energy from the central portions of the SPP system eastward into the area most impacted during the Event).[152] The combination of events contributed to increased transmission congestion and low voltages on the 345 kV and 161 kV networks in southwest Missouri. Local transmission operators in the SPP footprint implemented 29 MW of load shed at 10:00 p.m. on December 22 in the Branson, MO area to alleviate the low transmission voltages.[153] After hydroelectric generation in the area was restored to provide voltage support and voltages recovered, transmission operators were able to restore the load by 12:00 a.m. on December 23.

b. Morning of Friday, December 23: BES reliability conditions worsen overnight

- Extreme cold weather moves eastward
- MISO and TVA operators faced with rising unplanned generation outages coupled with high electricity demands
- Grid operator coordination to manage transmission constraints
- SPP's ability to maintain reserves challenged during early morning
- SPP and TVA declare energy emergencies
- TVA declares EEA 3, sheds firm load[154]

MISO. As the extreme cold weather moved eastward, throughout the early morning hours of December 23, and as unplanned generation outages and failures to start began in the MISO South region, MISO found that its real-time MISO South system load exceeded its forecast. Pursuant to its security constrained economic dispatch, MISO's north-to-south power transfer, known as its Regional Directional Transfer (RDT),[155] increased to supply more power to meet its southern load (see Figures 41 and 42, below).

151 All times stated within the Report, unless otherwise specified, are in Eastern Standard Time (EST). If the entity is located in the Central Time Zone, the times were converted to EST.

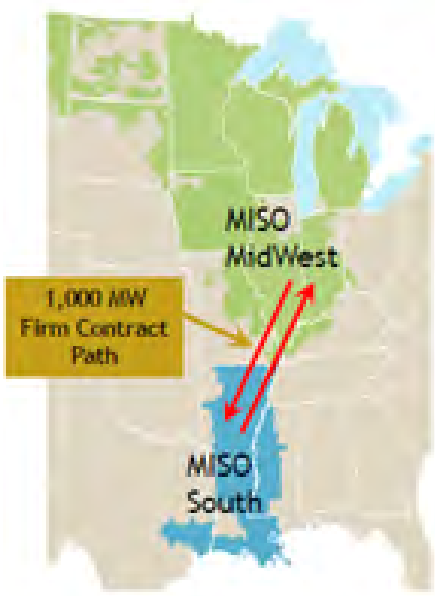
152 SPP Report at 28.

153 SPP performed a post-event analysis and found that if during Elliott the planned transmission line outage (the line described earlier that was outaged from September 2022 to January 2023) had been back in service, along with an additional newly-constructed transmission line and a then-unavailable capacitor bank, it would have reduced low voltage limit exceedances to less than ten times as many (from 292 low voltage limit instances to only 25 low voltage limit instances).

154 Red text references EEAs experienced by BAs.

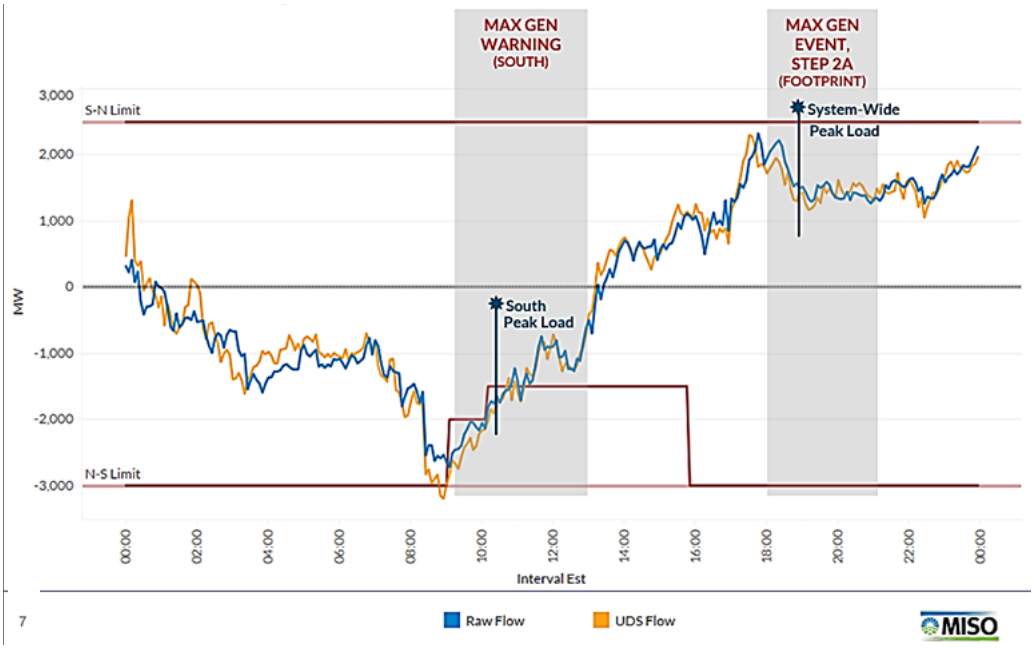
155 MISO limits the amount of power it transfers intra-market via its RDT, referred to as its Regional Directional Transfer Limit (RDTL), under a joint coordination agreement with SPP, AECI (Associated Electric Cooperative, Inc.), TVA, LG&E/KU, Southern and PowerSouth, to 3,000 MW from north-to -south (1,000 MW firm and 2,000 MW non-firm, as-available) and 2,500 MW from south-to -north (1,000 MW firm and 1,500 MW non-firm, as-available). While the total AC tie line capacity, calculated by adding the total capacity of all tie lines between the BAs at issue, may indicate a large transfer capacity, the actual ability to transfer power will be dependent on system conditions at the time of transfer, including ambient temperatures, generation outages and dispatch, transmission outages and derates, all of which drive actual power flows on transmission lines and can limit available transfer capability.

Figure 41: Illustration of MISO's Regional Directional Transfer



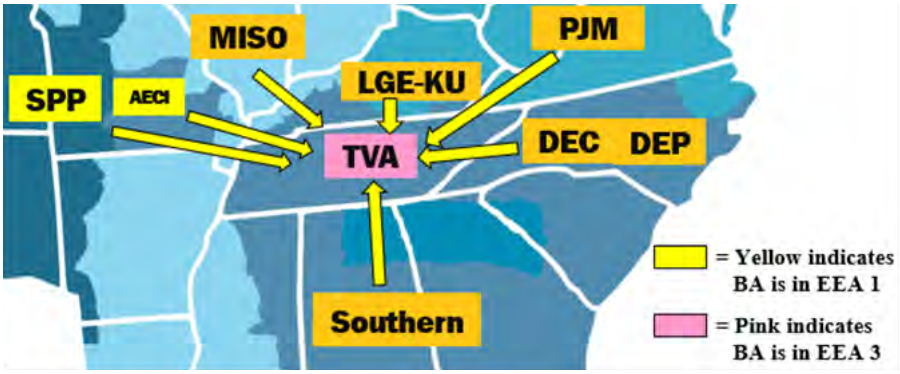
At 9:00 a.m., based on SPP's observed system conditions, SPP asked MISO to reduce its RDT limit (north-to-south power transfer) to 2,000 MW, and approximately an hour later, asked MISO to further reduce it to 1,500 MW. MISO complied with both requests, reducing the RDT, as shown in Figure 42, below. MISO and SPP coordinated to release the RDT reduction later that afternoon.

Figure 42: MISO Regional Directional Transfer (RDT) Flow,[156] December 23, 2022



156 Positive flow is MISO South-to-North flow; negative flow is MISO North-to-South flow. Image used by permission of MISO.

Figure 43: Status of TVA's Neighboring BAs for Potential of Scheduling Import Power, Morning of December 23



Throughout the morning of December 23, MISO's electricity demand continued to increase along with unplanned generation outages within its own footprint. At 9:15 a.m., MISO implemented a "Maximum Generation Warning" in MISO South.[157] MISO's entire BA footprint electricity demand also escalated throughout the morning of December 23, with morning and evening hour-average peak loads close in magnitude to one another. For the hour-ending 11:00 a.m., MISO's hourly load was 104,804 MW, 99 percent of what its evening peak hourly load would soon be. The combination of high system loads and higher-than-expected forced generation outages throughout the day eventually led MISO to declare an energy emergency at 5:30 p.m., as described further below.

SPP. SPP RC faced local transmission issues the morning of December 23. A combination of unplanned generating unit outages and transmission outages in the eastern SPP footprint contributed to depressed local voltage conditions in southwestern Missouri/northeastern Oklahoma.[158] In addition to these challenges, SPP BA faced operating reserve shortages to meet its early morning peak system load, which by hour-ending 10:00 a.m., had reached 96 percent of its previous-evening record-breaking winter peak load. From 9:27 a.m. to 11:00 a.m. on December 23, SPP declared EEA 1, and curtailed approximately 600 MW of non-firm exports due to its own operating reserve shortfalls, preventing SPP from being a source of power for neighboring BAs during that time. At 11:33 a.m., SPP declared a transmission operating emergency in response to abnormally large numbers of post-contingency system constraints that were breached due to system conditions. According to SPP, the purpose of its transmission operating emergency declaration was to ensure internal and neighboring entities were aware of the abnormal system conditions in its footprint. At 4:09 p.m., SPP terminated the transmission operating emergency. SPP did not need to implement pre-contingent load shed, but rather relied on post-contingent plans put in place by the TOPs within its footprint. At no time during the transmission operating emergency did SPP have an interconnection reliability operating limit (IROL) exceedance.

TVA. When TVA's available generation resources rapidly decreased the morning of December 23, TVA declared EEA 1 and 2 by 5:38 a.m., followed by EEA 3 at 6:12 a.m.

157 MISO's Maximum Generation Warning declaration, in addition to calling for all generation resources to be committed to meet load, called for its members to schedule in (to the MISO footprint) external resources, and to curtail non-firm exports.

158 AECI, a transmission operator and BA located in Missouri and northeastern Oklahoma, contacted TVA (its Reliability Coordinator) and other neighboring entities at approximately 8:30 a.m. to request voltage support for its southwestern Missouri/northeastern Oklahoma service area, which was affected by SPP's unplanned outages in the area. AECI declared a Transmission Emergency at 9:05 a.m., and prepared to shed load, but did not need to shed load due to improved conditions.

In addition to taking the emergency actions, TVA sought emergency energy from its neighboring BAs.

Initially, TVA received emergency energy imports from MISO, DEC, Southern, and PJM (depicted in Figure 43, above). These imports were sufficient to avert the need for TVA to order firm load shed for a time. By 9:38 a.m., PJM needed to curtail half (250 MW) of its emergency power delivery to TVA due to an SOL condition – a portion of PJM's emergency energy interchange schedule actual power flow caused a transmission facility within the PJM footprint to reach its emergency flow limit in real time.[159] Despite tightening conditions on the MISO system as the morning progressed, MISO maintained steadily increasing exports to TVA throughout the day. At 10:15 a.m., TVA was able to obtain 243 MW from its Reserve Sharing Group (from LG&E/KU), which offset a portion of the PJM reduction in emergency energy.[160] By 10:31 a.m., TVA operators ordered firm load shed of approximately five percent of its peak system load (estimated to provide over 1,500 MW in load reduction) in response to escalating unplanned generation outages (now at 6,500 MW, an increase of 2,000 MW since 5:00 a.m.) and rising electricity demand. At the same time, TVA's available emergency purchase power had decreased, and other neighboring BAs were unable to provide emergency energy.[161]

This was the first time in TVA's history that TVA ordered firm load shed. TVA would need to shed firm load a second time due to even worse conditions across the entire Event Area by early morning December 24. A little over two hours later, at 12:43 p.m., TVA was able to order restoration of firm load due to an increase in TVA's own available generation resources beginning early afternoon, and a limited increase in import power. These conditions enabled TVA to temporarily improve to EEA 2 for approximately three hours; it later returned to EEA 3 as the evening peak approached with energy supply conditions worsening.

c. Friday Evening, December 23: BES conditions continue to worsen

- Extreme cold weather now expands across LG&E/KU and PJM footprints
- Friday evening peak loads are highest for several BAs in Event Area
- Energy emergencies declared by SPP, TVA, MISO, LG&E/KU, and PJM
- MISO declares two local transmission emergencies, no load shed needed
- SPP returns back to EEA 1, challenges maintaining reserves
- TVA returns to EEA 3, continues load management measures and customer appeals for voluntary load reduction
- PJM and MISO declare EEA 2, implement load management measures
- LG&E/KU declares EEA 3, sheds firm load

During the day and into the evening hours on Friday, December 23, several BA footprints experienced the same challenging combination: rapidly increasing electricity demands due to the extreme cold weather (as illustrated in Figure 38, above), plus high levels of unplanned generation outages. For some BAs, the unplanned generation outages continued to increase at a rapid rate as illustrated earlier in Section III.

LG&E/KU. With LG&E/KU's system load already at 96 percent of its new all-time record winter peak load which occurred December 23, coupled with significant unplanned generation derates, by 1:36 p.m. on December 23, LG&E/KU declared EEA 3, but recovered to an EEA 2 by 2:52 p.m. At 4:29 p.m., PJM BA curtailed

159 High level of transmission facility loading or flow was further exacerbated by significant levels of unplanned generation outages (an N – "numerous" condition) combined with increasing electricity demands, in the region. PJM took appropriate actions to maintain the facility loading within its limit, maintaining BES reliability.

160 Again at 11:50 a.m., LG&/KU continued its assistance to TVA by extending provision of 243 MW Reserve Sharing to TVA.

161 As of 9:42 a.m., AECI BA was also at EEA 1. SPP, though not a neighboring BA to TVA but a potential source of power via wheeling through AECI or MISO, was also in an EEA 1 during this period.

the 400 MW import power due to experiencing rapidly increasing levels of unplanned generation outages coincident with increasing system load in its own footprint. With import power curtailment, at 4:29 p.m., LG&E/KU requested emergency energy from its contingency reserve sharing group. TVA, although in EEA 2 at the time, supplied LG&E/KU with 400 MW of emergency energy. At 4:45 p.m., LG&E/KU re-entered EEA 3. However, following TVA's return at 5:18 p.m. to an EEA 3 condition, at 6 p.m. it could no longer spare the 400 MW of emergency power to LG&E/KU. With the loss of its import power schedules to offset the generation derates, and its increasing system load conditions, LG&E/KU began over 300 MW firm load shed at 5:58 p.m. Over the next several hours, LG&E/KU was able to incrementally restore firm load that was shed as system loads decreased after its evening peak, and by 10:11 p.m., restored all firm load.

PJM. As the severe cold weather moved into the PJM area, loss of generation resources and load increases both exceeded their forecast amounts. As these factors increased throughout the Event, PJM needed to take emergency actions to mitigate the impact to its system. Earlier in the Event, before Winter Storm Elliott reached its footprint, PJM exported energy to neighboring BAs to its west that were short on capacity. However, as the storm moved in and the generation losses and loading increased on the PJM system, by 5:30 p.m. on December 23, PJM itself needed to declare EEA 2, invoking load management measures (e.g., demand response). PJM also reduced its energy exports, no longer able to be a source of power for BAs in need due to its own operating reserve shortfalls. According to PJM operators, PJM had barely avoided load shedding on December 23.[162]

Figures 44 and 45,[163] below, show how PJM's reserves declined throughout the day on December 23, driven heavily by unplanned generation forced outages in its footprint.

162 Affidavit of Paul McGlynn in Essential Power OPP, LLC et al. v. PJM Interconnection, LLC, Docket No. EL23-53-000, 23-54-000, 23-55-000 (hereafter "McGlynn Affidavit"), at ¶¶ 10, 34, 36-40, 48-51, 59.

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Figure 44: PJM Unplanned Generation Outages and Reserves, December 21-26, 2022

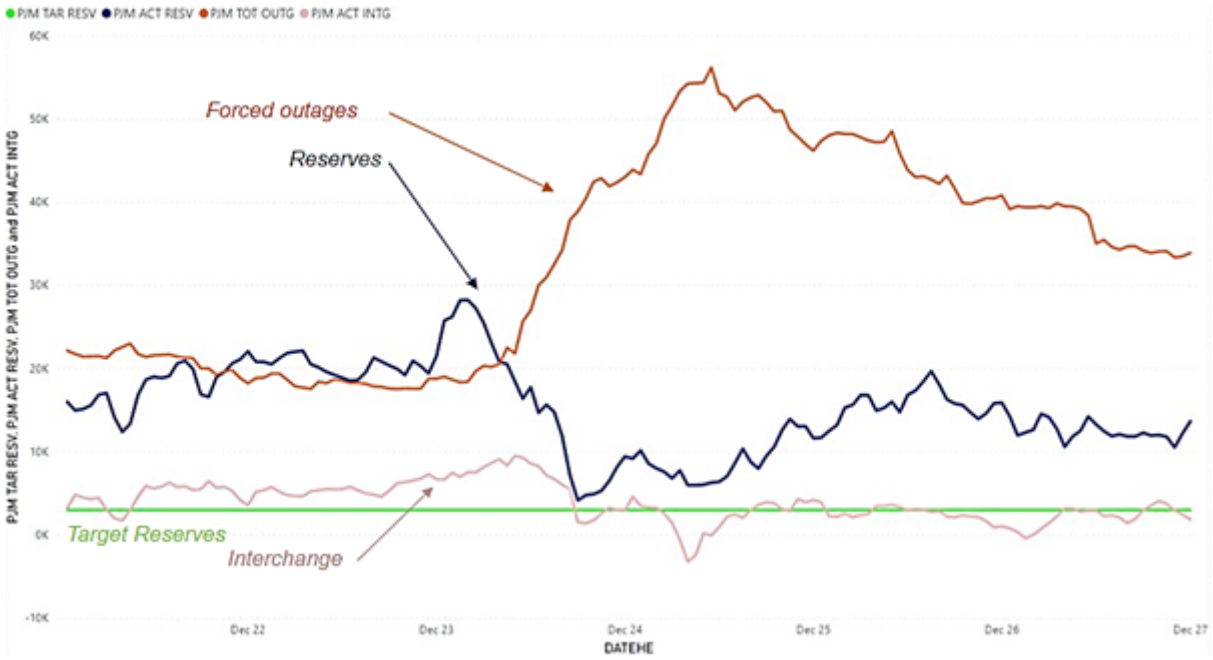


Figure 45: PJM BA Synchronized Reserves, December 23, 2:00 p.m. – December 24, 12:00 a.m.

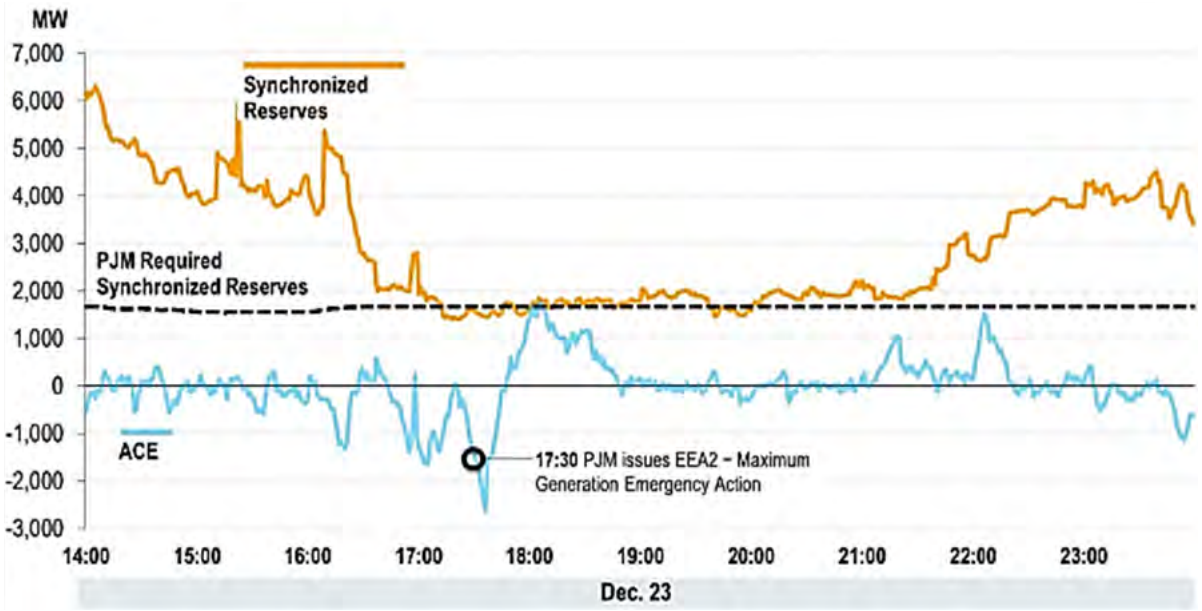
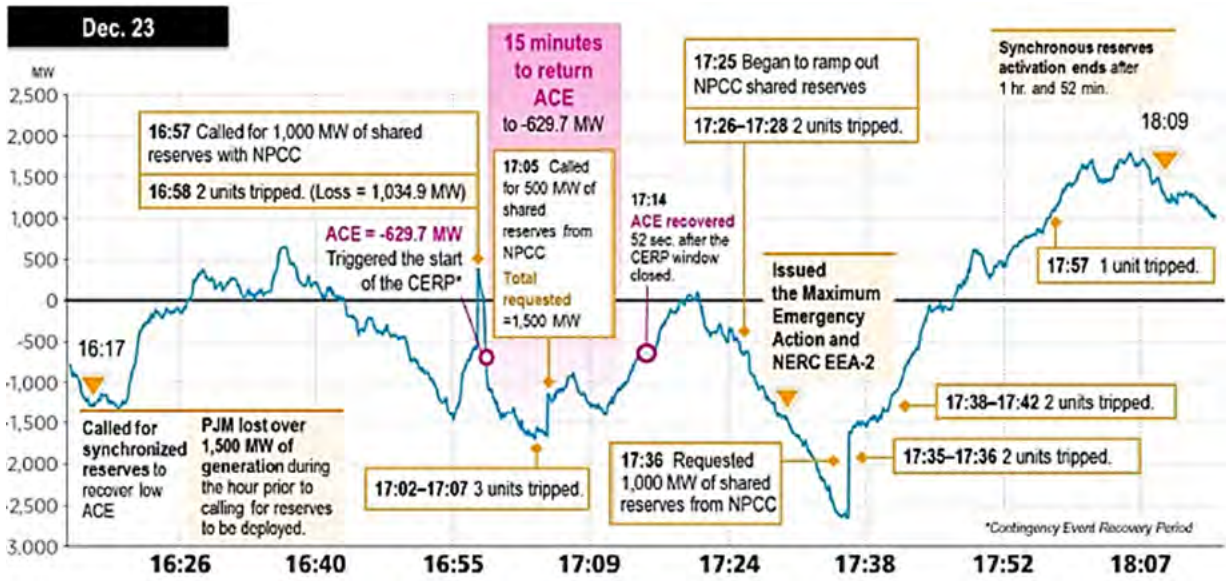


Figure 46: PJM BA Area Control Error (ACE) and Actions Timeline, December 23, 4:15 p.m. – December 24, 6:15 p.m.



As shown in Figure 46[164] above, PJM was able to benefit from a Simultaneous Activation of Ten-Minute Reserve (SAR) agreement with the Northeast Power Coordinating Council (NPCC). The SAR Agreement allowed PJM to call on reserves of up to 1,500 MW during the Event. PJM requested SAR assistance five times between December 23 and 24, all of which were due to stressed system conditions. PJM remained in EEA 2 until midnight December 23, narrowly avoiding the need that evening to declare EEA 3 and shed firm load. By midnight, conditions improved enough for PJM to downgrade to EEA 1, but that was short-lived, as described further below.

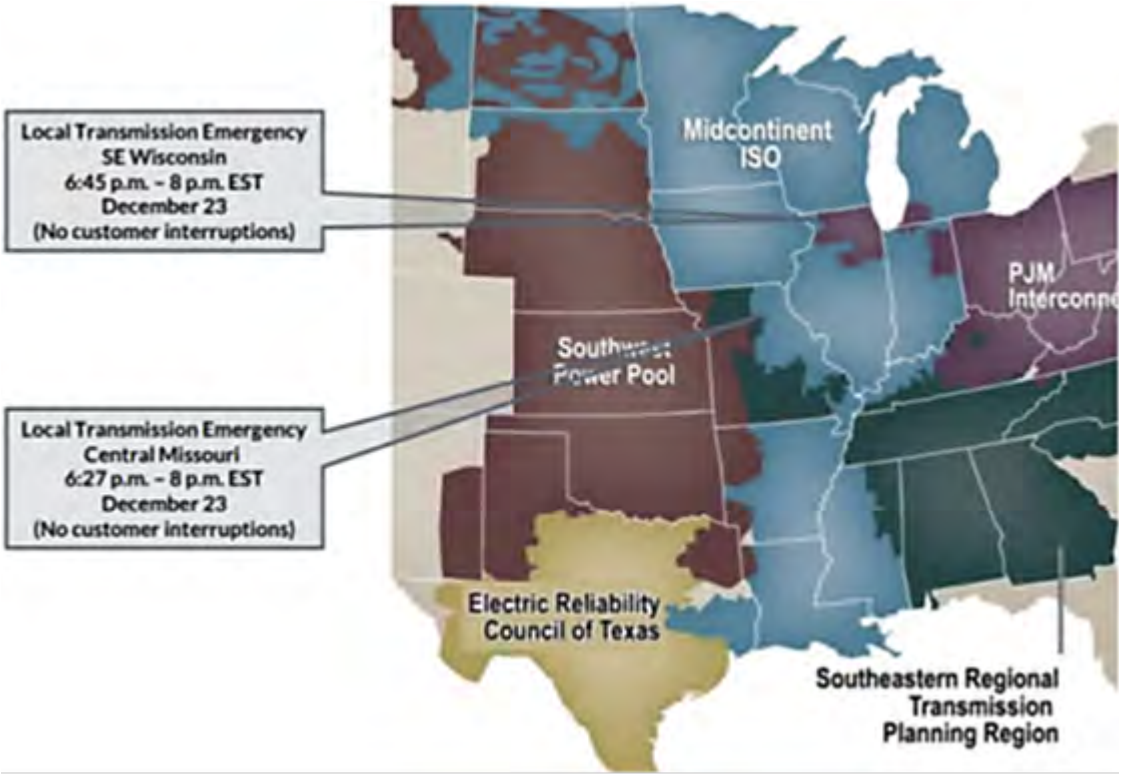
MISO. System electricity demand levels remained elevated throughout the day on December 23. This was not only true for its south region, which, as described above, contributed to MISO invoking a maximum generation warning, but also for its entire footprint. Following MISO's morning peak load on December 23, demand levels remained at or above 95 percent of the Winter Storm Elliott peak demand that MISO would experience that evening. Those high loads, coupled with unplanned generation outages increasing throughout the afternoon, led MISO to declare EEA 1 at 5:30 p.m. and EEA 2 at 6:00 p.m., when load and generation losses did not improve. Similar to PJM, when MISO declared EEA 2, it implemented its demand response, which reduced the electricity demand in its footprint. MISO remained in EEA 2 until 9:00 p.m., when its electricity demand lessened.

During the evening of December 23, MISO RC operators declared two local transmission emergencies to help manage congestion on its system. As shown in Figure 47, below, on December 23, in southeastern Wisconsin, MISO established a post-contingent mitigation plan to avoid significant redispatch of generation within that local area. Also on December 23, in eastern Missouri, MISO declared a local transmission emergency, which provided access to additional hydroelectric generation that was only available during emergency conditions.

164 This image is reproduced with the permission of PJM © PJM.

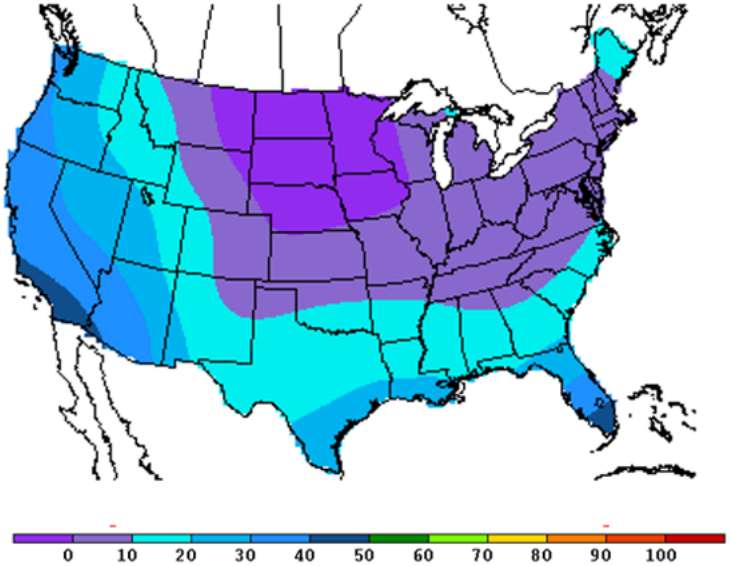
Finally, MISO declared a Transmission Loading Relief (TLR) 5[165] to manage transfers for a post-contingent constraint in southeastern Michigan, which was in effect from December 24 at 2:00 a.m. until 12:00 p.m. on December 26.

Figure 47: MISO Local Transmission Emergencies, Evening of December 23, 2022



165 Transmission Loading Relief (TLR) 5 is the highest level of Transmission Loading Relief that can be declared by a Transmission Provider. If system conditions warrant, a TLR 5 can enable the Transmission Provider to curtail a firm transmission reservation(s) to decrease the impact on an overloaded transmission facility. If a Transmission Provider curtails a Firm Transmission Reservation, it must curtail its own firm load on an equal basis.

Figure 48: December 24, 2022 Actual Minimum Temperatures – Lower 48



SPP. Just as in the morning, SPP BA was still facing operating reserve shortages to meet its December 23 evening peak system load, which by hour-ending 7:00 p.m., was already over 90 percent of December 22's evening record peak load and rising. The evening of December 23, SPP declared its second EEA 1 from 6:20 p.m. to 9:20 p.m. and curtailed approximately 1,100 MW of non-firm exports, which prevented SPP from being a source of power for BAs in need due to its own reserve shortfalls.

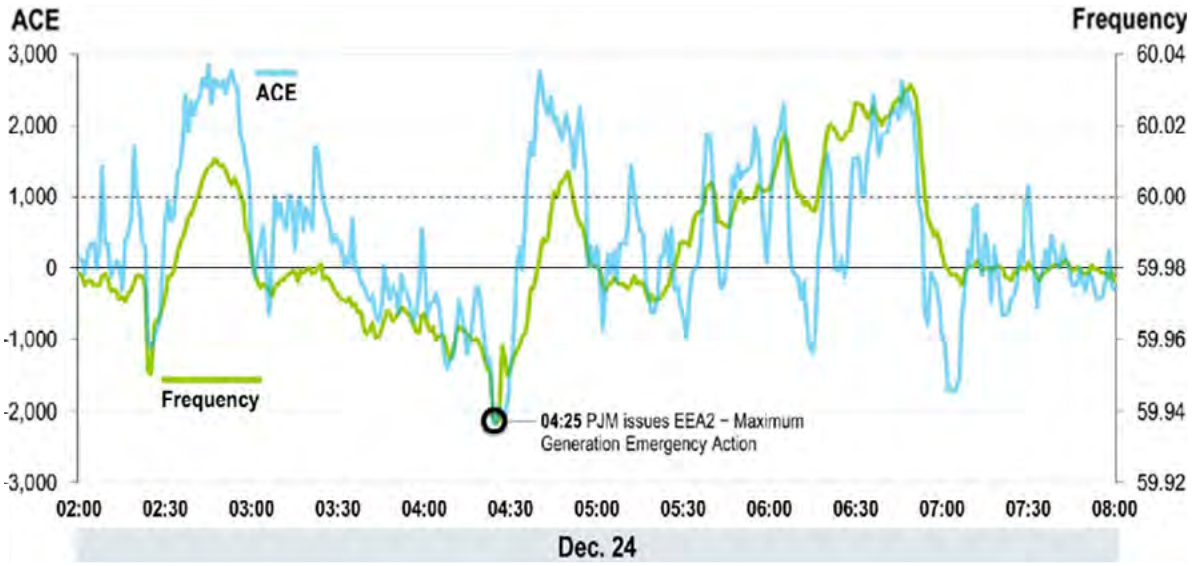
TVA. At 5:18 p.m., TVA returned to EEA 3 because neighboring entities such as Southern were dealing with their own energy emergencies by reducing their energy exports to TVA, and TVA's electricity demand was trending toward what would become its all-time record winter peak load later that evening. TVA, now at risk of shedding firm load, recalled the 400 MW contingency reserves that it was providing LG&E/KU at 6:00 p.m. This action, combined with later receiving emergency energy imports through their evening peak hours from DEC and Southern enabled TVA to avoid shedding firm load that evening. TVA would not be able to avoid load shed by the next morning. Figure 39, above, includes a timeline illustrating the Energy Emergencies declared by BAs on December 23.

d. Saturday Morning, December 24: Many simultaneous BES Energy Emergency conditions

- Extreme cold weather expands across southeastern U.S.
- Responsive reserves decline across the Core Event Area
- Simultaneous energy emergencies exist in TVA, LG&E/KU, PJM, DEC, DEP, DESC, Southern, and Santee Cooper
- PJM returns back to EEA 2, implements load management measures, and makes customer appeals for voluntary load reduction
- TVA, DEC, DEP, DESC, Santee Cooper BAs declare EEA 3, shed firm load
- Southern declares EEA 2, obtains emergency energy from Florida, implements load management measures to lower system load, did not need to shed firm load
- NYISO and ISO-NE impacts

Extreme cold weather continues – generation reserves continue to diminish. In the overnight hours heading into the morning of December 24, the extreme cold weather conditions accompanying Winter Storm Elliott eventually blanketed the southeastern U.S. all the way to the Atlantic Ocean, Figure 48, above).

Figure 49: PJM BA Frequency Plot and ACE Conditions, December 24, 2:00 a.m. – 8:00 a.m.



The pattern of unplanned generation outages and high electricity demands seen in the BA footprints described above continued overnight and into the morning of December 24 for BA footprints located in the easternmost region of the U.S. Forced outages and derates of generating units continued to diminish BA reserves during the early morning hours of December 24.

PJM. PJM began December 24 in EEA 1. As the PJM BA continued to experience significant unplanned generation outages and derates through the early morning hours as referenced in Figure 27, above, at 4:00 a.m. on December 24, PJM issued a call for voluntary conservation to last until 10:00 a.m. on December 25. PJM estimated that responses to its call for conservation helped to reduce load beginning at about 7:15 a.m.

At 4:20 a.m., PJM BA needed to return to EEA 2. At 4:23 a.m., PJM BA had a low ACE event,[166] and called for over 1,000 MW of synchronized (responsive) reserves from its reserve-assigned generation. Only 169 MW of synchronized generation reserves responded (a 16.8 percent response rate).[167]

As shown in Figure 49,[168] above, at 4:25 a.m., PJM BA issued EEA 2, and called for Maximum Generation Emergency Action. PJM also used load management measures during its EEA 2, to take effect at 6:00 a.m. At 6:17 a.m., PJM BA asked Market Participants to submit bids to sell emergency energy in case PJM needed to purchase or import emergency energy, but other actions that PJM took averted the need for the PJM BA to purchase emergency energy. At 6:30 a.m., PJM BA received reports that generators were having to limit their output due to federal government environmental restrictions. PJM petitioned the Department of Energy (DOE), and DOE later granted permission,[169] to lift emissions-related restrictions until noon, Monday December 26.

166 A low ACE event is the Low Balancing Authority ACE Limit (MW), calculated based on the Low Frequency Trigger Limit of approximately 59.95 Hz for the Eastern Interconnection. *See* Figure 49, above, and NERC Reliability Standard BAL-001-2 – Real Power Balancing Control Performance, Attachment 2. RSCompleteSet.pdf (nerc.com).

167 PJM has normally seen performance over the past three years in the 50 – 70 percent response range when calling for synchronized reserves.

168 Reproduced with permission of PJM and copyrighted by PJM.

169 PJM secured the order from the DOE under section 202(c) of the Federal Power Act (16 U.S.C. § 824a(c)). PJM received the DOE order at 5:45 p.m. on December 24 and immediately implemented it.

At 7:15 a.m., PJM BA issued a Voltage Reduction Warning and Reduction of Non-Critical Plant Load, indicating that a voltage reduction[170] may be required during a future critical period. At 7:30 a.m., PJM BA conducted an SOS Transmission conference call on which PJM BA advised TOs to prepare for a Voltage Reduction Action (i.e., order to perform voltage reduction) and to be sure to have their load shed plans in place. By 8:00 a.m., over 24 percent of the PJM generation fleet (approximately 46,000 MW) was experiencing a forced outage, which was higher than the 22 percent forced outage level that PJM experienced during the Polar Vortex in 2014.[171] In total, PJM BA faced approximately 57,000 MW of generator unavailability for the morning peak on December 24 (including planned outages and forced outages that began before the Event). The other load management measures improved system conditions enough over the next few hours that PJM did not need to order voltage reduction or firm load shed on the morning of December 24.[172] At first PJM estimated that its load management efforts reduced load by 7,400 MW, but it later realized that it only received approximately 3,500 MW.[173] Still, PJM was able to restore exports to support its neighbors by 10 a.m. At 10:00 p.m., PJM BA terminated its EEA.

TVA. As shown in Figure 39, above, TVA remained at EEA 3 since the evening of December 23. At 5:51 a.m. on December 24, with its system load still near where it had peaked the evening before, unplanned generation outages still occurring, and its import power curtailed, the TVA BA area again ordered firm load shed of approximately five percent of its peak system load/1,500 MW. At 6:12 a.m., TVA suffered an additional curtailment of import power and ordered an additional five percent firm load shed (10 percent total, estimated by TVA to be a 3,200 MW reduction).[174] TVA later incurred an additional unit trip of nearly 300 MW and was unable to reduce back to five percent of its peak system load until 10:27 a.m. Finally, at 11:30 a.m. TVA BA released its order for the remaining five percent load shed. As system load began to decrease and some generating capacity returned to service, TVA lowered from EEA 3 to EEA 2 at 12:08 p.m., dropping to EEA 1 at 1:07 p.m. and terminating its EEA at 1:45 p.m.

DEC. Already in EEA 1 at the start of December 24, as unplanned generation outages increased and PJM BA curtailed export schedules to DEC, DEC declared EEA 2 at 4:30 a.m., and EEA 3 at 6:10 a.m. By 6:27 a.m., DEC ordered 400 MW of firm load shed, later increasing it to 1,000 MW at 7:10 a.m. Later that morning, as system load dropped and a generation plant returned to service, DEC ordered the restoration of firm load at 10:00 a.m. DEC manually restored the last load shed circuits at 3:45 p.m.

DEP. Experiencing conditions similar to DEC, DEP declared EEA 1 December 24 at 5:37 a.m. DEP escalated to EEA 2 at 6:06 a.m. when its purchased power was curtailed, and to EEA 3 at 6:18 a.m. after an additional generation outage. With system load increasing, DEP ordered 600 MW of firm load shed at 6:25 a.m., but increased it to 800 MW at 7:10 a.m., up to a maximum of 961 MW by 7:56 a.m. By 8:14 a.m. DEP began restoring a portion of its firm load,

170 Based on transmission equipment which exists in certain locations of the BES, electric grid operators can control the transmission equipment to reduce voltage levels to lower the BA system load (while maintaining BES reliability) as an emergency load management measure, in advance of and to reduce the need for firm load shed. *See* PJM Manual 13: Emergency Operations.

171 McGlynn Affidavit, at ¶ 13.

172 At 6:15 p.m. on December 24, PJM ended the Voltage Reduction Warning and Reduction of Non-Critical Plant Load, and the Voltage Reduction Alert at 6:34 p.m.

173 PJM Report at 42 (for December 23 (1,100) and 24 (2,400).

174 In addition to PJM, other BAs neighboring TVA had concerns of meeting their own load/reserve requirements the morning of December 24 based on high electricity demands and unplanned generation outages, derates, and failures to start experienced thus far during Winter Storm Elliott. For example, with the SPP BA experiencing challenges to maintaining adequate operating reserves twice on December 23 during morning and evening peak timeframes, to limit further increase of the export of the SPP BA, the SPP transmission service provider (TSP) reduced their total [power] transfer capability (TTC) of the SPP export interface from December 23, 10:00 p.m., through December 25, 1:00 p.m. SPP BA communicated this action with MISO, TVA and Southern and notified them to contact SPP if they needed assistance and SPP would evaluate its ability to help. These calls were on the morning of the 24th. (*See* SPP Report at 9).

restoring all by 8:43 a.m. DEP improved to EEA 1 at 4:20 p.m.

DESC. With increasing generation outage levels, on December 24, at 4:56 a.m., DESC declared EEA 2 and initiated load management procedures, followed by voltage reductions to reduce system load. By 5:53 a.m., DESC declared EEA 3. At 8:00 a.m., DESC ordered approximately 95 MW firm load shed. DESC was able to purchase 100 MW of import power from Southern, and by 8:09 a.m., restored its firm load. DESC continued to implement load management, customer appeals for conservation, and voltage reduction to lower its system load, and at 7:10 p.m., dropped to EEA 2. DESC remained at this level overnight until 9:00 a.m. on December 25 when it exited its energy emergency.

Santee Cooper. Santee Cooper began experiencing unplanned generation outages related to Winter Storm Elliott during the early morning hours of December 24. At 5:34 a.m., Santee Cooper declared EEA 1, and by 7:18 a.m. was at EEA 3 and ordered 86 MW firm load shed. At 7:33 a.m., Santee Cooper ordered all firm load shed restored.

Southern, NYISO, and ISO-NE. On December 24, due to the unplanned generation outages and increasing loads, Southern BA declared an EEA 1 at 2:00 a.m. The Southern BA requested implementation of voltage reduction programs to help reduce load on its system. Faced with additional unplanned generation outages, at 6:25 a.m., the Southern BA declared an EEA 2 due to declining operating reserves and expected load increase, and requested emergency energy from its neighbors. At 7:00 a.m., Florida Power and Light provided 1,000 MW of emergency energy to the Southern BA Area. As it began to receive emergency energy from Florida Power, the Southern BA was able to provide 100 MW of emergency energy assistance to DESC. By midday, Southern BA load began to decrease, and Southern BA was able to increase this assistance to DESC to 400 MW at 1:00 pm, and by 2:15 p.m., downgraded to an EEA 1. As the need for emergency energy decreased due to improved system conditions in the DESC BA area, Southern BA decreased its emergency energy to 200 MW and finally to 0 MW at 10:00 p.m.

With the winter storm making its way to New York and New England, the governor of New York on Thursday December 22, declared a state of emergency for the entirety of New York, and on the same day, the National Weather Service Buffalo upgraded the winter storm watch to a blizzard warning, and warned of possible blizzard conditions in Buffalo to begin Friday afternoon December 23, and to last approximately 30 hours, with peak wind speeds that could reach approximately 70 mph, with one to three feet of snow.[175] Although there were over 100,000 power outages in the NYISO footprint, as well as tens of thousands of customers without power in the ISO-NE footprint across Maine, Vermont, and New Hampshire, they were mostly due to the winter storm's impact on the electric distribution systems. While there were unplanned BES generation outages in the NYISO footprint during the Event, NYISO did not need to enter into an energy emergency and was able to assist neighboring BAs during the Event, such as PJM, with reserves as described earlier in Section III.

ISO-NE needed to invoke EEA 1 the evening of December 24. ISO-NE incurred over 2,000 MW of unplanned generation outages and derates in its footprint on December 24, and also experienced over 1,000 MW reduction of import power from Hydro Quebec due to the winter storm's impact on Hydro Quebec's system. Those conditions, coupled with high electricity demands, led ISO-NE to declare EEA 1 from 4:30 p.m. to 7:00 p.m., which was then cancelled as conditions improved in its BA.

e. Operating Conditions Improve - Evening of December 24 –December 25

- Core Event Area operating conditions improve
- Energy Emergencies end

175 NEW YORK STATE PREPAREDNESS AND RESPONSE EFFORTS Blizzard of 2022 After-Action Review (August 2023) at 15, https://www.dhses.ny.gov/system/files/documents/2023/08/nys-aar-on-buffalo-blizzard-response.pdf.

As Christmas Eve and Christmas Day unfolded, Event Area electricity demands decreased (as seen on the graph in Figure 39, above). Also, on December 25, extreme cold weather ushered in by Elliott began to subside in some of the BA footprints. Some generating units also returned to service and increased BA reserve levels. However, also as shown in the Figure 39 timeline, above, multiple BAs were experiencing Energy Emergencies which extended into midday, December 25, although none needed to shed firm load on Christmas Day:

- DEC BA, returned to EEA 1, December 24, at 4:00 p.m., EEA 1 cancelled on December 25, at 11:00 a.m.
- DEP BA, EEA 1 cancelled on December 25, at 9:00 a.m.
- DESC BA, cancelled EEA 2 on December 25, at 9:00 am.
- Santee Cooper BA, EEA 2 until December 25, 5:04 a.m., EEA 1 cancelled December 25, at 9:00 a.m.
- Southern BA, EEA 1 cancelled December 25, 12:00 noon.
- PJM BA, EEA 1 cancelled December 24, at 10:00 p.m.

4. NATURAL GAS PIPELINE OPERATORS' REAL-TIME ACTIONS

a. Pipeline Operator Actions Due to Natural Gas Supply Shortfalls and Equipment/Facility Outages

1. Gas Pipeline Scheduling

The natural gas scheduling system is based on the Gas Day which is standard nationwide, beginning at 9:00 a.m. CCT[176] and ending at 9:00 a.m. CCT the following day. All nominations for transportation service are for a daily quantity to be transported over that 24-hour period. The rate at which a shipper may use its contracted quantity, also known as a flow rate, on a given pipeline is determined by the individual pipeline's tariff and the flexibility of that pipeline to permit non-ratable flows (that is, delivery in a single hour of more than 1/24 of the daily nominated quantity). Except for special services, pipeline services are generally based on the assumption of uniform hourly flows over the Gas Day.

At a designated time each day, a shipper "nominates" a quantity of natural gas that it wishes to have transported by the pipeline under a transportation contract between receipt and delivery locations on the pipeline. The nomination goes through a confirmation and scheduling process to ensure that the nomination matches the amount of gas that the pipeline will receive from or deliver to the designated locations, and that there is enough available capacity for the nomination to flow. Before a pipeline schedules a shipper's nominated quantity of natural gas for transportation, the pipeline confirms the shipper's nomination with upstream and downstream parties to make sure the shipper has contracted for sufficient gas with an upstream supplier to fulfill its nomination, and to ensure the downstream entity, such as an LDC, has sufficient capacity to accept the gas. If demand for service along a specific path exceeds the pipeline's capacity (i.e., if a pipeline has capacity constraint), priority rules are used to schedule higher priority nominations while lower priority nominations are reduced or rejected. After all gas has been scheduled, nominations are confirmed back to the shippers and the pipeline is obligated to deliver the confirmed nominated quantity of gas.

2. Gas Pipeline Operations Under Normal Conditions

Natural gas pipelines (and LDCs) have operations centers or control rooms that are staffed 24 hours a day, every day of the year. Pipeline personnel known as controllers monitor the pipeline systems for, among other things, operational status, natural gas flow rates, and readings of the natural gas pressure within the pipeline and temperatures. Controllers are the first to notice and respond to abnormalities such as pressure changes or compressor failures and notify and to communicate with field personnel who respond to these conditions.

Each pipeline must maintain a minimum pressure for gas to flow and must stay below the maximum allowable

176 Central Clock Time, which is Central Standard Time except during Daylight Savings Time, when it is one hour in advance of Central Standard Time.

operating pressure at which it can safely operate (MAOP). Like electric grid operators, pipeline operators use Supervisory Control and Data Acquisition (SCADA);[177] pipelines use it primarily to monitor the flow of gas on the system.

Line pack is the volume of gas maintained or held within a pipeline system. The more gas that is "packed" into the pipeline, the higher the pressure. System operators continually manage the amount of gas in their pipelines to ensure that customer demands can be met while staying within safe and reliable pressure ranges, which vary from pipeline to pipeline. Pipelines rely on line pack to match the time-varying demands of their customers (shippers) and the supply of natural gas that generally is injected into the pipeline at a consistent rate through the day (production gas). Under normal operating conditions, line pack on a pipeline goes through a 24-hour cycle. During the morning peak, when some shippers, such as electric generating units, withdraw gas at a non-ratable flow rate, the line pack decreases. Later in the day, when shippers either pause or decrease the rate of gas withdrawal, pipelines pack the lines to replenish the gas taken off the system. As long as a customer's gas usage does not threaten the pipeline system's integrity, pipeline operators may provide customers with the flexibility of non-ratable flows or deviation from their scheduled quantity. Additionally, pipelines generally offer balancing services and bill their shippers monthly to allow for daily fluctuations. This allows shippers up to 30 days to balance the amount of gas that shippers delivered into the pipeline with the quantity of gas that was taken off the pipeline. Lastly, during normal operating conditions, if the pipeline is not constrained and is able to meet all of its firm contractual nominations, any excess capacity can be used for interruptible transportation service.

Ahead of weather events or at other times that stress the system, a pipeline system operator will store gas in its transmission system during the hours of low demand (packing) leading up to the event, and then use that gas during the hours of high demand, reducing the amount of gas in the system (drafting). During periods of high demand, natural gas supplies flowing ratably[178] into a pipeline over the 24-hour gas-day period may not be sufficient to satisfy the increased demand from shippers in the same overlapping period leading to the draft condition. A draft condition occurs when supply is less than demand. This may occur on an hourly or daily basis. A draft condition leads to lower line pressure and/or reduced line pack, to which operators respond with a variety of approaches, such as reduced system tolerances and the use of natural gas imbalance management techniques designed to maintain system integrity and provide reliable service to all shippers.

During constraint periods, a pipeline may more strictly enforce ratable flows and reduce system imbalances by requiring shippers to match their supply of gas delivered into the pipeline with the amount taken out. If a shipper's supply of natural gas into the pipeline is less than its nominated amount, a pipeline may reduce the shipper's confirmed nomination to match the amount of natural gas actually delivered into the pipeline system.[179] Pipelines may also use the types of notices described below in the sidebar on pipeline communications to keep the system balanced and within operating pressure range.[180] By using notices to reduce the amount of gas customers may take off the pipeline or the rate at which the gas is being taken off, pipelines can keep pressure up. During the Event, one pipeline restored its line pack by reversing flow in a segment of its system, but not all pipelines have that ability. Pipelines may also reduce or curtail certain

177 A Supervisory Control and Data Acquisition (SCADA) system operates via coded signals sent over communication channels to remote stations to monitor and provide control of remote equipment.

178 Meaning at a constant rate; receipt operators flow on a steady-rate basis as mentioned above. Steady-state flow refers to the condition where the fluid properties at a point in the system do not change over time.

179 Changes in gas deliveries do not occur instantly. Operational Balancing Agreements (OBA) contractually specify how gas imbalances between flows and scheduled amounts are to be managed. Interstate pipelines are obligated by FERC regulations to have OBAs at interconnects with other interstate pipelines and with intrastate pipelines. These agreements enable counterparties to make operational changes and revise nominations.

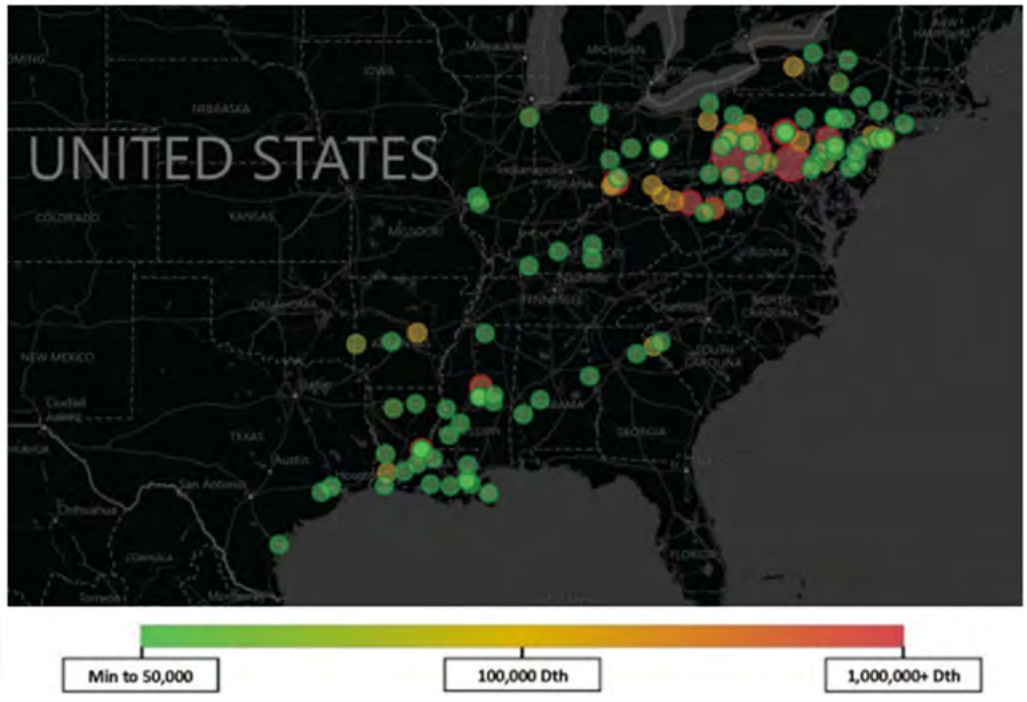
180 *See* sidebar on pipeline communications at 76, below.

transportation services based on their priority level (e.g., interruptible transportation) if their capacity cannot meet all of the demand.

Pipelines can turn some facilities on and off, whether by remote operation via SCADA or manually using field personnel, to alleviate pressure concerns that could affect the reliability of their system. However, this option is rarely exercised. In 2011, New Mexico Gas Company curtailed pipelines to several rural communities when it received reports of no gas or low gas pressure in the Albuquerque area, indicating that its system was near collapse.[181] These curtailments allowed pressure to recover in the remainder of its system. The option to turn off facilities feeding shippers at designated delivery points that are supplying less gas than they are withdrawing is rarely, if ever, exercised. If enough customers take more gas than they are entitled to, this can negatively affect pipeline pressures for customers located farther down the pipeline.

Interstate pipelines use storage to support system operations (e.g., to provide system balancing or support no-notice transportation services), to provide contract storage services, or a combination of both. Interstate pipeline companies, intrastate pipeline companies, LDCs and independent storage service providers may own and operate underground or above-ground storage facilities. However, the owners/operators of storage are not necessarily the owners of the natural gas held in storage.

Figure 50: Magnitude of Supply Shortages by Receipt Point Locations for Gas Days December 20-26, 2022



Most of the working gas held in storage belongs to shippers, LDCs, or end users who own the gas. Some interstate pipelines reserve varying amounts (from three percent to 22 percent) of their natural gas storage capacity to support their system operations. During extreme cold weather events withdrawals from customers with rights to storage such as LDCs (for natural gas-fired home heating, among other uses) increases. In Winter Storm Uri, the South Central Region (including Texas) saw record storage withdrawals of 156 Bcf for the week ending February 19,

181 2011 Report at 127-130.

2021, which were instrumental in preventing more adverse outcomes on both the natural gas infrastructure system and the grid.

Each of these tools is important in maintaining the reliability of the pipeline system, allowing operators to ensure the proper amount of gas flows through the system. Force majeure can be issued when emergency conditions, such as freezing of equipment, threaten operations. OFOs are important because they notify shippers to stay within their nominated and confirmed quantities of gas or risk penalties.

3. Gas Pipeline Real-Time Operations During Winter Storm Elliott

Once Winter Storm Elliott struck, many pipelines began to experience decreased natural gas supply at numerous receipt points, which are the points where pipelines receive gas into their system. Figure 50, shows the magnitude of supply shortages during the relevant period by receipt point locations. Ten out of the 15 surveyed pipelines reported supply loss or underperformance, defined as the actual physical receipts being less than the shipper's confirmed nomination. The magnitude of supply loss is represented on Figure 50 by the green to red color gradient, with red indicating a higher volume of supply loss. Figure 50 clearly shows significant supply reductions at receipt points located in the Marcellus and Utica Shale formations. Pipelines also indicated that although they can track the volume of supply underperforming at receipt points on their respective systems, they were not always privy to the upstream issues causing the supply loss.

Pipeline Communications

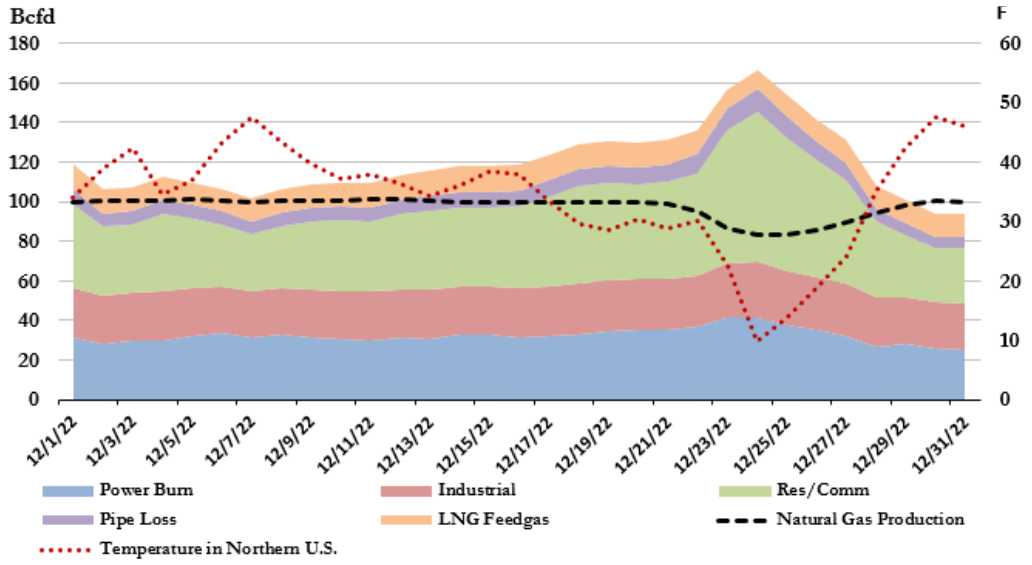
Interstate pipelines issue a variety of communications and directives to shippers and, pursuant to FERC regulations (18 CFR §284.12 (2022)), post critical notices to describe strained operating conditions, to issue operational flow orders and, when applicable, to make force majeure announcements. Most intrastate pipelines provide similar information and instructions to shippers, either by posting or direct communications.

Critical notices describe situations when the integrity of the pipeline system is threatened. A critical notice will specify the reasons for and conditions making issuance necessary, and also state any actions required of shippers. Operational integrity may be determined by use of criteria such as the weather forecast for the market area and field area; system conditions consisting of line pack, overall projected pressures at monitored locations, and storage field conditions; facility status (defined as horsepower utilization) and availability; and projected throughput versus availability, for capacity and supply.

Operational flow orders (OFO) are used to control operating conditions that threaten the integrity of a pipeline system. (Individual pipeline companies may have other names for operational flow orders such as alert days, performance cut notices or an emergency strained operating condition). OFOs request that shippers balance their supply with their usage on a daily basis within a specified tolerance band. An OFO can be system-wide or apply to selected points. Failure by a shipper to comply with an OFO may lead to penalties. Pipelines may also limit services such as parking and lending of natural gas, no-notice (the provision of natural gas service without prior notice to the pipeline), interruptible storage and excess storage withdrawals and injections.

Force majeure, if authorized by the pipeline's tariff, is a declaration of the suspension of obligations because of unplanned or unanticipated events or circumstances not within the control of the party claiming suspension, and which the party could not have avoided through the exercise of reasonable diligence.

Figure 51: Natural Gas Supply and Demand, December 1 – 31, 2022[182]



Starting the morning of December 23, pipeline operators were faced with increasing demand for natural gas after seeing supply shortfalls throughout the night of December 23 (see supply and demand pattern in Figure 51, above). Supply shortfalls peaked on December 24 at 7.1 Bcf. The mismatch between supply and demand challenged pipeline operators' ability to provide consistent, dependable natural gas operations needed by generating units. Line pack was one strategy pipelines used to handle these hourly fluctuations in supply and demand, partially to assist generators' operations.

Figure 52 below, shows that the ongoing imbalance between the gas entering and leaving the pipeline systems caused the interstate pipelines' line pack to continuously drop throughout December 24. Pipelines actively monitored their line pack and pressures and responded promptly; issuing underperformance notices to shippers to inform them that they were not supplying all of the gas they were obligated to supply. To meet confirmed nominations of customers, pipelines used line pack and/or gas from storage to try to cover shortfalls as much as possible. These efforts were successful at the onset of the storm, allowing pipelines to deliver confirmed nominations of gas to meet customers' demand. However, as the storm progressed, supply shortfalls continued and customers' demand increased to a level where some customers began taking more gas than what they supplied and/or confirmed through nominations, which contributed to low pipeline pressures. On December 24, due to the mismatch of shippers' receipt and delivery volume, multiple shippers' confirmed nominations were reduced to match their supply of gas into the pipeline.

Figures 53 and 54, below, show the notices issued by the pipelines in advance of the Event on December 20 as well as during the Event from December 21 to 26. Force majeure and OFO issuances peaked on December 23, while critical notices peaked on December 24. One pipeline had compressor station outages that led to three force majeure issuances, affecting 93 firm shippers; another issued five force majeures from December 23 to 25 due to freezing-related compressor station outages, affecting 63 firm shippers.

182 Source: S&P Global Commodity Insights, ©2023 by S&P Global Inc.

Figure 52: Average of Normalized Line Pack Pressures For the 15 Interstate Pipelines Surveyed, December 20 – 26, 2022

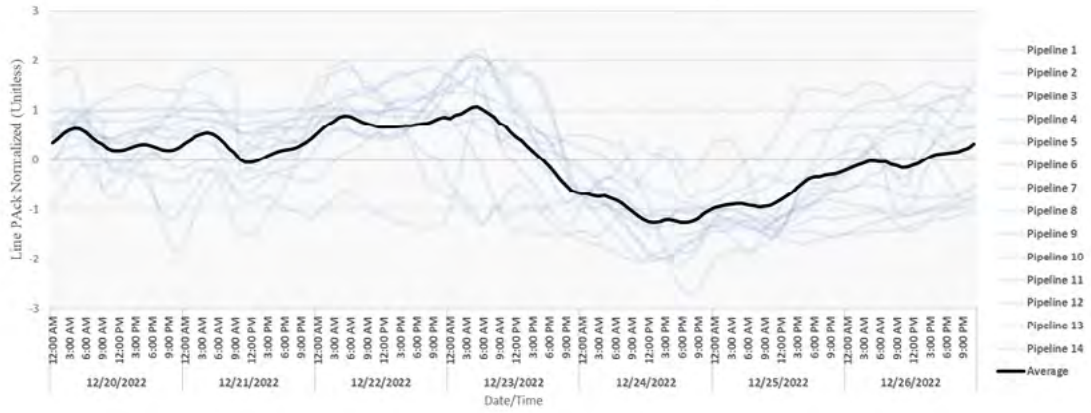


Figure 53: Interstate Natural Gas Pipeline Notices Issued, December 20 – 26, 2022

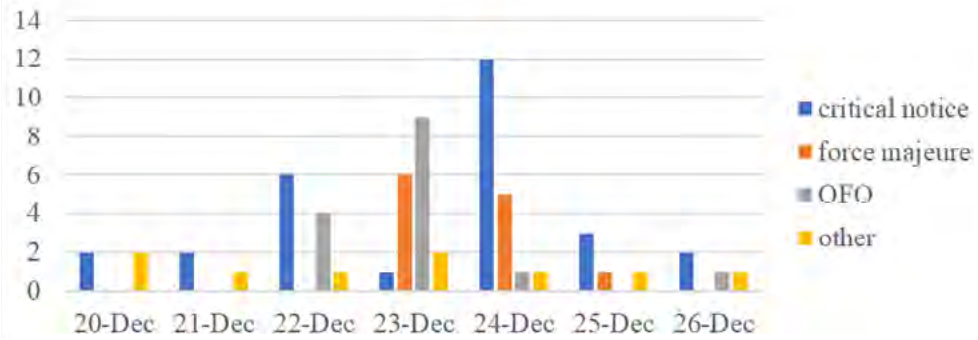
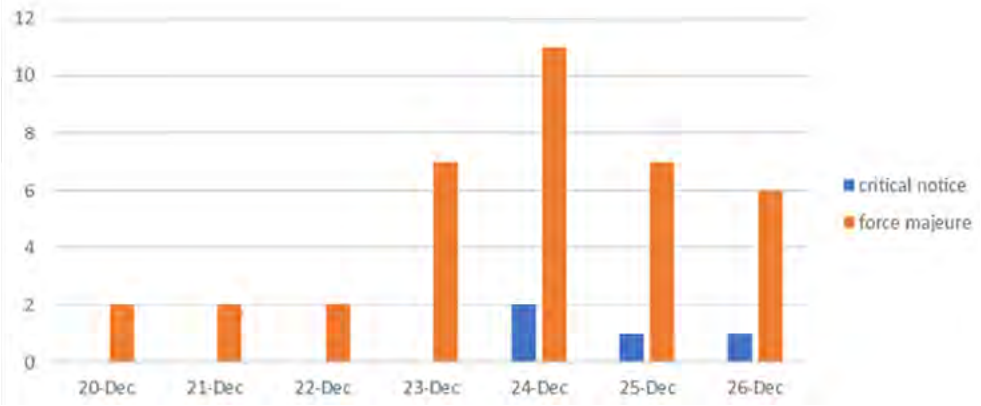


Figure 54: Ongoing Notices with Associated Flow Reductions, December 20 – 26, 2022



Low pipeline pressures caused by reduced gas supply entering pipelines combined with increased demand also resulted in issues at interstate pipeline interconnections with other pipelines, where shippers' gas supply quantities were inconsistent with shippers' confirmed nominations on the receiving pipeline; resulting in confirmed nominations that failed to align with the quantity of gas flowing. These issues caused imbalances

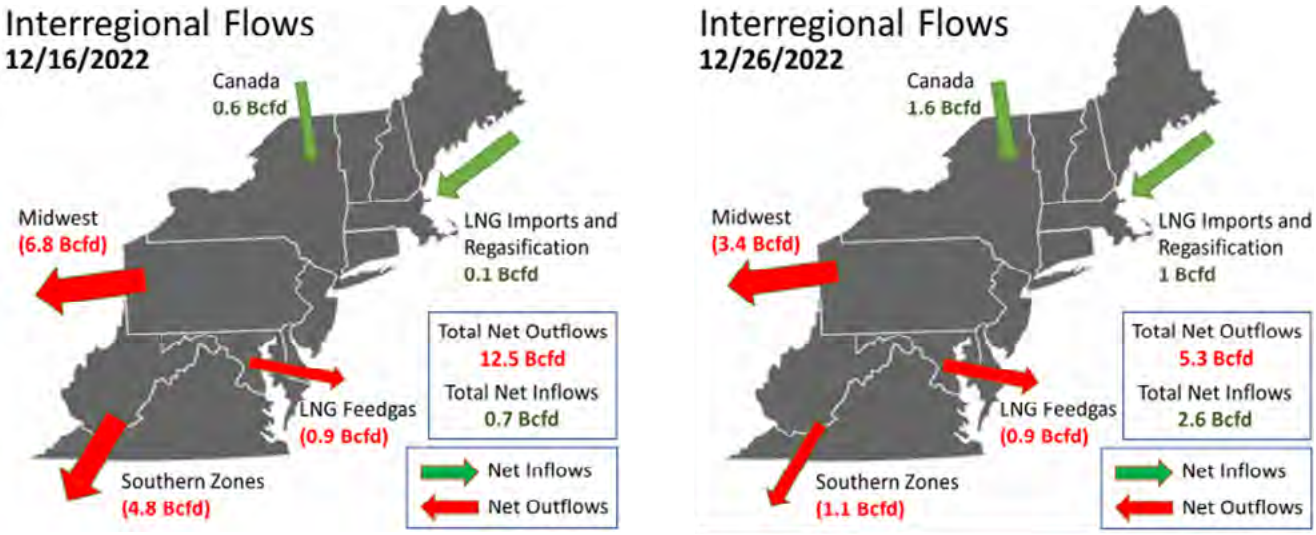
between supply and demand at pipeline interconnection points, requiring some pipelines to implement scheduling restrictions and forcibly reduce previously confirmed nominations. The scheduling restrictions and forcible reduction of confirmed nominations may not have been necessary if non-performing shippers had acted to address their lack of performance. The pipelines had to contact those shippers repeatedly to find out how they planned to balance their gas flows and in some instances were unable to do so before it became necessary to implement scheduling restrictions and reduce nominations.

Several of the pipelines communicated with PJM or NYISO during the Event. These discussions allowed the pipelines to obtain useful information, for example, about PJM's load forecast or burn profiles for gas generators, and to share the performance of their systems and available capacity with the BAs. One pipeline provided PJM with a list of receipt points that were underperforming according to their nominated levels.[183]

2. INTERREGIONAL NATURAL GAS FLOW PATTERN CHANGES

As weather affected natural gas supply, demand, and pipeline operations, the movement of natural gas between regions in the eastern half of the United States changed. The Northeast region reduced outflows to neighboring regions and increased imports from Canada, while the Southeast region simultaneously increased outflows to the Midwest, decreased outflows through LNG exports, and had less access to Northeast supply.

Figure 55: Natural gas flows into and out of the U.S. Northeast region[184]



Since the dramatic growth of shale natural gas production in the Northeast began over a decade ago, the region has produced substantially more natural gas than it consumed, allowing for net outflows of

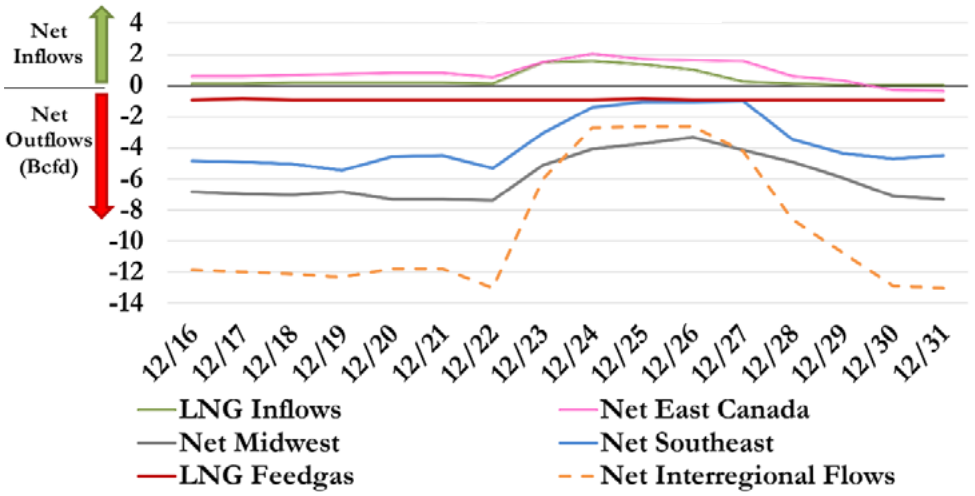
183 Winter Storm Elliott hit on a holiday weekend. This created pressure on pipelines' communications teams because of an increase in shipper inquiries due to the large volume of confirming party reductions they issued. This required some of the pipelines to call in vacationing staff.

184 Flow size arrows are approximate. Region borders are generalized and may not reflect modeled pipeline zones. Source: S&P Global Commodity Insights, ©2023 by S&P Global Inc.

natural gas to the south and west most of the time.[185] As seen in Figure 55 above, however, by the end of the Event, net scheduled outflows declined to just 5.3 Bcfd, compared to typical outflows of about 12.5 Bcfd (as measured a week earlier). The Northeast also typically sees substantial imports from Canada over the winter, and during the Event the Northeast increased its imports from Canada, with most of the LNG imports received coming from the Saint John LNG facility in New Brunswick, Canada. Net flows toward the southeast fell 4.8 Bcfd on December 16 to just over 1 Bcfd on December 26, which was the biggest portion of the reduction in total net outflows from the Northeast.

The change in flow patterns was not enough to change the Northeast into a net importer of natural gas, but, as seen in Figure 56 below, overall net outflows from the region reached a low of just under three Bcfd over the Christmas weekend. Flows did not return to their pre-storm levels of about 12 Bcfd, until December 30, 2022. Net outflows from the Northeast to the Midwest reduced by half during the Event as shippers in the Northeast kept more gas in-region and drops in production meant less gas was available after meeting Northeast regional demand. Cove Point LNG in Maryland consistently received flows for export throughout the Event, but also appears to have delivered significant volumes of natural gas back onto the pipeline system from its on-site storage at the same time.

Figure 56: Net Interregional Flows From the Northeast Over the Second Half of December 2023[186]



For the last decade, the Southeast region typically has received substantial net inflows, reversing the historic northwards flow direction on many of the major interstate pipelines. The Midwest market has in the recent past been supported by Northeast outflows, but during the Event Northeast outflows to the Midwest declined, creating room for flows from the Southeast. As a result, flows from the Northeast declined substantially while the Southeast increased net outflows to the Midwest. LNG feed gas demand declined, possibly due to higher supply costs for exporters that rely on spot purchases or difficulty in obtaining transportation capacity for exporters that use interruptible transmission. As seen in Figures 57 and 58 below, some

185 The data presented in this section is based on scheduled Intraday Cycle 3 nominations, which may not reflect actual pipeline flows due to irregular receipts by shippers.

186 Source: S&P Global Commodity Insights, ©2023 by S&P Global Inc.

amount of LNG regasification occurred in the Southeast during the Event, likely at LDC storage facilities and possibly at some LNG export facilities.

Figure 57: Natural Gas Flows Into and Out of the U.S. Southeast Region[187]

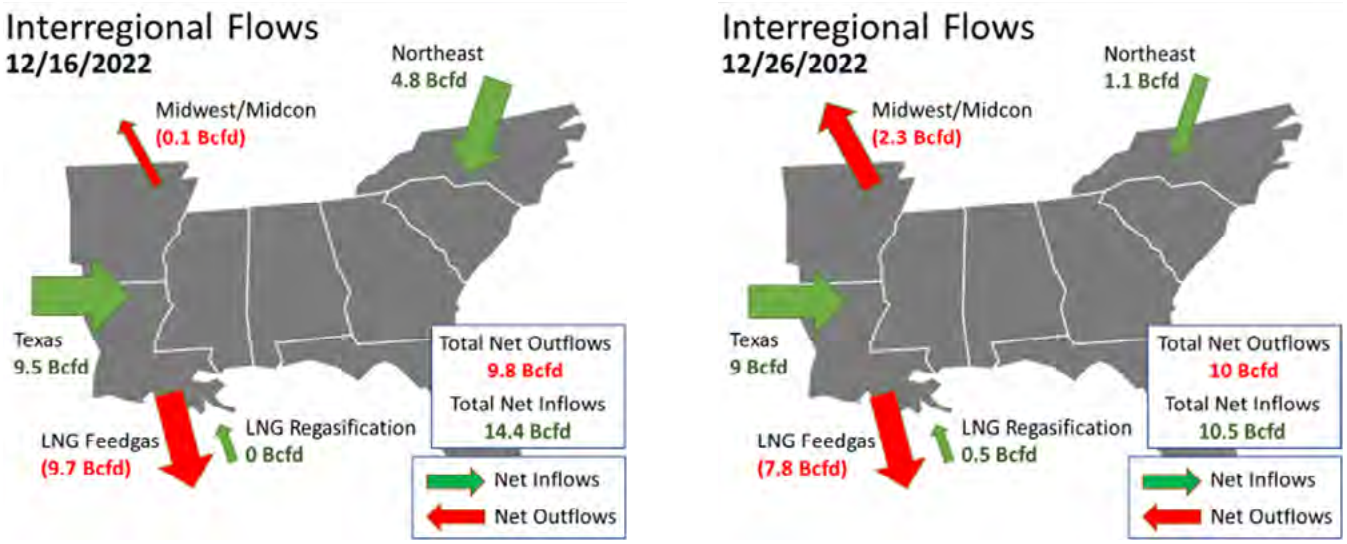
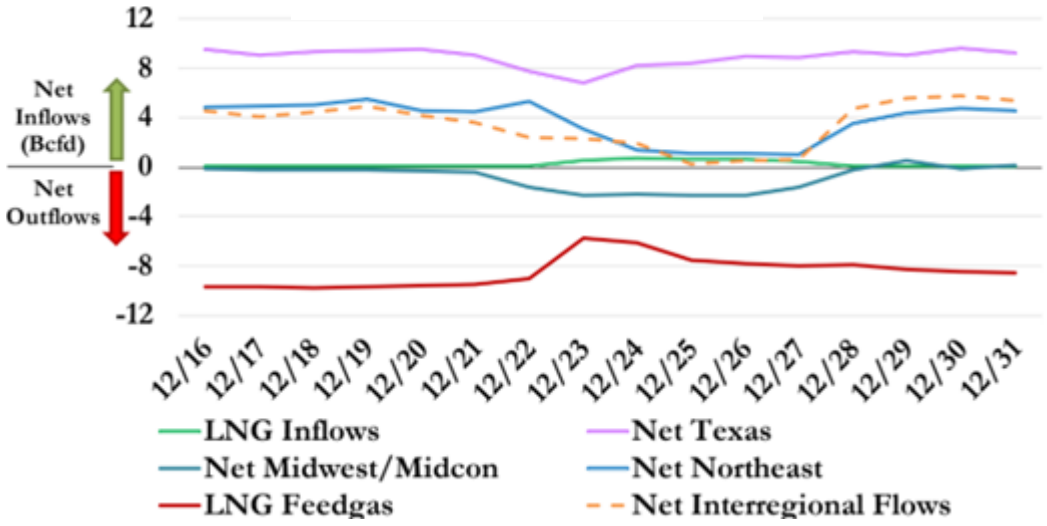


Figure 58: Interregional Flows from the Southeast over the second half of December 2023[188]



a. Storage Operations

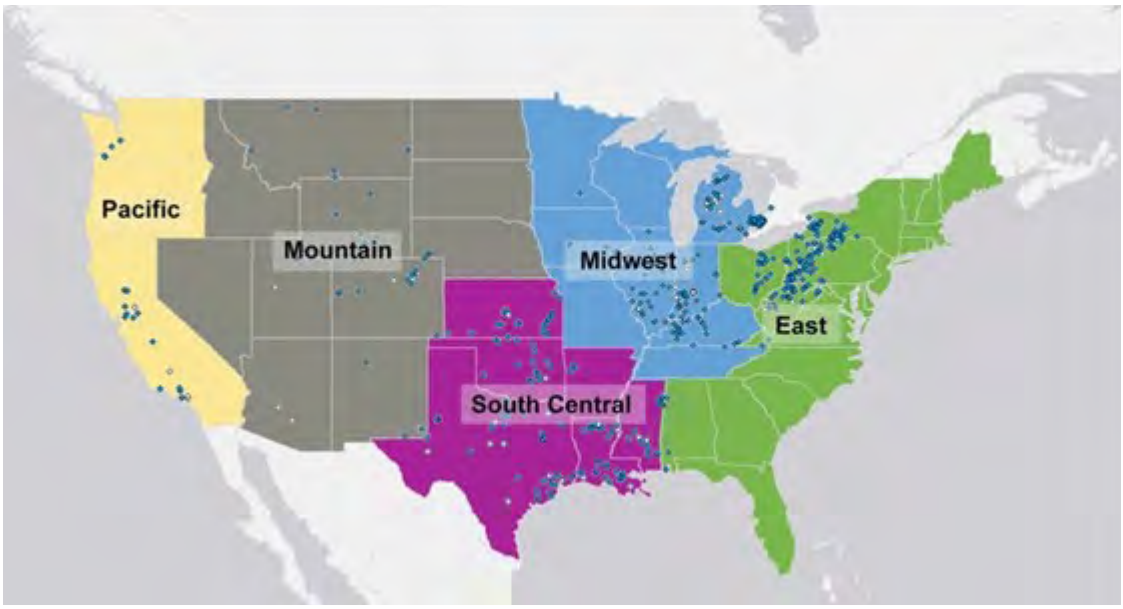
The U.S. Energy Information Administration (EIA) collects and provides weekly estimates of working gas volumes held in underground storage facilities in the lower 48 states and at five regional levels. EIA breaks down regions

187 Flow size arrows are approximate. Region borders are generalized and may not reflect modeled pipeline zones. Source: S&P Global Commodity Insights, ©2023 by S&P Global Inc.

188 Source: S&P Global Commodity Insights, ©2023 by S&P Global Inc.

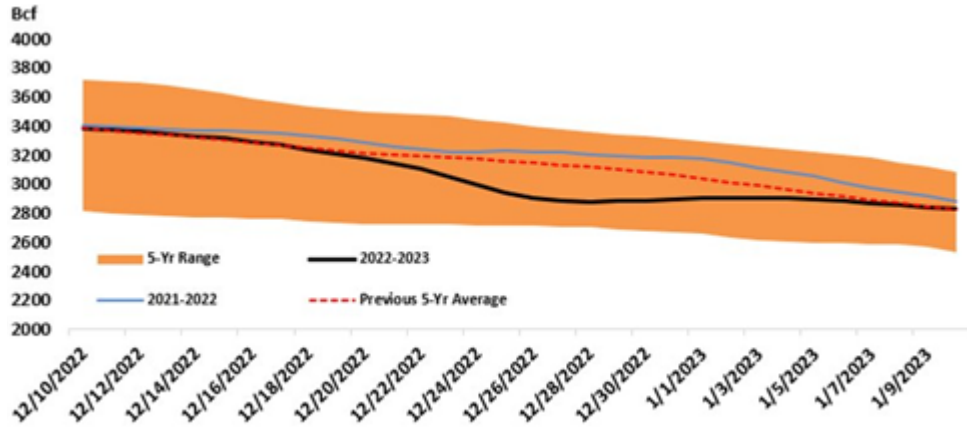
for natural gas storage into the Pacific, Mountain, Midwest, South Central, and East. These are geographically-defined regions and the storage fields are concentrated in the South Central, East, and Midwest regions (see Figure 59, below). Changes in these gas inventories on a weekly basis primarily reflect net withdrawals or injections.

Figure 59: Natural Gas Storage Field Regions of the U.S.



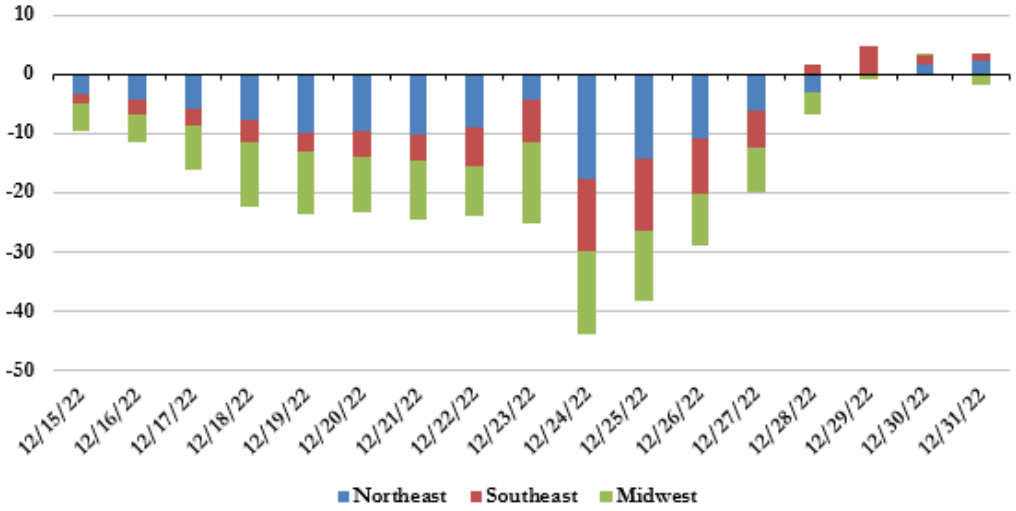
According to S&P Global Insights data there was a notable decline in inventory of stored natural gas during the Event, which reflected reliance on stored natural gas as natural gas production fell and demand increased. Although the natural gas storage levels did not dip below the lowest level reflected in the five-year range, they did dip below both the five-year average and levels seen the year before (see Figure 60, below). S&P uses different regions from EIA, which vary slightly in the Event Area (e.g., Ohio and Kentucky are in the Northeast, not the East, and there is no South Central, only Southeast, Texas and Midcon Producing (Oklahoma, Arkansas, and Kansas).

Figure 60: Natural Gas Storage Levels: November 18, 2022 – February 3, 2023, and Five-Year Average for Same Period[189]



The majority of withdrawals during the Event were in the South Central, Midwest, and East Regions (see Figures 61 and 62, below). Once the storm passed and temperatures rose, gas returned to storage and the South Central region experienced net positive injections. During the Event, 235 Bcf of natural gas was withdrawn from storage nationwide to meet the heightened natural gas demand, a 55.5 percent increase in withdrawals from storage as compared to the five days prior (December 16-21). Regionally, the three most affected regions of the Northeast, Southeast, and Midwest withdrew 160.0 Bcf of natural gas from storage, nearly 70 percent of all withdrawals from storage in the U.S.

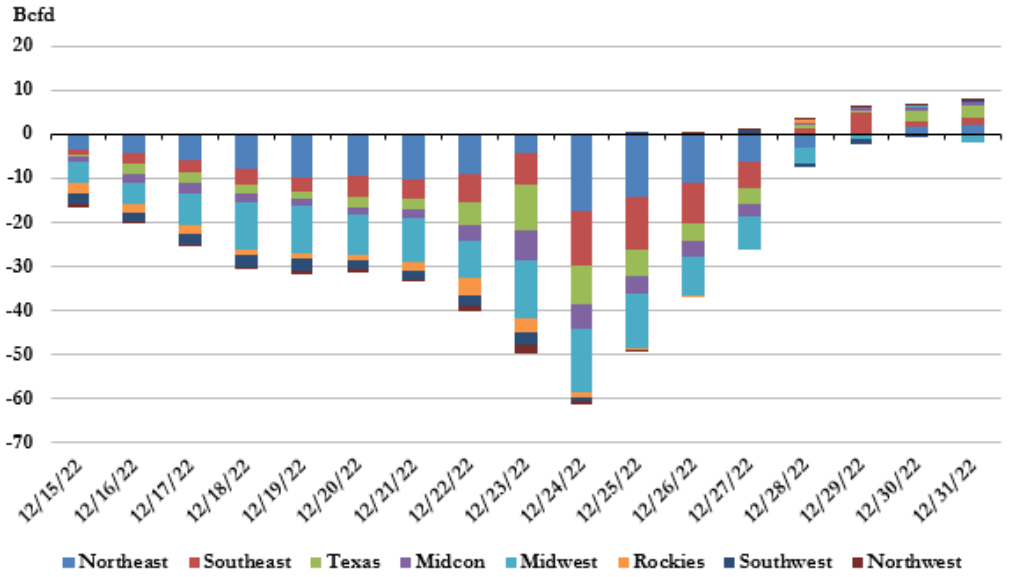
Figure 61: Natural Gas Storage Net Withdrawals From the Relevant Regions: December 15 – December 31, 2022[190]



189 Source: S&P Global Commodity Insights, ©2023 by S&P Global Inc.

190 Figures 61 and 62: source: S&P Global Commodity Insights, ©2023 by S&P Global Inc.

Figure 62: Natural Gas Storage Net Withdrawals in the U.S.: December 15 – December 31, 2022



c. Natural Gas-Fired Generating Units Faced with Loss of Interruptible Transportation, Inability to Find Sufficient Supply, and Force Majeure Cutoffs of Firm Transportation

The mismatch between the availability of gas and the demand from natural gas-fired generating units on December 23 and 24 had an immediate and substantial impact on generation. Natural gas-fired generating units that responded to inquiry data requests relayed their experiences in this period:

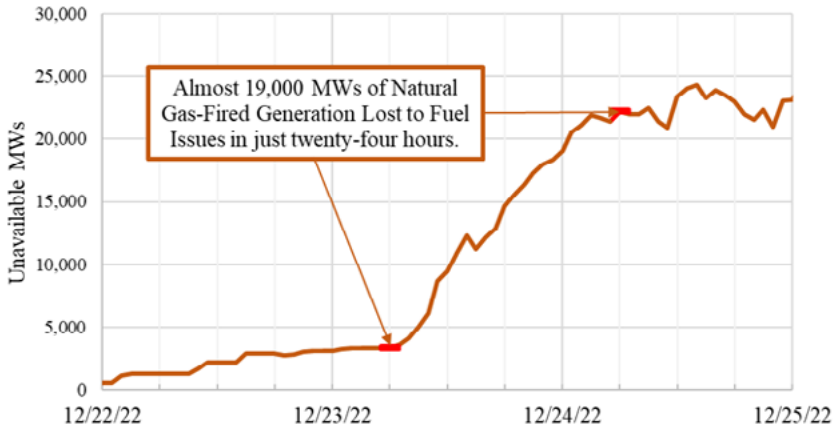
- A 300 MW+ fossil steam unit in SPP cut its generation in half early on December 23 because the gas supplier under its interruptible pipeline delivery arrangement was experiencing a supply limitation.
- An 800 MW+ combined cycle unit in PJM with a firm supply contract reported, on the morning of December 23, that it was forced to cease generating entirely because "gas fuel [was] unavailable."
- Four affiliated gas turbines in PJM, whose collective capacity was in excess of 800 MW, reported on December 23 that fuel unavailability due to market conditions had caused them to stop generating.
- Six centrally-located affiliated gas turbine units owned by a vertically-integrated utility, each with a capacity of nearly 200 MW, reduced their generation by more than 50 percent on the afternoon of December 23 because their pipeline was unable to provide the minimum delivery pressure to the units.
- In the late afternoon of December 23, a gas turbine located in PJM with nearly 200 MW capacity ceased generation because its gas supplier was unable to meet its needs under its firm pipeline delivery arrangement.

These individual narratives—just a handful of examples from many—illustrate the larger collective experience of natural gas-fired generating units during this critical period. On December 23 and 24, more than 41,700 MW of natural gas-fired generation reported outages, derates, or failures to start due to Fuel Issues. Figure 63, below lists the major sub-causes of Fuel Issues experienced by natural gas-fired generating units.

Figure 63: Gross Unavailable MW, Natural Gas Units Experiencing Fuel Issues, Top Sub-Causes, December 23-24, 2022

Fuel Issue - Sub-Cause[191]	December 23	December 24
Interruptible Pipeline Delivery Interruption	6,268	5,485
Market Issues	5,173	9,913
Firm Pipeline Delivery Curtailment	4,533	700
Gas Delivery Pressure Issues	1,532	2,557
Market Price Restriction	1,040	0
Failure to Fulfill Firm Supply Obligations	972	2,852
Transportation Scheduling Constraints	716	0
TOTAL	**20,234**	**21,507**

Figure 64: Incremental Unplanned Unavailable Generation in the Event Area, Natural Gas Units, Fuel Issues, December 22 - 25, 2022



There is a clear relationship between these outages and the system-wide struggle to obtain gas and maintain pressures described above. As illustrated in the below chart, there is a sharp upwards trend in net incremental natural gas-fired generation lost to Fuel Issues beginning the morning of December 23, just as pipelines began to experience supply shortfalls. As illustrated in Figure 64 above, starting that morning, and over the next 24 hours, nearly 19,000 MW of net incremental generation from natural gas-fired generating units were lost due to Fuel Issues.

d. Reliability-Threatening Delivery Pressure Decreases at Major Natural Gas LDC Citygate

Winter Storm Elliott greatly impacted the operations of Consolidated Edison Company of New York, Inc. (Con

191 The following are descriptions of above sub-causes: Interruptible Pipeline delivery Interruption - Interruptible pipeline transportation unavailable due to contractual or tariff provision; Market Issues - Market issues other than high market prices, such as unable to purchase gas in short-term market (could not find a gas supplier in the market); Firm Pipeline Delivery Curtailment - Firm pipeline gas transportation curtailed (reduction of gas deliveries; Force majeure, Pipeline enforces ratable takes provision to tariff levels); Gas Delivery Pressure Issues - Delivered gas pressure below Generator's minimum operating pressure (e.g., pressure too low for generator to operate); Market Price Restriction - High market prices (chose not to purchase gas due to high market prices); Failure to Fulfill of Contractual Obligations - Failure of fuel supplier to fulfill firm contractual obligations (Selling counterparty fails to deliver firm gas to primary pipeline receipt point, force majeure on the supply); Transportation Scheduling Constraints - Transportation scheduling constraints due to Holiday schedule (less gas scheduled than needed).

Edison),[192] the natural gas LDC for Manhattan, The Bronx, and portions of Queens and Westchester County, NY. On Christmas Eve morning, the five interstate natural gas pipelines serving Con Edison began experiencing drops in pressure at Con Edison's citygate due to production losses and operational issues. The pressures declined precipitously and at noon, the pipelines informed Con Edison that they had exhausted their line pack and storage withdrawals, and pressures would not improve until demand decreased. Con Edison managed to supply its customers with gas and maintain necessary pressure, by declaring an internal Gas System Emergency and implementing its specification for "Limiting Gas Use and Load Shedding During a Supply Curtailment or Emergency." As part of the Gas System Emergency, Con Edison activated its LNG regasification plant.

Had Con Edison's citygate pressures not recovered, it was in danger of losing pressure on, or needing to cut service to, all or large portions of its system. Even losing service to 130,000 customers would be considered a major outage and could have taken five to seven weeks to restore, depending on the availability of mutual aid. Had it lost the majority of its system, over a million customers in New York City and nearby areas would have been unable to heat their apartments and houses while the outside temperature was in the single digits, for months. Moreover, a system-wide outage would likely have caused extensive property damage due to damaged water pipes within homes and buildings. Critically, these dire circumstances occurred despite Winter Storm Elliott not qualifying as a "design day" event. LDCs designate certain parameters for "design day" events to plan gas capacity requirements, and a "design day" reflects the highest gas demand that the LDCs expect to be obligated to serve on an extremely cold winter day. The actual average temperatures on December 23 and 24 in the Con Edison service territory were 17 and 15 degrees, respectively. By contrast, Con Edison's design day is based on a zero-degree temperature variable.[193]

On December 16, Con Edison began to prepare for Winter Storm Elliott, including communicating with relevant stakeholders to coordinate in preparation for the storm. In addition to standard daily communications, weather event coordination efforts began on December 19 between Con Edison, National Grid, and Pipeline Control from Enbridge, Inc. (Texas Eastern Transmission, LP ("Texas Eastern") and Algonquin Gas Transmission, LLC ("Algonquin")) (collectively, "Enbridge"), Williams Companies Inc. (Transcontinental Gas Pipe Line Company, LLC) ("Williams"), and Iroquois Gas Transmission System, L.P. ("Iroquois") to discuss upcoming weather patterns and event preparation plans specific to the New York City market area.

On December 21, Con Edison notified its interruptible customers that they were being curtailed and issued OFOs. Additionally, due to colder trending forecasts and overlapping restrictions with Kinder Morgan Inc. (Tennessee Gas Pipeline Company, LLC), Con Edison activated its compressed natural gas (CNG) station and scheduled it to capacity. As the storm worsened, Con Edison issued additional curtailment notices to customers with dual-fuel interruptible and off-peak firm sales and transportation covering December 23 through 27. Also on December 23, Con Edison placed its liquid natural gas facility on stand-by. On December 24 Con Edison

192 Con Edison and its affiliated companies maintain a portfolio of contracts with varying lengths of expiration and flexibility. The companies have entered into supply agreements that are designed to provide reliable service to firm natural gas customers under design day winter conditions in the service areas. These contracts include firm gas supply (100 percent domestic or LNG), firm pipeline transportation, production area and market area storage, firm peaking services, LNG, and citygate baseload supplies. Con Edison had contracted for more interstate pipeline capacity and natural gas commodity than required to meet customer demand on December 24.

193 Con Edison uses a weather concept called "Temperature Variable" (TV) as a reference point in the weather adjustment process. The TV is used in calculating and forecasting future system peak demands, considering extreme winter weather conditions (sustained low temperatures over two Gas-Day periods). The gas day average (GDA) temperature is a 24-hour arithmetic average starting at 10 a.m. using the Central Park National Weather Station dry bulb temperature. The formula for calculating the system TV on a daily basis incorporates two days' worth of GDA's. The current day's GDA is weighted at 70 percent and the previous day's GDA at 30 percent.)

issued OFOs that restricted short positions to two percent of gas scheduled through the Event and began hourly transportation restrictions to 1/24th of schedule. At this time, all of Con Edison's upstream interstate pipelines had imbalance OFOs in place restricting the availability of unscheduled gas. Con Edison's upstream pipelines also began reporting various issues including operating constraints, receipt points underperforming, upstream low pressures, compressor station issues, force majeure, and maxed out line pack.

The Con Edison system performance continued to be within expected operating ranges through December 23. Despite interstate pipeline pressures beginning to fall at Con Edison's metering and regulating stations (which measure and control the pressure of gas and interconnect with interstate pipelines), the impacts on supply to Con Edison were within normal expectations through the morning of December 24. However, for the Intraday 1 (ID1) nomination cycle on December 24, interstate pipelines began to restrict underperforming meters. At that time, Con Edison was not notified of the specific reason for pipeline restrictions or reductions by marketers or producers. Due to the reduced supply and continuing high demand, the average meter station inlet pressure (reflecting the interstate pipelines' low pressure issues) for Con Edison declined rapidly and reached its lowest levels between the nomination deadline and scheduling for the December 24 ID1 cycle from 11:00 a.m. to 2:00 p.m. ET. The average pressure fell from 806 pounds per square inch gauge (psig) at 12:00 a.m. on December 23 to 441 psig at 2:00 pm on December 24. Con Edison Gas Control began implementing emergency measures after the interstate pipelines notified Con Edison that they had depleted their line pack, had no more ability to withdraw from storage, and would continue to have low interstate pipeline pressures until demand decreased. A likely contributing factor exacerbating pipelines' integrity issues was that some generators may have flowed in excess amounts over their confirmed nominations. The pipelines used line pack and gas from storage to meet the incremental demand, but as the Event progressed, the supplementary demand volumes in conjunction with continuing supply shortfalls led to low pressures and the reduction of confirmed nominations. Con Edison, given its downstream location near the end of the interstate pipelines, was disproportionately impacted by the deteriorating pipeline conditions, through no fault of its own.

e. LDC Gas System Emergency, Orders for Fuel Curtailments to Natural Gas-Fired Generation, and Public Appeals to Reduce Gas Demand

On December 24 at 1:26 p.m., Con Edison management declared an internal Gas System Emergency and dispatched its LNG facility, which ramped up to maximum dispatch, because the interstate pipelines serving Con Edison's citygate said that their pressures were not recovering. Later that day, at 2:14 p.m., Con Edison Gas Control declared Gas System Condition Red, which meant that "gas supply through gate station(s) . . . [was] . . . severely limited or completely interrupted resulting in imminent risk to more than 500 services." This Condition Red remained in place until December 26 at 10 a.m. In accordance with its "Guidelines for Major Contingencies on the Gas System" specification, Con Ed "order[ed] electric and steam generation stations to . . . completely curtail gas use." Con Edison had already dispatched its LNG Plant at 2 p.m., another step allowed under Gas System Condition Red. At 6:30 p.m. that evening, Con Edison issued a public appeal to reduce demand. Under the specification for Limiting Gas Use and Load Shedding During a Supply Curtailment or Emergency, Con Edison had 11 steps to mitigate a supply shortage or to limit gas during an emergency, which progresses from taking steps to increase the supply of natural gas to firm customer load shedding. Con Edison implemented actions through at least step 7, public appeals to reduce demand, before the Gas System Emergency abated. Figure 65 shows the average meter station inlet pressure on December 21-27, relative to the declaration of the Gas System Emergency and Gas System Condition Red. Figure 66, below, shows how the meter station inlet pressures for the five interstate pipelines serving Con Edison's citygate declined precipitously on Christmas Eve, before recovering on Christmas through December 27.

Figure 65: Con Edison Average Meter Station Inlet Pressure (PSIG), December 21 - 27, 2022

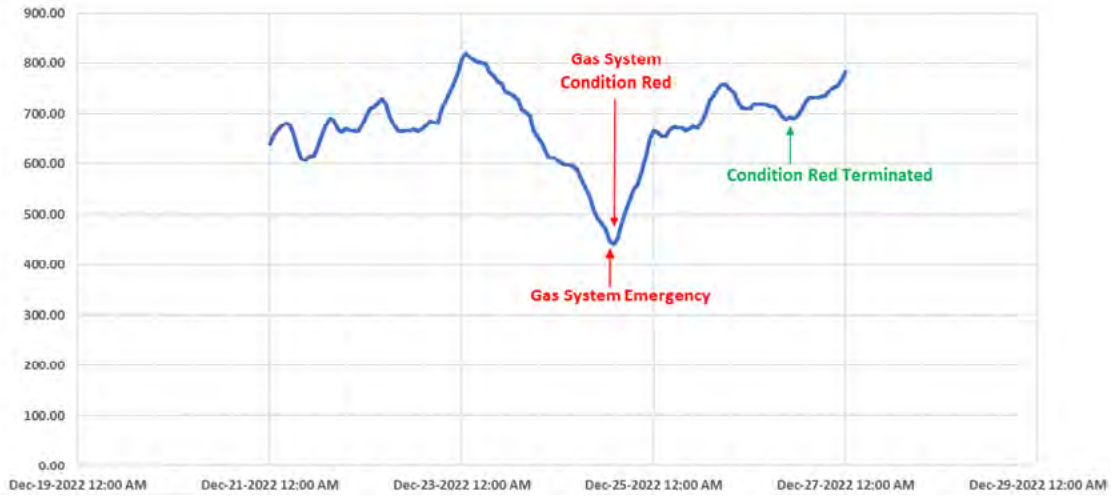
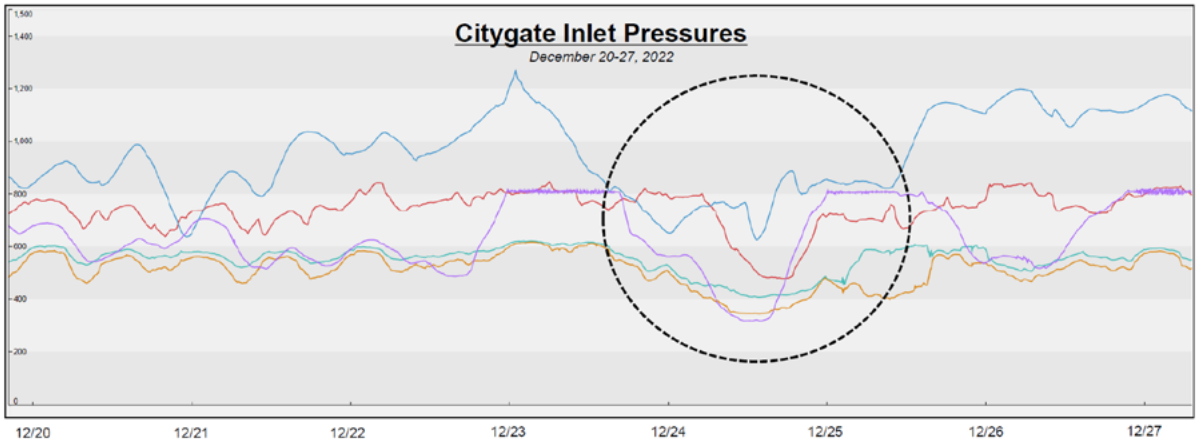


Figure 66: Con Edison Citygate Inlet Pressures, December 20 - 27, 2022



Efforts to address the situation continued on Christmas Day. Con Edison ramped down its LNG facility due to increasing pipeline pressures at its citygate and to preserve asset inventory, placing the LNG facility back on standby status at 8:13 a.m. Pressures at the citygate were recovering but the pipelines reported in a 7 a.m. call that line pack was still depleted. On December 26, Con Edison finally terminated its Gas System Condition Red.

C.Post-Event Actions by Affected Entities, Government Agencies and State Governments

1. ACTIONS BY AFFECTED ENTITIES

Several of the affected entities later conducted comprehensive reviews of the performance of their systems during Winter Storm Elliott. TVA created an "After Action Report" which included several recommendations to improve energy supply, real-time load forecasting and operations, emergency protocols, and customer and stakeholder engagement.[194] TVA has committed to adding 10,000 to 14,000 MW of new generation by 2030 to help meet demand. It is currently in the process of building 3,800 MW of new generation, including solar energy, energy storage, combustion turbines, and combined-cycle natural gas. It is also investing in infrastructure, enhancing its transmission systems, and building a new Systems Operations Center.[195]

PJM prepared an "Event Analysis and Recommendation Report," outlining the lessons learned from Winter Storm Elliott and improvements it plans to make.[196] These included improving generator performance, enhancing forecasting and modeling, and tackling long-standing gaps in gas-electric coordination. PJM is working on developing improvements through its Critical Issue Fast Path stakeholder process. PJM recently submitted proposed enhancements to the capacity market rules that address certain recommendations from its report, including, but not limited to, enhanced risk modeling, refined resource accreditation, updates to the balancing ratio, and changes to bonus eligibility for Demand Resources and Energy Efficiency Resources.[197]

LG&E/KU prepared two event summary reports, one for its Generation, Transmission and Distribution operations, and one for its Gas operations. It is looking at potential process improvements, such as public messaging and projects at plants to minimize valve freezing and other cold weather impacts.[198] Santee Cooper developed a historical average forced outage rate for units during extreme events to estimate how much additional reserves should be considered during this type of event.

2. ACTIONS BY GOVERNMENT AGENCIES AND STATE GOVERNMENTS

On August 25, 2023, the South Carolina Office of Regulatory Staff filed a report titled "Inspection and Examination Report of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC: December 2022 Winter Storm Outages and Blackouts."[199] The report identified five key causes for the rolling outages (firm load shed), which impacted over 500,000[200] customers across North and South Carolina, ranging from three to ten hours each: (1) Duke[201] significantly underestimated demand, failed to update its forecast estimates, and did not make

194 Tennessee Valley Authority After Action Report, at 20-21, https://bloximages.newyork1.vip.townnews.com/local3news.com/content/tncms/assets/v3/editorial/4/3e/43e4b436-eb67-11ed-a87a-530b1c4c2bd9/645537f5cd9d7.pdf.pdf).

195 *Id.* at 22.

196 PJM, Winter Storm Elliott Event Analysis and Recommendation Report ("PJM Report"), pages 2-3, https://www.pjm.com/-/media/library/reports-notices/special-reports/2023/20230717-winter-storm-elliott-event-analysis-and-recommendation-report.ashx .

197 *See PJM Interconnection, L.L.C.,* Docket No. ER24-98-000 (Oct. 13, 2023); *PJM Interconnection, L.L.C.,* Docket No. ER24-99-000 (Oct. 13, 2023). PJM has stated that it will continue to engage with stakeholders on recommendations from the PJM Report.

198 *Talking Points*,https://lge-ku.com/employee-resources/ce/talking-points/2023/01/winter-storm-elliott (last visited Oct. 26, 2023).

199 Inspection and Examination Report of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC December 2022 Winter Storm Outages and Blackouts, Docket No. ND-2023-1-E (Aug. 25, 2023), ec372380-8639-406e-816e-fc9fe0d45cfd (sc.gov)

200 https://news.duke-energy.com/releases/duke-energy-updates-north-carolina-utilities-commission-on-winter-storm-elliott-emergency-outage-event#:~:text=CHARLOTTE%2C%20N.C.%20%E2%80%93%20Leaders%20from%20Duke,from%20occurring%20that%20way%20again

201 DEC and DEP.

supply planning adjustments; (2) Duke experienced multiple failures at various plants, some due to planned maintenance and others due to operational issues that forced them to shut down, such as cracks in the insulations and frozen instruments; (3) power purchases from neighboring utility companies were curtailed; (4) power generation contracted by other utilities failed; and (5) the automated software tool to manage the rotating outages failed, causing significant delays as Duke had to manually restore power. The report also discussed Duke's delay in communicating with customers. The outages began between 6:15 and 6:25 a.m. on December 24. The report found Duke began notifying customers one hour later. The investigation also found Duke told customers the timeframe for power restoration would be 30 to 60 minutes, when in fact it took several hours.

Ultimately, the report found that there is "room for improvement" in Duke's cold weather preparedness plans for its generation facilities. The investigation made several recommendations, including ensuring that doors and louvers that could expose equipment to the elements are left closed, and installing heaters. The investigation also recommended Duke enhance staffing and the frequency of operators making rounds during severe winter weather events. On August 29, 2023, Duke submitted a letter[202] to the Public Service Commission responding to the report, which took issue with several of its findings, including with the report's statement that Duke failed to respond to supply adequacy risk, asserting that Duke did respond and made purchases to increase operating reserves where they were forecasted to be below target. Duke also said that the models used by the industry to forecast power demand "look backwards in time" for similar circumstances, and that a similar day in December did not exist. However, the letter stated that Duke has created a corrective action plan, and that it has completed 76 of the 101 action items in the plan, with the action items in progress.

The Kentucky Public Service Commission has been using a preexisting docket regarding approval of a demand side management plan and approval of fossil fuel-fired generating unit retirements to obtain data from LG&E/KU regarding the Event, but has not issued any findings.[203] On February 17, 2023, the Kentucky Attorney General sent LG&E/KU an initial request for information.[204] The inquiry asked the companies to "[p]rovide a detailed, thorough and comprehensive explanation regarding the causes of the rolling blackouts [firm load shed] the Companies instituted during Winter Storm Elliott[…]." On March 10, 2023, LG&E/KU provided their responses to the initial data requests.[205] This included a summary of events prepared by LG&E/KU.[206] In this summary, the companies stated that the rolling blackouts were caused by interstate gas pipeline pressure limitations, mechanical issues, and other cold weather issues. The companies explained that the projected net peak load was far lower than the actual peak load on December 23. Three of the companies' units were offline during this time and not expected to be needed. The supplier for two of the plants also failed to meet its contractual obligations, and there were interruptions in energy deliveries. LG&E/KU explained that as the conditions across the regional grid began to deteriorate, they executed their Capacity and Energy Emergency Operating Plan in order to restore system balance.

202 36b057d1-aba3-47d5-9bbe-4a9f2d4fbb0f (sc.gov)

203 The record was closed as of September 15, 2023, and the Commission stated that it will issue a decision after October 5, 2023. The docket did not show a decision as of the morning of October 30. *Winter Storm Elliott Events in the LG&E and KU Balancing Authority Area (BAA)*(Dec. 24-25, 2022), https://psc.ky.gov/pscecf/2022-00402/rick.lovekamp%40lge-ku.com/03102023103319/03-AG_DR1_LGE_KU_Attach_to_Q13%28l%29_-_Att_1_Winter_Storm_Elliott_LKE_Event_Summary.pdf.

204 *Kentucky Coal Association First Data Request (filed Feb. 17, 2023)* https://psc.ky.gov/pscecf/2022-00402/mmalone%40hdmfirm.com/02172023095137/First_Data_Requests_to_Companies.final.pdf; *Attorney General Data Requests* (Feb.17, 2023), https://psc.ky.gov/pscecf/2022-00402/rateintervention%40ky.gov/02172023023845/23..02.17_AG-DR-1_2022-00402_FINAL.pdf.

205 *Kentucky Utilities Co. & Louisville Gas and Electric Co. Response* (Mar. 10, 2023),https://psc.ky.gov/pscecf/2022-00402/rick.lovekamp%40lge-ku.com/03102023103319/02-AG_DR1_LGE_KU_Responses.pdf.

206 *Winter Storm Elliott Events in the LG&E and KU Balancing Authority Area* (BAA) (Dec. 23-24, 2022), https://psc.ky.gov/pscecf/2022-00402/rick.lovekamp%40lge-ku.com/03102023103319/03-AG_DR1_LGE_KU_Attach_to_Q13%28l%29_-_Att_1_Winter_Storm_Elliott_LKE_Event_Summary.pdf.

IV. ANALYSIS AND FINDINGS

A. Overview of Event Causes

Three causes accounted for 96 percent of the generating unit outages, derates or failures to start, based on number of MW: Mechanical/Electrical, Freezing, and Fuel Issues, as shown in Figure 67. Natural Gas Fuel Issues, (the larger portion with small dots in the orange pie segment) were 20 percent of all causes (and 83 percent of outages caused by Fuel Issues).[207] Figure 68, below, illustrates the generating unit outages by fuel type over the course of the Event. Natural gas-fired units represented 47 or 63 percent of the incremental unplanned generation loss, based on number of outages or MW, respectively.[208] Unplanned outages of natural gas- and coal-fired generating units began to rise on December 22 and rose steadily into December 23. Early on December 23, the rate of outages of natural gas-fired generating units rose sharply, and this trend continued throughout December 23. This is consistent with what Balancing Authorities told the Team, especially in PJM and MISO: that multiple natural gas-fired generating units reported their inability to perform during that period, in many cases, only when called to find out why they had not come online.[209] Natural gas-fired generating unit outages peaked at nearly 60,000 MW for the Event Area by midday on December 24. Natural gas-fired generating units played such a large role in the Event due to the large percentage of natural gas-fired generation in the Event Area (nearly 42 percent, see Figure 11), and the multiple outage causes which affected this fuel type (Fuel Issues, Freezing Issues and Mechanical/Electrical Issues not directly caused by freezing). According to the NAESB Report, "trends in electrification coupled with the growth in renewable resources and the retirement of coal-fired generation, likely mean there will be a greater reliance upon electricity produced by natural gas as a balancing resource."[210]

Freezing Issues caused 31 percent of all generating unit outages, and over 75 percent of Freezing Issues occurred at ambient temperatures that were above the GOs' documented operating temperatures.[211] Both open-frame generating units, common throughout the south, and natural gas production infrastructure, with its associated water, are known to be vulnerable to freezing. In addition, wind turbines are known to be vulnerable to blade icing because of freezing precipitation. Coal-fired units can be vulnerable to frozen coal piles or difficulty processing wet coal, especially if the coal piles remain undisturbed during periods of freezing precipitation.[212] The extent to which generating units of all types still experienced outages, derates and failures to start to Freezing Issues continues to be a major concern. Freezing Issues and Fuel Issues combined to cause 55 percent of all unplanned generating unit outages, derates and failures to start during the Event, as shown in Figure 67 below (as measured by MW). Mechanical/Electrical Issues, responsible for an additional 41 percent of outages, derates and failures to

207 Natural Gas Fuel Issues include the combined effects of decreased natural gas production; cold weather impacts and mechanical problems at production, gathering, processing and pipeline facilities resulting in gas quality issues and low pipeline pressure; supply and transportation interruptions; curtailments and failure to comply with contractual obligations. Additionally, it includes shippers' inability to procure natural gas due to tight supply, prohibitive, scarcity-induced market prices, or mismatches between the timing of the natural gas and energy markets.

208 Unless otherwise indicated, within this section values expressed as percentages correspond to the total amount of incremental generation lost—*i.e.* unavailable MW—as reflected in data provided by generating unit owners and/or operators. *See* Appendix C.2 for a breakdown of outages, derates and failures to start by fuel type, among other analyses.

209 *See* Section III.B.1.a) regarding MISO and PJM experiences regarding generator reported fuel issues on December 23.

210 NAESB Report at 67.

211 *See* note 61 for an explanation of the various methods GOs can choose to document an operating temperature and how the Team calculated this statistic.

212 This can be mitigated by continuous movement of the coal pile (using bulldozers or similar equipment) during freezing precipitation/extreme cold weather conditions.

start, also increased as temperatures fell and decreased as temperatures rose, but unlike Freezing Issues, the method by which the cold affected the generating unit was less obvious.

Figure 67: Total MW Loss of Incremental Generation Outages, Derates, and Failures to Start (Outaged MW) by Cause, December 21-26, Total Event Area

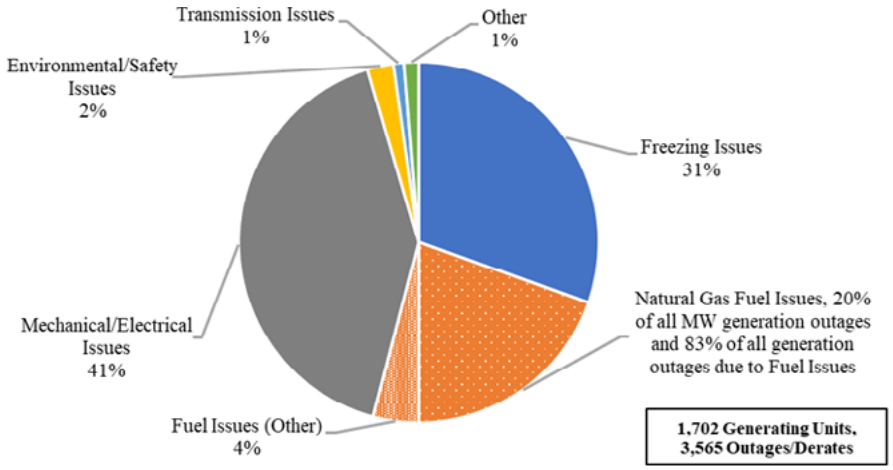


Figure 68: Generation Outages, Derates, and Failures to Start (MW) by Fuel Type, December 21-26, Total Event Area

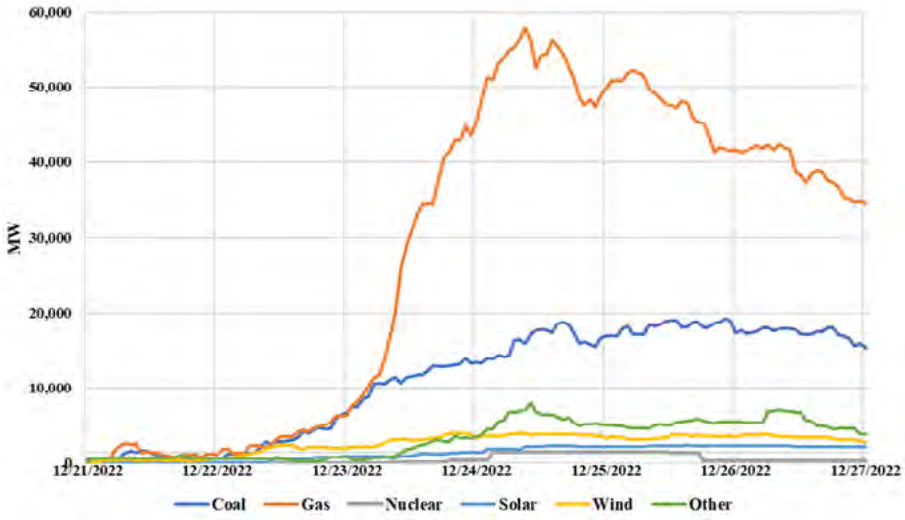
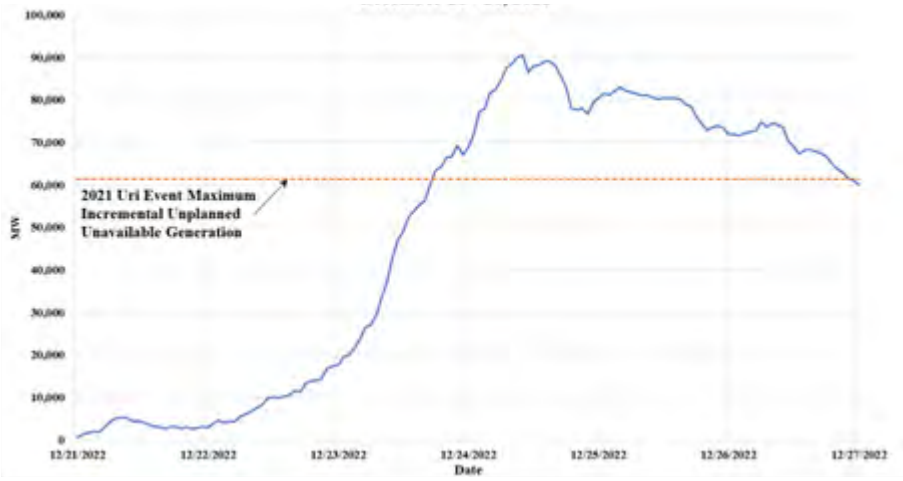


Figure 69: Incremental Unplanned Coincident Unavailable Generation in the Event Area, December 21-26, Total Event Area



At its worst point, the U.S. portion of the Eastern Interconnection had over 127,000 MW of generating outages, including outages that began before the Event, equivalent to **18 percent** of the U.S. portion of the anticipated resources in the Eastern Interconnection.[213] The peak coincident incremental unplanned unavailable generation in the Event (90,500 MW), as shown in Figure 69, above, was roughly 50 percent larger than the peak magnitude of coincident incremental unavailable generation during Winter Storm Uri (represented by the red dotted line in Figure 69), although the Uri event lasted more than twice as long (13 days versus six days).

213 According to the NERC 2022-2023 Winter Reliability Assessment. *See* note 12.

B. Causes of Generating Unit Outages During the Extreme Cold Weather

1. SUMMARY

An analysis of the data collected in connection with Winter Storm Elliott reiterates the relationship between the onset of freezing temperatures and the rise of generation loss caused by Freezing Issues, by Mechanical/Electrical Issues strongly correlated to declining temperatures, or by Fuel Issues whose root cause can be traced to the onset of extreme cold weather, as shown in Figure 70, below.

Winter Storm Elliott, and its impact on generation, is notable for two material reasons.

First, the scale of generation lost during Winter Storm Elliott is unprecedented, with a peak incremental unplanned generation loss totaling 90,500 MW. This reflects generation loss at 1,702 individual generating units spread over 3,565 discrete unplanned outages or derates. This incremental unplanned generation loss during Winter Storm Elliott, after the catastrophic effects of Winter Storm Uri just one year earlier, raises a concerning alarm about the ability of the grid to handle extreme cold weather events.

Second, Mechanical/Electrical Issues related to extreme cold weather events (as distinguished from Freezing Issues) rose as temperatures fell, a pattern seen in every extreme cold weather inquiry event since 2018. The 2021 Report noted that as temperatures fell, generation losses attributed to Mechanical/Electrical Issues increased[214] and that "[i]n the 2018 event, a similar pattern was evident—the total generating unit outages were correlated with temperatures—again, as temperatures fell, the incidence of unplanned outages and derates increased."[215] As reported in the 2021 Report, these outages may be caused by the impact of extreme cold weather on mechanical and thermal stress, thermal cycling fatigue and other effects of cold weather such as embrittlement and gelling of fuels and lubricants.[216]

2. MECHANICAL AND ELECTRICAL ISSUES

a. Summary Analysis

Overall, generating units reported 1,418 unplanned outages, derates or failures to start for various reasons linked to Mechanical/Electrical Issues – accounting for 40 percent of all generation losses reported during the Event and peaking at more than 31,000 MW of incremental unplanned generation loss during the Event. Most manifested as forced outages (48 percent) or forced derates (43 percent).

Within the Mechanical/Electrical Issues category, the most significant individual sub-cause of outages was Equipment Failures/Issues by a wide margin (72 percent). Other than Equipment Failures/Issues, the only other sub-cause within the Mechanical/Electrical Issue category that had a material presence (approximately 10 percent) was Control System Issues. No other single sub-cause identified by GOs/GOPs materially contributed to lost generation attributable to Mechanical/Electrical Issues.

b. Relationship Between Freezing Conditions and Mechanical/Electrical Issues

As indicated in Figure 71, below, over 80 percent of the incremental unplanned MW lost to Mechanical/Electrical Issues occurred when generating units began to experience below-freezing temperatures.

214 *See* Recommendation 11 and Figure 105 in 2021 Report.

215 *See* 2021 Report at 217.

216 *See* 2021 Report at 215-217.

Figure 70: Incremental Unplanned Unavailable Generation in the Event Area, Primary Event Causes, December 21 - 26, 2022

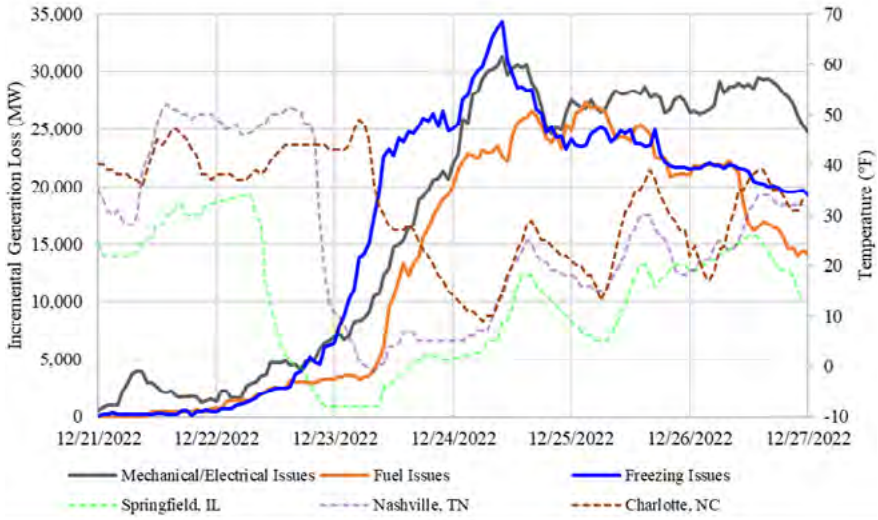
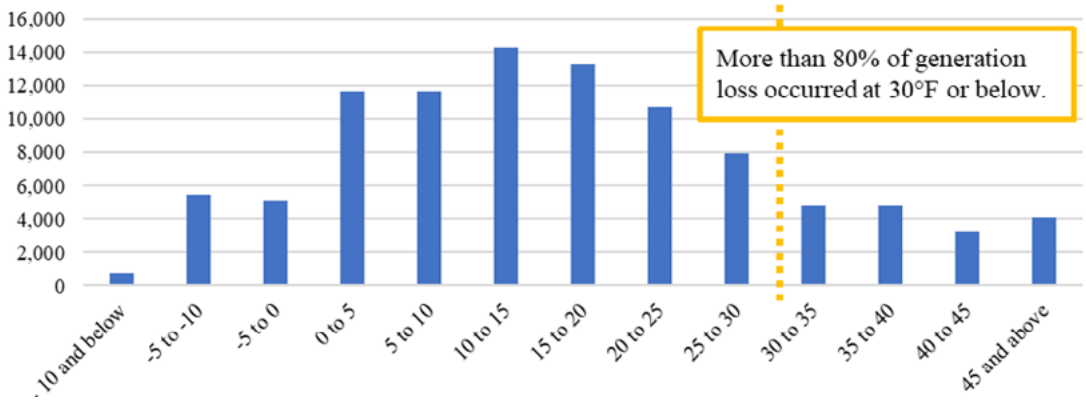
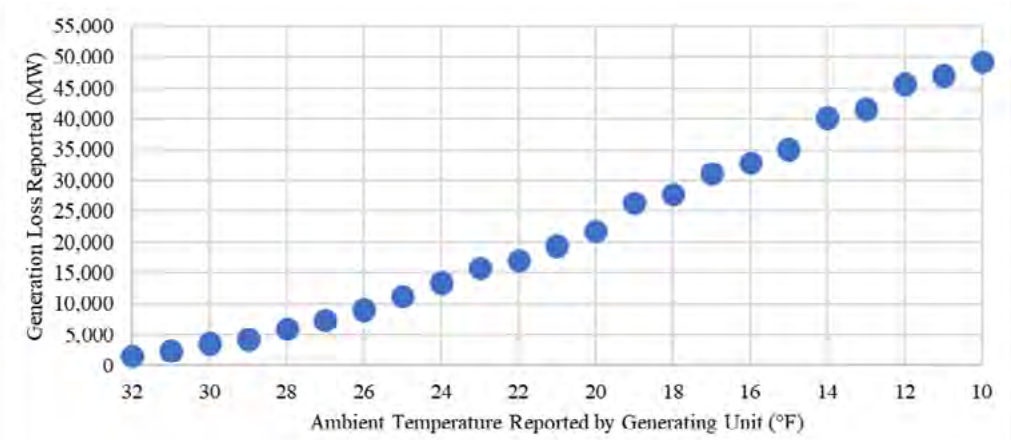


Figure 71: Generation Loss, Mechanical/Electrical Issues by Temperature (°F) Reported at Time of Outage, December 21-26 2022



As illustrated below, generating units steadily lost generation due to Mechanical/Electrical Issues as temperatures declined. In aggregate, generating units reported more than 49,000 MW of lost generation due to Mechanical/Electrical Issues in temperatures between 32 degrees and 10 degrees, as seen in Figure 72, below.

Figure 72: Cumulative Gross Generation Loss, Mechanical/Electrical Issues by Temperature (°F) Reported by Generating Unit, December 21-26, 2022

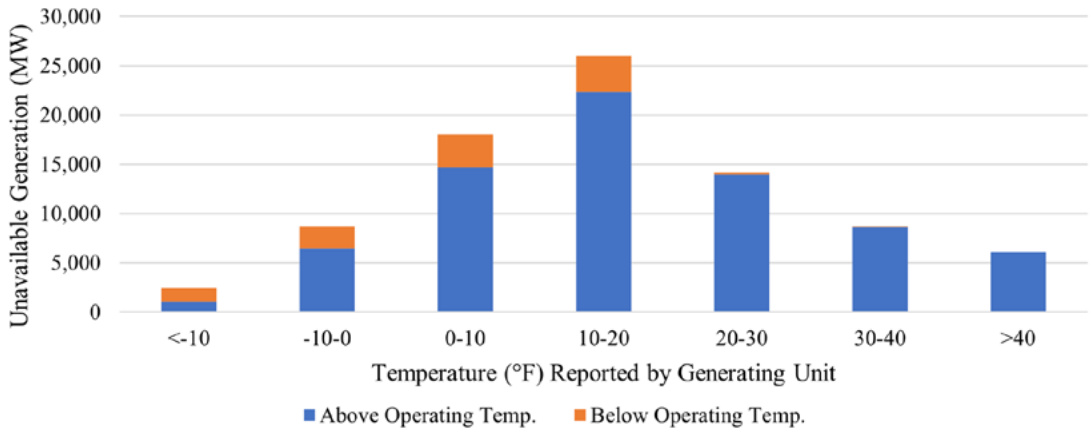


Not every generating unit that experienced a Mechanical/Electrical Issue in below-freezing conditions during Winter Storm Elliott did so *because of* extreme cold weather conditions. The Team believes it is reasonable to conclude that a material portion of Mechanical/Electrical Issues are causally connected to these extreme cold weather conditions. This relationship is supported by reasonable inferences drawn from the numerical data provided by generating units, as well as by narrative responses provided by units explaining their Mechanical/Electrical Issues. Some units that reported Mechanical/Electrical Issues in below-freezing conditions explicitly linked those Mechanical/Electrical Issues to the impacts of cold weather. For example, one generating unit reported that generation was lost because "[g]enerator gas temperature became too low due to ambient temperature." Another claimed that the generating unit "would not start due to oil temperature too low." However, even without considering these explicit claims, many units reported a range of issues that Team members believe, based on their review of the data provided, were likely or probably caused by cold weather conditions. For example:

- Increased oil viscosity with colder ambient temperature (or colder cooling water) was a common issue in the Event:
  - Losses in fuel oil pressure can be caused by cold-induced high viscosity, leading to inability to operate a unit on fuel oil.
  - Wind turbine generators may also suffer from high oil viscosity (lubricant or hydraulic controls), creating pitch problems seen in the Event.
- Many generating units reported material dimensional changes (*i.e.,* shrinkage) during the Event, which may add stress in mechanical systems.

The data also suggest that the ***extreme*** nature of these cold weather events—that is to say, unusually quick drops in temperature, high winds and/or atypical combinations of conditions—may play a role in generation loss due to Mechanical/Electrical Issues.

Figure 73: Generation Loss, Mechanical/Electrical Issues, December 21-26, 2022



As shown in Figure 73, above, comparing generating units' documented operating temperature to the ambient temperature conditions that they reported while experiencing Mechanical/Electrical Issues revealed a clear and disturbing outcome. A substantial majority of generation losses due to Mechanical/Electrical Issues (87 percent) occurred at an ambient temperature above the generating units' documented operating temperature.[217]

Using only the units' ambient design temperature, for those units that provided that temperature, nearly 39,000 MW of generation was lost due to Mechanical/Electrical Issues where units (a) reported freezing or below-freezing ambient temperatures in connection with the generation loss, (b) provided an ambientdesign temperature, and (c) where the ambient design temperature was 10 degrees or more below the temperature at which the Mechanical/Electrical Issue occurred.

The data available suggests that some portion of the Mechanical/Electrical Issues outages may have been more appropriately categorized as Freezing Issues, and that the remainder illustrate a relationship between mechanical/electrical component malfunction and temperature that, to date, has not been fully explored or understood. Given the large percentage (40 to 41 percent, by number of units and MW, respectively) and MW losses (150,569 MW) caused by Mechanical/Electric Issues, better understanding the relationship between mechanical/electrical component malfunctions and temperatures is critical to improving future extreme cold weather performance by generating units. The Team believes an improved understanding can and should be evaluated on both a unit-by-unit basis—which the Team hopes can be obtained, in part, through the practices advanced in Recommendation 1—and on a systematic basis—through the study advanced in Recommendation 2.

3. FREEZING ISSUES

a. Summary Analysis

Data collected from generating units related to Freezing Issues during Winter Storm Elliott demonstrated similar trends to the data analyzed in the 2021 Report. Overall, units reported 1,030 distinct Freezing Issue-related

217 This figure is based only on units that provided ambient temperature conditions for their units experiencing outages—not all units reported ambient temperatures as requested. It is also based on the highest of the (up to three) temperatures that the entity could have provided: ambient design temperature, historical operating temperature, or current cold weather performance temperature determined by an engineering analysis. *See* also, note 61. Other materials related to the Report, including the presentation given by Team members on September 21, 2023, stated that nearly 80 percent of Mechanical/Electrical Issues occurred above a generating units' minimum operating temperature. That figure was based on a conservative earlier analysis of the data collected.

unplanned outages, derates, or start-up failures, which, combined, caused 110,962 MW of generation loss at various times during the Event,[218] and as illustrated in Figure 67, above, were 31 percent of the total MW of generation outages, derates, and failures to start during the Event. Variations by approximate U.S. geographic region basis in the Event Area for all unplanned generation MW outages due to **Freezing Issues** (as compared to other outage causes, e.g., Mechanical/Electrical Issues or Fuel Issues) are shown in Figure 74, below.

Figure 74: Variation by Approximate U.S. Geographic Region in the Event Area for Unplanned Unavailable Generation (MW) due to Freezing Issues

Approximate U.S. Geographic Region	Unplanned Unavailable Generation Due to Freezing Issues(Percent of MW)
New York	5%
MidAtlantic/Midwest	27%
Central/South Central	33%
Southeast	43%
Total Event Area	**31%**

Most BA footprints located in the southeast portion of the Event Area experienced higher percentages of unplanned generation outages due to Freezing Issues as compared to other geographic regions––especially compared to the northern portions of the Event Area.[219]

The specific types of Freezing Issues were similar to those seen during Winter Storm Uri. A substantial number of outages were linked to frozen transmitters, frozen sensing lines, or other frozen instrumentation – approximately 42 percent of all generation lost to Freezing Issues (Figure 75, below). As in the 2021 event, Freezing Issues caused a large percentage of unplanned wind generation outages and derates — 53 percent (by MW) or 40 percent (by number of outages). Freezing Issues caused 75 percent (by MW) and 43 percent (by number of outages) of unplanned outages and derates of nuclear units. Historically, Freezing Issues have been rare in nuclear units, due in part to their enclosed design.[220]

b. Existing and Pending Reliability Standards

Two sets of mandatory NERC Reliability Standards applicable to GOs—NERC Standard EOP-011-2, and the forthcoming EOP-012-1—are of particular relevance here.

In August 2021, the Commission approved the adoption of EOP-011-2, effective April 1, 2023, as part of a package of cold weather Reliability Standards.[221] As part of these updates, EOP-011-2 was revised to make clear that the GO is the "entity responsible for compliance" with the extreme cold weather Reliability Standards. This

218 This value is distinct from the 90,500 MW of incremental coincident unplanned outages during the Event, which is was the level of unplanned generation outages, derates, and failures to start for all causes the grid operators in the Core Event Area were faced with at approximately 10:00 a.m. on December 24, 2022. The 111,000 MW represents the MW of generation capacity outages, derates, and failures to start that were due to Freezing Issues at various times during the entire Event, from December 21-26, 2022.

219 Open-frame generation facilities, which are common throughout warmer climates in the U.S., are designed and constructed without enclosed building structures to avoid excessive heat build-up in the summer but are more vulnerable to freezing. *See* 2011 Report, Appendix: Power Plant Design for Ambient Weather Conditions, and 2021 Report at 162.

220 *See* Appendix C.2., Additional Charts and Figures for Unplanned Generation Outages During Event, Unplanned Generation Outages by Fuel Type.

221 *See N.* Am. Elec. Reliability Corp., 176 FERC ¶ 61,119 at P 1 (2021).

required GOs to "develop, implement, and train on their extreme cold weather preparedness plans."[222]

Figure 75: Unavailable MW by Balancing Authority, Freezing Issues, December 21 - 26, 2022[223]

Equipment Category	Components and Systems Impacted	Event Count	MWs Outaged or Derated	
Turbine Blades	Icing on blades	127	6,281	5.7%
Instrumentation	Frozen transmitter	49	17,776	16.0%
	Frozen sensing lines	27	9,757	8.8%
	Frozen instrumentation	58	18,824	17.0%
Other Equipment Freezing Problems	Frozen equipment	27	4,388	4.0%
	Frozen valve	39	11,860	10.7%
	Frozen water lines	19	6,547	5.9%
	Frozen pipes	24	5,702	5.1%
	Equipment failure	57	8,026	7.2%
	Other freeze-related issue	173	21,668	19.6%

Requirement R7 requires each GO to "implement and maintain one or more extreme cold weather preparedness plan(s) for its generating units" linked to each unit's "design temperature, . . . historical operating temperature, or . . . current cold weather performance temperature determined by an engineering analysis."[224]

More recently, in February 2023, the Commission approved new Reliability Standard EOP-012-1 – Extreme Cold Weather Preparedness and Operations. The new standard builds on EOP-011-2, "enhance[] the reliable operation of the [grid] by requiring generator owners to implement freeze protection measures, develop enhanced extreme cold weather preparedness plans, implement annual trainings, draft and implement corrective action plans to address freezing issues, and provide certain extreme cold weather operating parameters to Reliability Coordinators, Transmission Operators, and Balancing Authorities for use in their analyses and planning."[225]

The crux of these standards is that generating units are expected to have an extreme cold weather preparedness plan tethered to one or more of the minimum operating temperatures associated with the unit – ambient design, historical operating minimums, or an extreme cold weather performance temperature determined by an engineering analysis. This minimum operating temperature is conveyed to that generating unit's Balancing Authority so that it may rely on the temperature information in connection with planning and dispatch decisions.

c. Operating Parameters Provided by Generating Units

The vast majority of generating units that provided data for this report had obtained an ambient design temperature, minimum historical operating temperature, or extreme cold weather performance temperature determined by an engineering analysis. Of generating units that responded to the data request,[226] 67 percent

222 *Id.* at PP 4, 6.

223 "Other freeze-related issue" includes freeze-related sub-causes external to the generating unit such as frozen coal or ice on transmission lines.

224 *See* EOP 011-2 R7.3.2. RSCompleteSet.pdf (nerc.com).

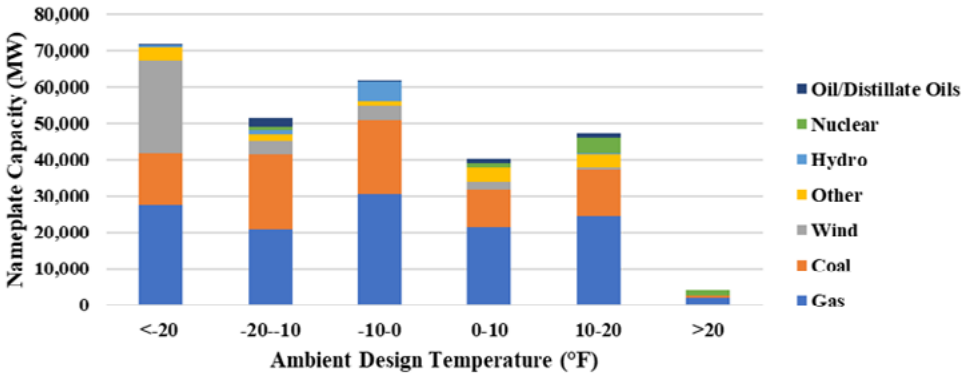
225 N. Am. Elec. Reliability Corp., 182 FERC ¶ 61,094 at P 36 (2023). The effective date for Reliability Standard EOP-012-1 is October 1, 2024.

226 Unless otherwise noted, percentages in this section are based on the nameplate capacity of the generating units that provided the necessary data.

reported a minimum design temperature. A slightly higher percentage, 74 percent, reported a historical minimum operating temperature, and very few units, only eight percent, reported an extreme cold weather performance temperature determined by engineering analysis.

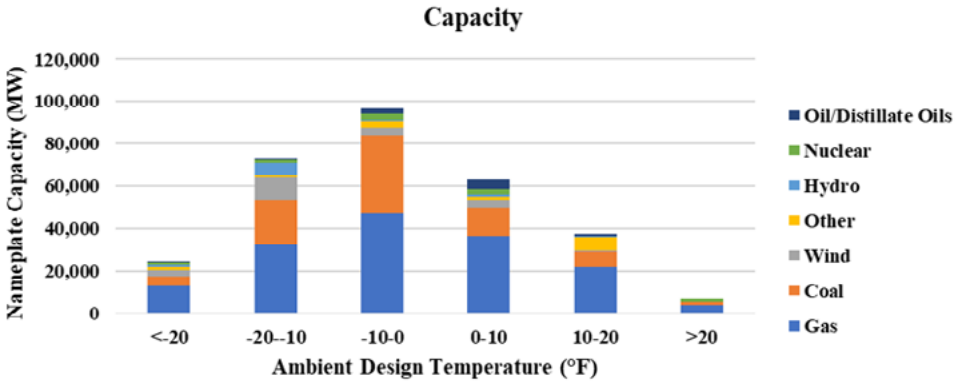
As illustrated in Figures 76 and 77, below, approximately two-thirds of the generating unit capacity (measured by nameplate MW) that responded with an ambient design temperature or a historical minimum operating temperature indicated a design temperature or a historical minimum operating temperature below zero degrees. More than 80 percent of units responded with an ambient design temperature below 10 degrees. Ambient design temperatures of coal units were spread across temperatures ranging from less than -20 up to 20 degrees. Similarly, ambient design temperatures of natural gas units were spread mostly across those ranges, except for a few units that had temperatures over 20 degrees. Over 80 percent of wind and one hundred percent of the solar units reported ambient design temperatures below zero degrees.

Figure 76: Ambient Design Temperature by Fuel Type and Total Capacity



The primary takeaway from this data is that of the units that reported outages, derates, or failures to start during the Event, nearly 84 percent of the total unit capacity reported a "documented operating temperature"—that is to say, the highest of their stated design temperature, historical minimum operating temperature, or an extreme cold weather performance temperature determined by an engineering analysis, of 10 degrees or lower. Although these data suggest that the generating units impacted by Winter Storm Elliott were, at a minimum, designed to operate or had successfully operated in extreme cold, over 63,000 MW (over 75 percent) of generation had outages, derates or failed to start due to Freezing Issues at temperatures above their documented operating temperature during the Event, as discussed below.

Figure 77: Historical Minimum Operating Temperature by Fuel Type and Total Capacity

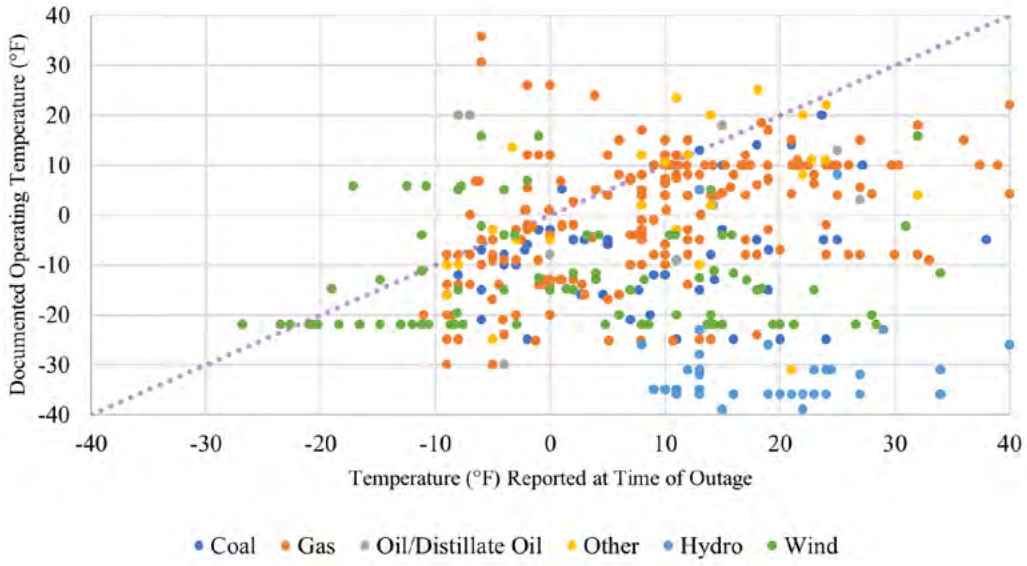


d. Freezing Above Documented Operating Temperature

A substantial majority of generation loss by units that reported Freezing Issues occurred at temperatures that were above the documented operating temperature thresholds incorporated into EOP-011-2, Requirement R7. Generating units of all primary fuel types—with the exception of a small number of generating units whose primary fuel type was oil—reported Freezing Issues well above their documented operating temperature.

In sum, generators did not perform according to their documented operating temperature. The scatter plot (Figure 78, below) compares the ambient temperatures reported by generating units with Freezing Issues to the documented operating temperature of that unit. The diagonal line represents the points at which the ambient temperature and documented operating temperature are equal. A substantial majority all of the generating unit outages plotted fall below (or the right of) the line, meaning that their outage occurred at temperatures above their documented operating temperature.

Figure 78: Temperature Reported at Time of Outage versus Documented Operating Temperature for Generators with Freezing Issues



e. Impact of Wind and Precipitation on Freezing Issues

The Team reviewed data to evaluate the impact of other weather conditions—wind and precipitation—on generating units reporting Freezing Issues. Wind can have a cooling effect that may cause unexpected Freezing Issues below ambient design temperatures. Precipitation coupled with freezing temperatures can also greatly impact generating unit operations during extreme cold weather events. This review did not reveal significant or clear trends—in part because the low number of units experiencing Freezing Issues below their minimum operating temperature frustrates a comparative analysis on those grounds.

On average, the wind speeds reported for units that had Freezing Issues above their document operating temperature averaged 16 mph, while wind speeds reported for units that had Freezing Issues below their minimum operating temperature averaged 20 mph. These two data points suggest that the cooling effect of wind did not substantially affect whether a given generating unit would experience a Freezing Issue above or below its minimum operating temperature. See Figure 79, below.

Precipitation affected whether a unit would fail above its documented operating temperature for some fuel types, such as oil and wind, but not for others fuel types such as natural gas and coal. Figure 80 below, breaks down performance by fuel type.

Protecting generator cold weather critical components from extreme cold weather is not complicated. Freeze protection measures -- such as heat trace, insulation, wind breaks, or targeted roofing to protect insulation from getting wet—have been used for years to prevent failure. What makes the difference between successful operation for the duration of an extreme cold weather event and unplanned outages due to freezing? Observations over multiple extreme cold weather events suggest that improved outcomes are associated with attention to detail, consistency in implementing the plan for protecting generator cold weather critical components, and preventing complacency when preparing for winter. Several entities involved in the Event shared stories about generating units lost because seemingly insignificant areas were insufficiently protected. For example, one entity had a false floor in its unit, and did not realize that a pipe was not insulated beneath the floor. The small section of pipe under the floor froze and caused the unit to trip.

Figure 79: Average of Wind Speed Reported for Units with Freezing Issues Comparing Above/Below Documented Operating Temperature

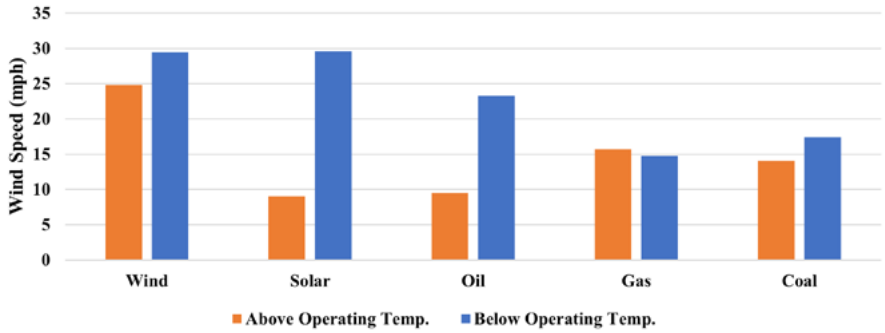
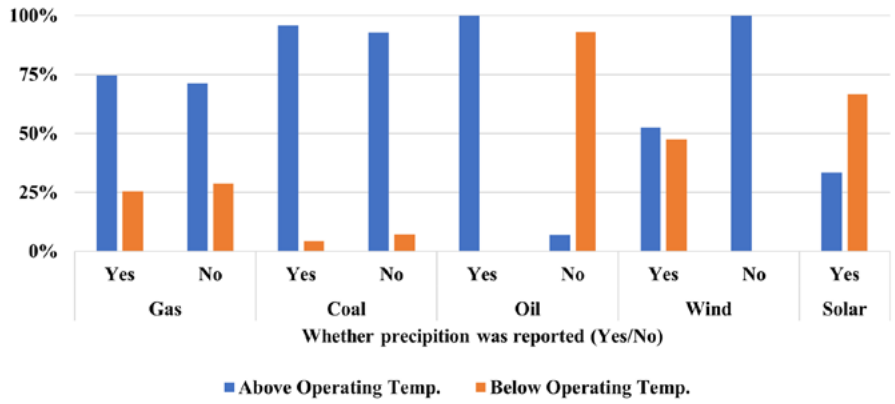


Figure 80: Precipitation Reported for Units with Freezing Issues Comparing Above/Below Documented Operating Temperature



The Lesson of Consecutive Cold Weather Events: Consistency, Attention to Detail, and a Sense of Urgency are Critical to Effective Cold Weather Preparation

As described more fully below, there have twice been extreme cold weather events that resulted in no load loss shortly after a similar event during which firm load was shed.

The first set of events occurred in February, 2011. In early February 2011, ERCOT, Salt River Project, and El Paso Electric Company needed to shed firm customer electric load, over 4,000 MW total, due in part to generating unit outages caused by freezing. On February 10, 2011, cold temperatures returned to Texas. "Actual temperatures in the ERCOT region averaged a low of 19 degrees with a 12-degree wind chill."[227] Yet ERCOT did not shed either firm or interruptible load despite setting a new winter peak of 57,915 MW.[228]

The 2011 Report found that "ERCOT avoided service interruptions on February 10 largely because there were far fewer forced outages."[229] While weather differences also played a role,[230] **the 2011 report found that "repairs made and protective measures taken during the event of February 2 remain[ing] in place" were a significant factor.**[231] GOs/GOPs had addressed vulnerabilities including "re-routing piping or moving vulnerable equipment, correcting transformer oil levels at wind farms, and adding freeze-resistant chemicals.

227 2011 Report at 99.

228 2011 Report at 99.

229 2011 Report at 99.

230 The February 10 low of 19 degrees was the same as the February 2 low, however the wind chill was lower on February 2 and low temperatures during the earlier event were more persistent, remaining in the low twenties for four days with wind chills between 10 and 14 degrees. 2011 Report at 99.

231 Generator owners had "installed wind breaks, including tarps or enclosures, added portable heaters or heat lamps, repaired or added insulation, and repaired or added heat trace. One generator changed its procedures for monitoring the reliability of its heat trace. Some generators also continued their increased level of staffing to address freeze protection issues, and others changed elements of their control logic to prevent units from automatically tripping." 2011 Report at 100.

At least five generators kept units running, started units earlier or took other measures to keep from having a cold start. After so many static sensor and other lines froze the week before, some units left water lines draining, or took other measures to keep water flowing."[232]

The second set of events occurred in January 2014 and February 2015. On January 6 and 7, 2014, parts of the Eastern Interconnection experienced a "polar vortex," with "temperatures 20 to 30 [degrees] below average, and some areas [35 or more degrees] below their average temperatures."[233] As NERC noted in its "Polar Vortex Review," "these lower temperatures had a drastic impact on load, with many of the RCs/BAs [e.g., MISO, PJM, TVA, VACAR-South RC (including Duke), and Southern/Southeastern-RC] reporting record or near-record winter peak demands. PJM exceeded its historic winter peak on both January 7 and January 8, 2014, and MISO reported that they exceeded their historic winter peak for three straight days (January 6–8, 2014)."[234] Due to the high loads and unplanned generating unit outages, including an estimated 19,500 MW of generation outages due to "cold weather conditions," and "a significant reduction of generating capacity due to curtailments and interruptions of natural gas delivery," affected entities needed to use "load reduction procedures such as voltage reduction, interruptible loads, and demand-side management," and in one case, to shed 300 MW of firm load, to maintain system reliability.[235]

A little more than a year later, severe cold temperatures hit the Eastern Interconnection again. "Numerous cities [in the Eastern Interconnection] hit their daily low-temperature records during February 2015. Due to the low temperatures and associated high electricity demand for heating needs, PJM set a new wintertime peak demand record of 143,086 megawatts the morning of February 20, 2015 . . . The new peak record surpassed the previous all-time winter peak . . . set [during the Polar Vortex]. Although the new record winter peak was set during this time frame, no emergency demand response or any other capacity emergency actions were required. Many other areas also set all-time record winter peaks in 2015."[236] PJM and DEP set winter peak load records in 2015 that remained unbroken during the Event, and DEC broke its 2015 record by less than 150 MW.[237] Yet "[g]enerator performance in . . . February of 2015 showed improvement over 2014 with improved overall forced outage rates." or example, PJM's forced outage rate dropped from 22 percent to 13.4 percent.[238] NERC attributed this improvement to "steps generation owners . . . initiated after the winter of 2014."[239] NERC used GADS[240] data to compare winter 2015 equivalent forced outage rates (EFOR) to those during the polar vortex in 2014 and to previous years' rates.[241]

232 2011 Report at 100.
233 Polar Vortex Review at iii.
234 Polar Vortex Review at vii.
235 Polar Vortex Review at 2,4.
236 NERC 2015 Winter Review, December 2015, at iv. https://www.nerc.com/pa/rrm/ea/ColdWeatherTrainingMaterials/2015_Winter_Review_December_2015_FINAL.pdf
237 *See* Table 2, in 2015 NERC report. Southern Company and TVA still did not break their 2014 winter peak load records.
238 NERC 2015 Winter Review, December 2015, at iv.
239 NERC 2015 Winter Review, at iv.
240 *See* note 44.
241 NERC 2015 Winter Review, at 1.

NERC provided examples of preparations taken by the generating unit owners, including:

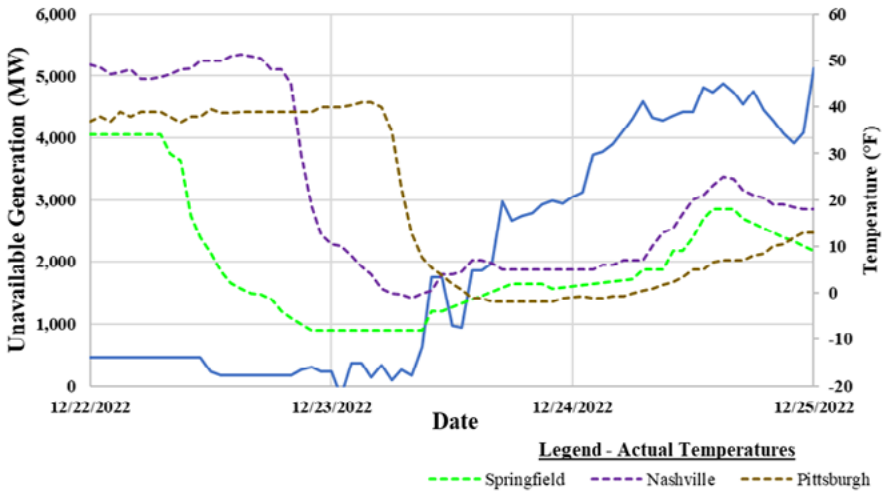
- Owners started units earlier than expected, due to anticipated colder temperatures, helping to mitigate the risk of taking more time to start.
  - Keeping stations in service overnight with a reduced output level was beneficial to ensuring that the unit would stay warm and online when needed for the peak.
- Proactive staffing of typically unmanned stations enabled more rapid response.
- Many generating units in the PJM footprint participated in prewinter operational testing, and those that did, had a lower rate of forced outages than those that did not.

But seven years later, faced with peak loads that were generally lower than in 2014 or 2015, many of the same BAs experienced high rates of forced outages. PJM, for example, found that despite many measures undertaken in the wake of the Polar Vortex, its Capacity Resource forced outage rate was worse in the Event than in the Polar Vortex (24 percent versus 22 percent).

4. BLACKSTART UNITS

Of significant concern is that blackstart-designated generating units totaling 19,000 MW experienced forced outages, derates or failures to start during the Event. Blackstart-designated units are those that claim the ability to be started without the aid of external power sources. Given this unique functionality, blackstart units serve a critical grid reliability function—restarting the grid in the event of its failure. It is, therefore, disconcerting that generation loss due to the unavailability of blackstart-designated units coincided with the arrival of extreme cold weather conditions and the corresponding acceleration of generation loss throughout the bulk electric system.

Figure 81: Unavailable Generation - Blackstart-Capable Generating Units, December 22 - 24, 2022



242 NERC 2015 Winter Review at 6.

Figure 82: Unavailable Generation in the Event Area, Blackstart-Capable Generating Units, By Primary Cause

Blackstart Units – Reported Event Cause	Event Count	Unavailable MW
Mechanical/Electrical Issues	89	7,737
Fuel Issues	86	6,717
Freezing Issues	61	3,565
Environmental/ Safety Issues	6	810
Transmission System Issues	6	261

Figure 83: Unavailable Generation in the Event Area, Blackstart-Capable Generating Units, By Primary Cause and Dual Fuel Capability

Blackstart Units Type	Freezing Issues (MW)	Fuel Issues (MW)	Mechanical/Electrical Issues (MW)	Other (MW)
Gas Only	1,266	5,060	1,200	0
Gas/Oil	1,678	920	3,607	561
Other	621	737	2,910	510
Total	3,565	6,717	7,737	1,071

Altogether, 155 blackstart-designated generating units (119 of which were natural gas-fired) reported more than 248 discrete outages, derates or failures to start. Of these, 29 percent reported *multiple* outages, and 23 percent were start-up failures—*i.e.* units that failed to perform the essential function of blackstart units.

Blackstart generation loss unit types included natural gas-fired, dual-fuel capable, and other primary fuel types.

5. HIGH WIND SHUTOFFS

Most conventional wind turbines are designed to operate at wind speeds of no more than 55 mph and must shut down when wind speed exceeds those levels.[243] Excluded from the foregoing analysis of Freezing Issues and Mechanical/Electrical Issues were wind turbine units that reported generation loss due to high winds—High Wind Shutdown—as the cause of their forced outage. Some generating units reported unique outages lasting only a handful of minutes on a turbine-by-turbine basis, resulting in hundreds of spreadsheet lines—but ultimately these shutoffs did not constitute a significant source of generation loss during Winter Storm Elliott. In aggregate, Generation Owners attributed fewer than 1,000 MW of generation loss to High Wind Shutdowns.

6. FUEL ISSUES

Fuel Issues accounted for 24 percent of all generation lost during the Event—a cumulative total of more than 86,000 MW—and were the third largest cause of unplanned

243 *See*, Office of Energy Efficiency & Renewable Energy, *How Do Wind Turbines Survive Severe Storms?* (June 20, 2017), https://www.energy.gov/eere/articles/how-do-wind-turbines-survive-severe-storms ("When the anemometer registers wind speeds higher than 55 mph (cut-out speed varies by turbine), it triggers the wind turbine to automatically shut off.").

outages, derates and failures to start. In total, 452 generating units reported 730 distinct forced outages, derates or failures to start during the Event due to Fuel Issues. Natural gas-fired generating units experienced the overwhelming majority of Fuel Issues: 71,423 MW of natural gas-fired generating unit outages and derates were 83 percent of all Fuel Issue-caused generation outages and derates during the Event, as shown in Figure 84, below.[244] For natural gas-fired generation alone, comparing the outages during the Event caused by Natural Gas Fuel Issues to Freezing Issues and Mechanical/Electrical Issues, Natural Gas Fuel Issues caused nearly one-third (31 percent, by MW) of natural gas-fired generating units' unplanned outages and derates.[245]

Figure 84: Unplanned Unavailable Generation in the Event Area Caused by Fuel Issues, December 21-26, 2022

Generating Unit Primary Fuel Type	Unplanned Outages During Event (MW)	Percent of Unplanned MW Outages Due to Fuel Issues
Gas	71,423	83%
Coal	13,439	16%
Other	1,602	2%

Fuel-Issue-caused natural gas-fired generation outages (referred to as the sub-cause "Natural Gas Fuel Issues" described earlier in the Report) include the combined effects of decreased natural gas production; cold weather impacts and mechanical problems at production, gathering, processing and pipeline facilities resulting in gas quality issues and low pipeline pressure; supply and transportation interruptions; curtailments and failure to comply with contractual obligations. Additionally, it includes shippers' inability to procure natural gas due to tight supply, prohibitive, scarcity-induced market prices, or mismatches between the timing of the natural gas and energy markets.

See Figure 85, below, for information on the contractual arrangements held by some of the GOs/GOPs involved in the Event.

Each subset of the 71,423 MW of natural gas-fired generating unit outages and derates due to Natural Gas Fuel Issues total tells a distinct story:

- Nearly 7,500 MW of generation outages were linked to gas delivery pressure issues, reflecting the difficulty natural gas pipelines and other distribution points faced in responding to production losses. Another 2,000 MW was linked to transportation constraints.
- Market Issues and Market Price Restrictions accounted for approximately 24,000 MW of generation loss—reinforcing how surging demand and production losses impacted generating units. Somewhat paradoxically, GOs/GOPs of natural gas-fired generating units attributed more generation loss to the failure of gas suppliers to satisfy firm supply commitment and/or pipeline firm curtailments (16,500 MW of cumulative generation loss) than to interruptible pipeline interruptions

244 This is in part because natural gas-fired generating units were the most common (over 41 percent of the generation capacity in the Event Area, as seen in Figure 11). Natural gas-fired units were also the most common in prior extreme cold weather events (2011: ERCOT – 52 percent; 2021: ERCOT – 52 percent, MISO South – 60.6 percent, SPP – 38.5 percent). The only other units that experienced material generation loss due to Fuel Issues during Winter Storm Elliott were coal units. Fuel Issues for all fuels other than gas and coal, combined, accounted for two percent of all unplanned outages, derates and failures to start.

245 *See* Appendix C.3. Causes of Unplanned Generation Outages, by Fuel Type of Generation.

(14,000 MW of cumulative generation loss). This finding was supported by the Team's cross-check of the causes claimed against data provided by the GOs/GOPs of those generating units about their contractual arrangements.

Figure 85: Generating Unit Natural Gas Commodity and Transportation Contracts

Generating Unit Natural Gas Commodity and Transportation Contracts										
Type of Gas Commodity and Transportation Contract:	MISO		PJM		Southern		SPP		Other BAs	
	Generators	Percent	Generators	Percent	Generators	Percent	Generators	Percent	Generators	Percent
Firm Commodity/Firm Transportation	53	38%	61	37%	0	0%	0	0%	28	26%
Firm Commodity/Mixed Transportation	0	0%	1	1%	0	0%	0	0%	0	0%
Firm Commodity/Non-Firm Transportation	8	6%	26	16%	0	0%	0	0%	0	0%
Non-Firm Commodity/Non-Firm Transportation	28	20%	18	11%	2	5%	27	34%	9	8%
Non-Firm Commodity/Mixed Transportation	3	2%	0	0%	0	0%	15	19%	2	2%
Non-Firm Commodity/Firm Transportation	20	14%	11	7%	0	0%	17	21%	0	0%
Mixed Commodity/Mixed Transportation	11	8%	21	13%	0	0%	16	20%	20	19%
Mixed Commodity/Firm Transportation	7	5%	3	2%	14	38%	0	0%	14	13%
Mixed Commodity/Non-Firm Transportation	8	6%	17	10%	21	57%	3	4%	28	26%
Did not provide information re: commodity contract type	1	1%	2	1%	0	0%	2	3%	0	0%
No contract or did not provide information about transportation contract type	2	1%	7	4%	0	0%	0	0%	5	5%
Total	**141**	**100%**	**167**	**100%**	**37**	**100%**	**80**	**100%**	**106**	**100%**

During the Event, unplanned natural production outages due to freeze-related issues, road conditions, loss of power and unplanned outages of gathering and processing facilities decreased the natural gas available for supply and transportation to many natural gas-fired generating units in the Eastern Interconnection. Out of the **61** power plants[246] that reported having at least 75 percent of their fuel requirement under firm transportation, only **25** reported also having at least 75 percent of the fuel needed for their winter

246 The Team had a sample size of slightly over 200 generating plants that provided most of the requested information about fuel contracting practices. Generator owners provided fuel contract data on a plant basis, which often included multiple generating units. The Team removed plants that did not answer the requests for their total or daily gas natural gas requirements, resulting in a list of 155 plants.

peak operation under firm supply contracts. The Team focused on GOs/GOPs that provided their fuel requirements. As shown in the figure, the plants were nearly evenly split between those that had no firm transportation at all, and those that had over 75 percent of their natural gas fuel requirements supported by firm transportation.

Figure 86: Number of Power Plants by the Level of Firm Transportation Service Contracts Covering Their Natural Gas Fuel Requirements

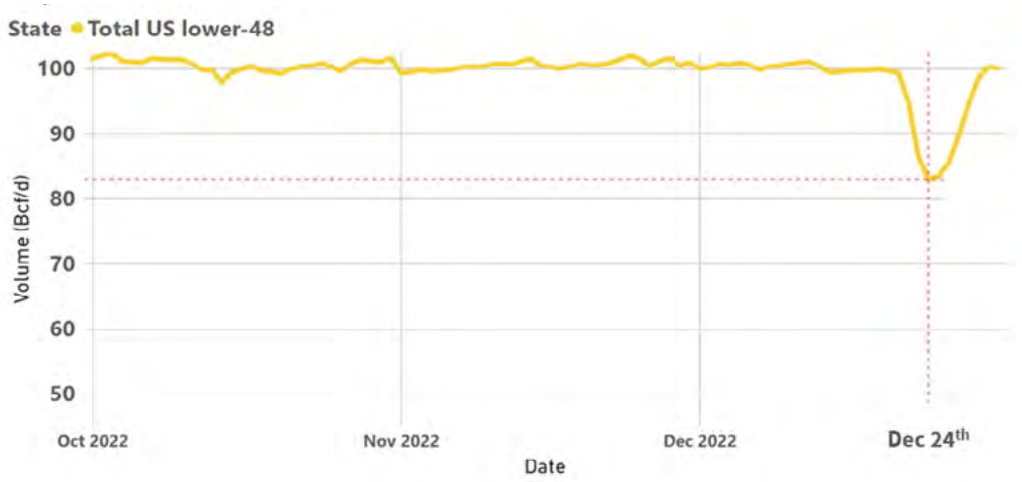


C. Causes of Natural Gas Supply and Delivery Facility Outages[247]

1. SUMMARY

As Winter Storm Elliott moved across North America and temperatures dropped, natural gas production in the lower 48 states declined, with volumes on December 22 decreasing 4,411 MMcf/day from the previous day. The largest daily decline in natural gas production – 8,368 MMcf/day – occurred between December 22 and December 23. Dry natural gas production for the lower 48 U.S. saw an 18 percent decline, falling to a low of 82.9 Bcf/day on December 24, 2023, as shown in Figure 87, below.

Figure 87: Daily Dry Natural Gas Production (November - December 2022)[248]



Winter Storm Elliott primarily affected the Marcellus and Utica Shale formations. Marcellus Shale production volumes reached a low of 21,856 MMcf/d on December 24 (23 percent decrease compared to maximum production on December 19). Utica Shale production volumes reached a low of 3,017 MMcf/d on December 26 (54 percent decrease compared to maximum production on December 19). Focusing on states, the largest natural gas production decreases in the Event Area occurred in Pennsylvania, Ohio, and West Virginia, whereas Louisiana production was relatively unaffected. Ohio saw the largest relative decline compared to maximum production volumes for December, reaching a low of 3,018 MMcf/d on December 26 (54 percent decline compared to production on December 17). Pennsylvania and West Virginia both reached their lowest production volumes of 16,226 MMcf/d (22 percent decline compared to production on December 20) and 5,630 MMcf/d (26 percent decline compared to production on December 18), respectively, two days prior on December 24. Figures 88 and 89[249] show the declines by state over time, and the geographic locations of the volumetric outages, respectively.

247 Unless otherwise stated, the source of data for this section is the sample of producers, gatherers, processors, and pipelines that responded to the Team's data requests.

248 Source: S&P Global Commodity Insights, ©2023 by S&P Global Inc.

249 Source for both figures: S&P Global Commodity Insights, ©2023 by S&P Global Inc.

Figure 88: Sum of Natural Gas Production Volume, by Date and State (October - December 2022)

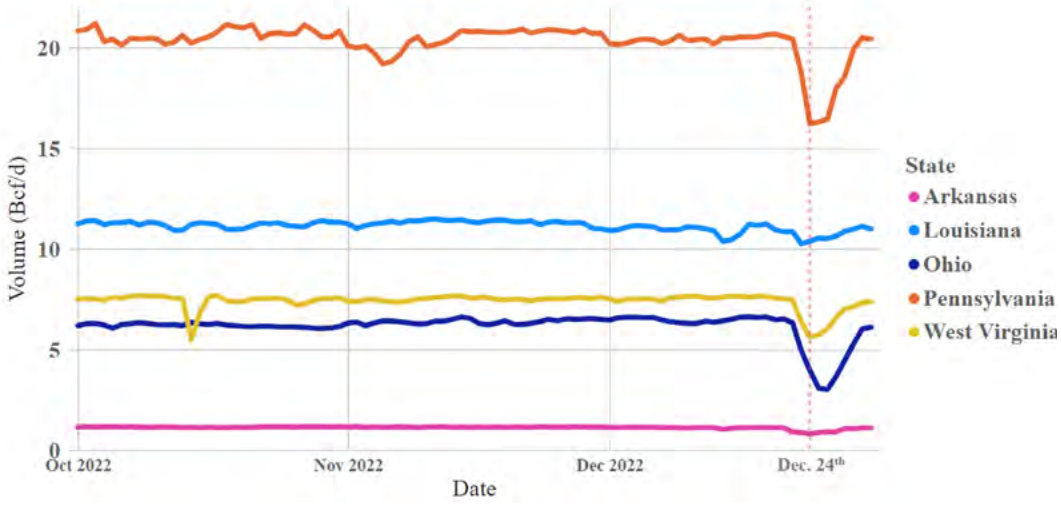
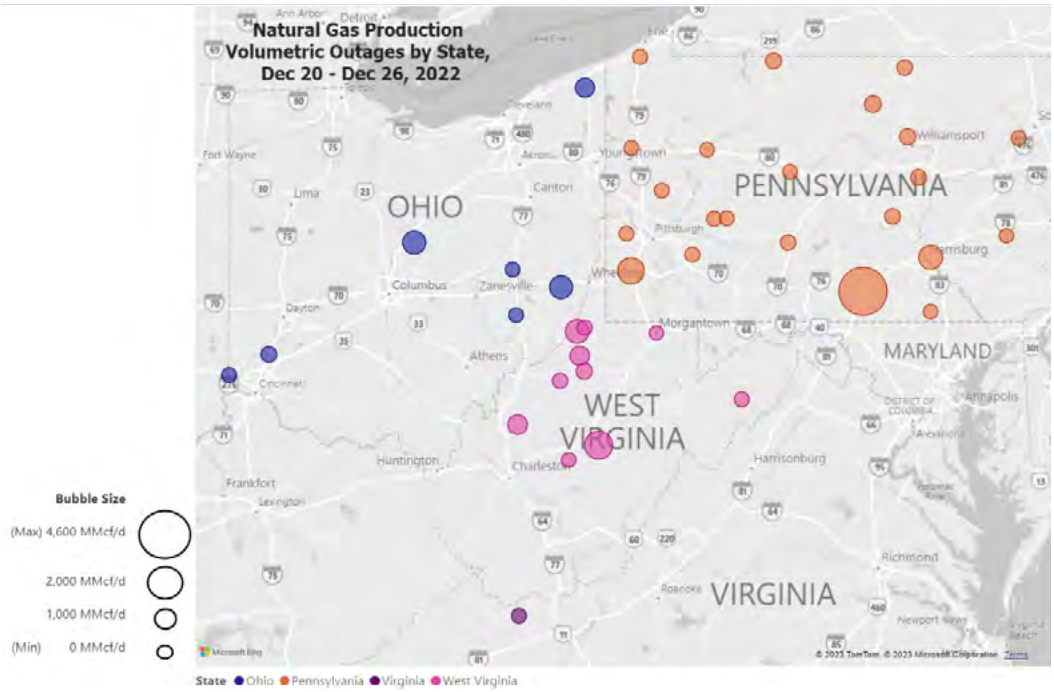


Figure 89: Natural Gas Production Volumetric Outages by State, December 20 – 26, 2022



Certain pipeline injection points were especially affected. Westmoreland, Pennsylvania, declined by over 6.8 Bcf over the Gas Days of December 21-26, compared to expected production, and Greene, Pennsylvania, declined by over 3 Bcf. Other points experiencing declines over one Bcf included Calhoun and St. Clair Pennsylvania, Monroe, Ohio and Marshall, West Virginia.[250]

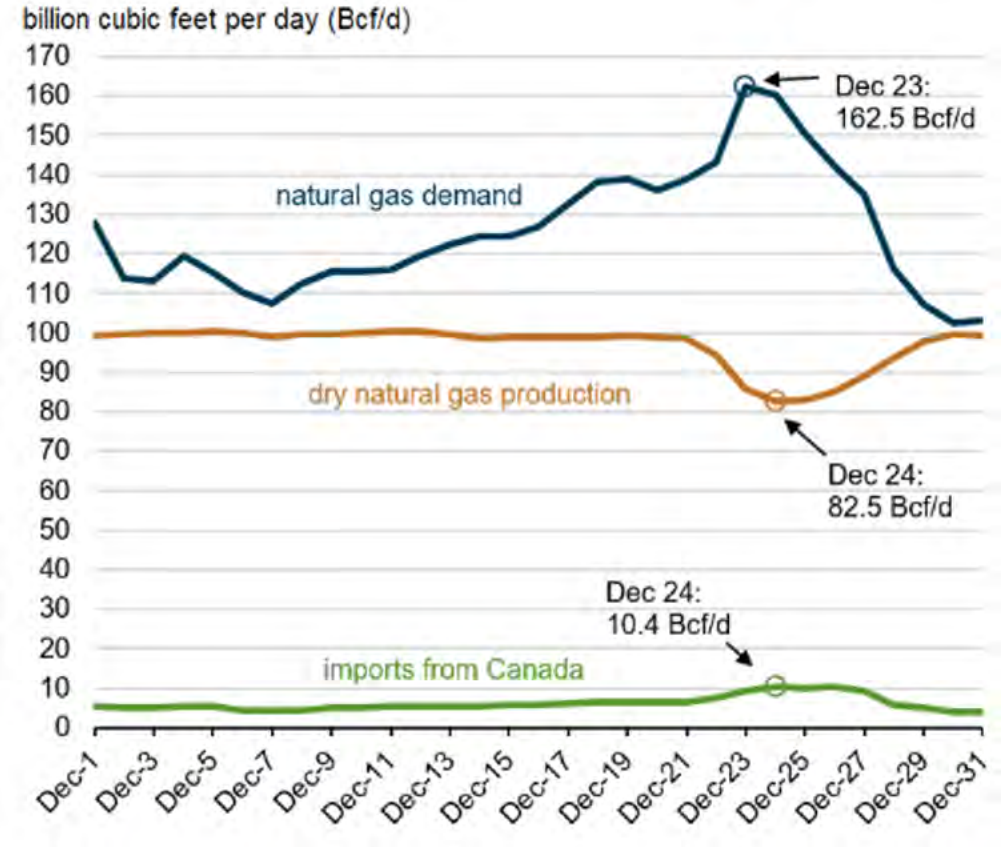
The last time U.S. natural gas production rapidly declined to this degree was during Winter Storm Uri.

250 *See* Figure 50 for a map of receipt points experiencing supply shortages.

Record natural gas demand during Winter Storm Elliott was met by increasing withdrawals from storage and pipeline imports from Canada. Natural gas pipeline imports from Canada supplied 10.4 Bcf of natural gas to the United States on December 24, the highest daily natural gas imports from Canada since February 2007.[251]

Figure 90 below shows record peak demand for natural gas on December 23 and the production nadir on December 24.

Figure 90: Daily Natural Gas Supply and Demand in the Lower 48 States, December 1 – 31, 2022[252]



It is important to note that natural gas demand, as that term is used by the U. S. Energy Information Administration, is the sum of actual gas consumption, natural gas and LNG exports, pipeline losses and fuel gas. EIA's natural gas demand does not include the gas that would have been burned by dispatched natural gas-fired generating units rendered unavailable due to Natural Gas Fuel Issues, Freezing Issues, or other causes. Put another way, although EIA reported record demand for December 23, that figure under-represented the potential natural gas demand because it excluded natural gas that generators would have consumed had they not experienced an outage, derate, or failure to start.

The December 23 demand for gas of 162.5 Bcf included estimated total consumption of natural gas in the lower 48 states of 141 Bcf – a record daily high (exceeding the previous record daily high of 137.4 Bcf set on January

251 Natural Gas Weekly Update, January 19, 2023 – U.S. Energy Information Administration, (last visited November 3, 2023).

252 Source: S&P Global Commodity Insights, ©2023 by S&P Global Inc.

1, 2018) and 21.5 Bcf of exported gas, pipeline losses, and fuel gas. Figure 91, below, shows the relative shares of natural gas consumption for natural gas fired-generating units ("PowerBurn"), industrial production, residential and commercial use ("ResComm"), and LNG feedgas for the Event Area. Power burn and residential and commercial use consumed similar shares until the onset of the extreme cold weather, when residential and consumer usage spiked. LNG feedgas decreased by nearly 20 percent, mostly in the Southeast as shown in Figure 92, below. Figure 92 shows the overall and relative increase (or decrease) in the various sectors' natural gas consumption for the Northeast, Midwest and Southeast regions, combined. Residential and commercial use had the largest percentage increase by far, at nearly 50 percent, with pipe losses coming in second, increasing by a third.

Figure 91: Northeast/Midwest/Southeast Natural Gas Consumption[253]

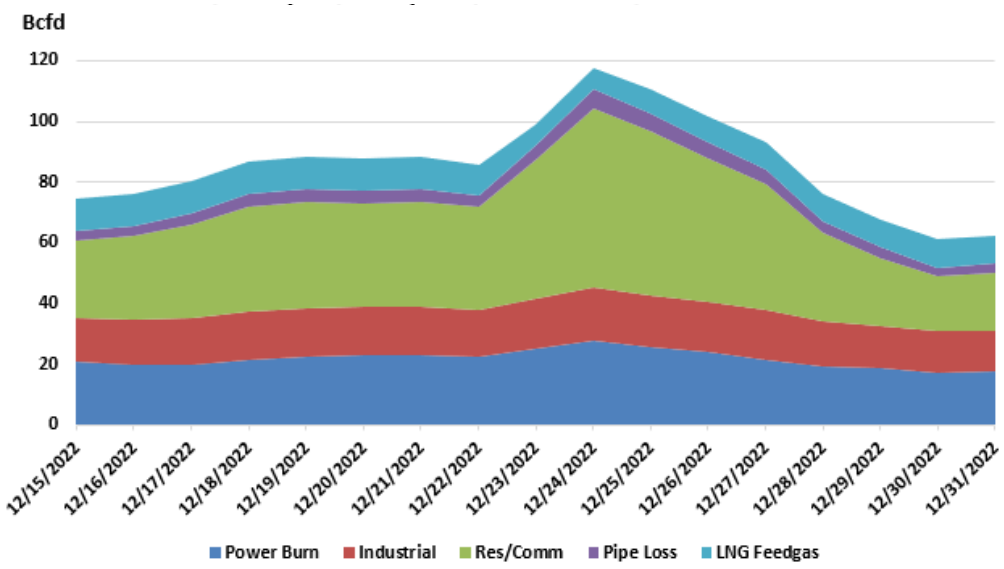


Figure 92: Overall and Relative Increase in Natural Gas Consumption for the Northeast, Midwest and Southeast Regions[254]

Bcfd	December 15-20 Average	December 21-26 Average	Percent Change
Northeast/Midwest/Southeast Natural Gas Demand	82.3	100.5	22.1%
Power Burn	21.2	24.6	15.8%
Res/Comm	31.4	46.0	46.5%
Industrial	15.3	16.5	7.9%
LNG Feedgas	10.6	8.5	-19.8%
Pipe Loss	3.9	5.0	29.2%

253 Source: S&P Global Commodity Insights, ©2023 by S&P Global Inc.

254 Source: S&P Global Commodity Insights, ©2023 by S&P Global Inc.

2. NATURAL GAS PRODUCTION DECLINES

The Team sought to gather information from the largest producers in the area that experienced the greatest decreases in natural gas production. Based on the Team's analysis of publicly-available information and data from S&P Global Community Insights, the Team focused its data collection efforts on a sample of 12 large producers in Pennsylvania, Ohio and West Virginia. Eight producers with operations in Pennsylvania, Ohio, West Virginia, and Virginia – representing over 15,000 natural gas wells – provided responses to questions about estimated marketed production declines during Winter Storm Elliott.[255] Producers were asked to identify production volume declines by date and county, and to identify an associated cause for the declines. Only 38 to 53 percent of the production entities provided the requested data for December 23 to 26,[256] the days with the most substantial production losses, as shown in Figure 93, below. One producer did not provide any information after several attempts by the Team.[257] The Team grouped them into the following categories: Freeze-offs; Downstream Issues; Access to roads cut-off; Proactive Reduction in Sales.[258]

Figure 93: Natural Gas Marketed Production Volume Declines, December 20 – 26, 2022

Date	Marketed Production Volume Decline MMcf/d with Causes	Total Marketed Production Volume Decline (MMcf/d)	% of Data
12/20/2022	541.24	718.82	75%
12/21/2022	569.87	838.19	68%
12/22/2022	532.48	854.27	62%
12/23/2022	2,044.46	3,869.75	53%
12/24/2022	1,579.86	4,209.68	38%
12/25/2022	1,878.98	4,416.39	43%
12/26/2022	1,743.17	3,832.59	45%

All but one producer identified freeze-offs as a primary cause of production reductions, including frozen production equipment as well as wellhead freeze offs. Seven of the 10 producers identified downstream issues

255 In total, 10 producers responded to the data request, but only eight provided the data on the estimated marketed production declines. *See* footnote 100 which describes the relevant regions the entities were asked to provide production data.

256 This is an example of an issue the Team faced when gathering information from non-jurisdictional entities.

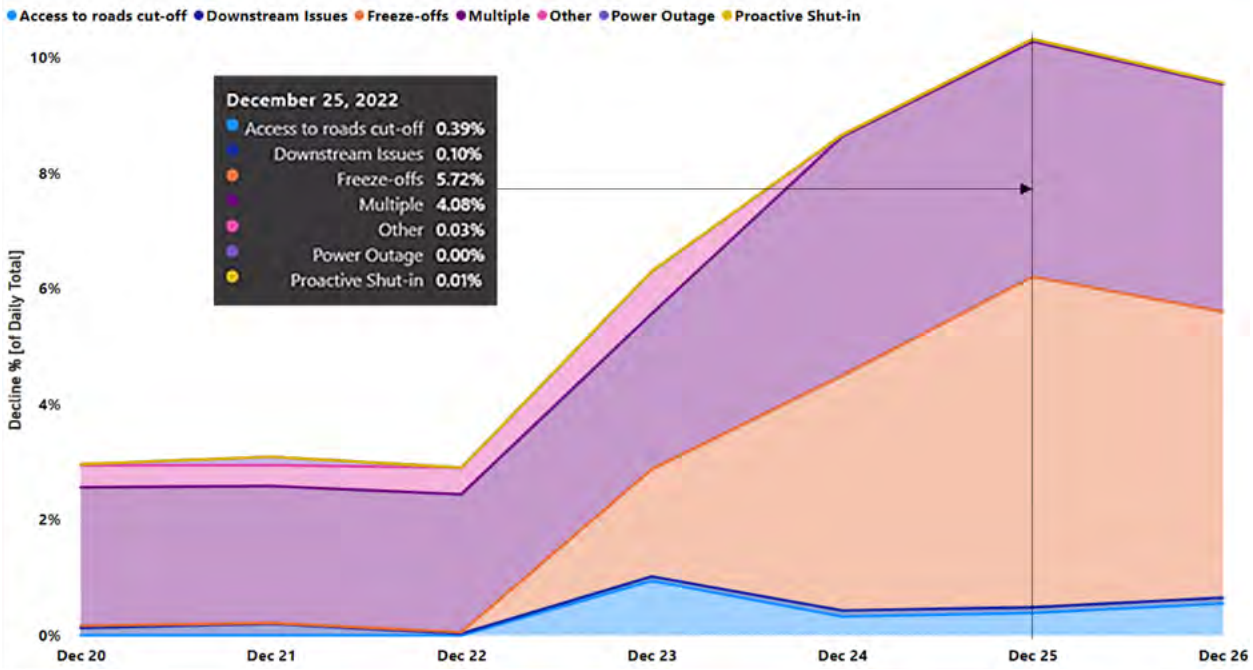
257 Details regarding the way in which this producer responded illustrate the benefits that will obtain if an agency or entity is given jurisdiction over the reliability of the natural gas system. The Team initially tried to contact the producer via written data requests. When the producer did not respond, the Team assumed that the data requests had not been received or had reached the wrong person – issues that had arisen with other producers and that could be resolved via a phone call. The Team contacted the producer and was referred to a specific individual. He, however, did not return calls. The Team finally managed to reach him in his office, and he said that it was his understanding that cooperation with the Team was "voluntary." Although the Team explained the importance of cooperation in helping to tell the entire story of what happened during Winter Storm Elliott, he said only that he would discuss it with others at the producer and would call back in a week or two. The Team never heard from him again.

258 The Team had to group the causes provided into overarching categories since there was a significant variation in the causes used/provided in the responses. This is also another reason why an agency or entity with jurisdiction over the reliability of the natural gas system could prove beneficial by creating some level of standardization or uniformity in outage/operational impacts cause designations that could support meaningful analysis (compare, e.g., GADS data specifications for BES GOs/GOPs to provide data about generating unit outages Generating Availability Data System (GADS) (nerc.com)).

as a significant driver of production declines; these issues included outages in gathering systems, compressors, and processing plants, as well as pipelines that could not take the gas from the producers,[259] which caused idling of producer equipment, which itself exacerbated production equipment freezing and caused further reductions in natural gas production. Five out of 10 identified poor road conditions, which prevented personnel and, in some cases, water hauling trucks, from reaching remote sites, although this was not as common as during Winter Storm Uri. Finally, two producers proactively reduced the volume of contractual sales during the Event because they expected production declines.

Figure 94, below, illustrates the decline by category calculated against the daily estimated production as reported by producers. Figure 95 breaks down the causes of production losses on December 23 to 26. Freeze-offs peaked as the leading cause of production declines on December 24 and 25, while downstream issues peaked on December 23.

Figure 94: Natural Gas Daily Production Decline by Cause, December 20 – 26, 2022



259 One pipeline stated that leading up to and on the evening of December 23, they started to pack their lines in preparation for high demand on December 24. The high pressure temporarily prevented producers from being able to move their gas onto the pipeline. The same pipeline also had a lag in demand load on the morning of December 24, causing pressures to remain high, which exposed producers to further freezing vulnerabilities as they could not move their supply onto the pipeline system at that time.

Figure 95: Total Percentages of Natural Gas Daily Production Decline by Cause, December 23 – 26, 2022

	Production Event Causes on December 23rd	
	Natural Gas Infrastructure Condition	Facility Event Causes
Freeze-offs	Equipment freezing at well/gathering facilities.	16.6%
Downstream Issues	Third party/downstream issues (e.g., processing plant down)	44.5%
Access to roads cut-off	Road/access to well/gathering facilities	8.4%
Multiple	Multiple issues (combination of two or more of above issues)	24.0%
Other Issues, Unrelated Issues	Proactive shut-in	0.0%
	Other Issues	6.5%
Total		100.0%

	Production Event Causes on December 24th	
	Natural Gas Infrastructure Condition	Facility Event Causes
Freeze-offs	Equipment freezing at well/gathering facilities.	46.9%
Downstream Issues	Third party/downstream issues (e.g., processing plant down)	1.2%
Access to roads cut-off	Road/access to well/gathering facilities	3.8%
Multiple	Multiple issues (combination of two or more of above issues)	47.8%
Other Issues, Unrelated Issues	Proactive shut-in	0.0%
	Other Issues	0.3%
Total		100.0%

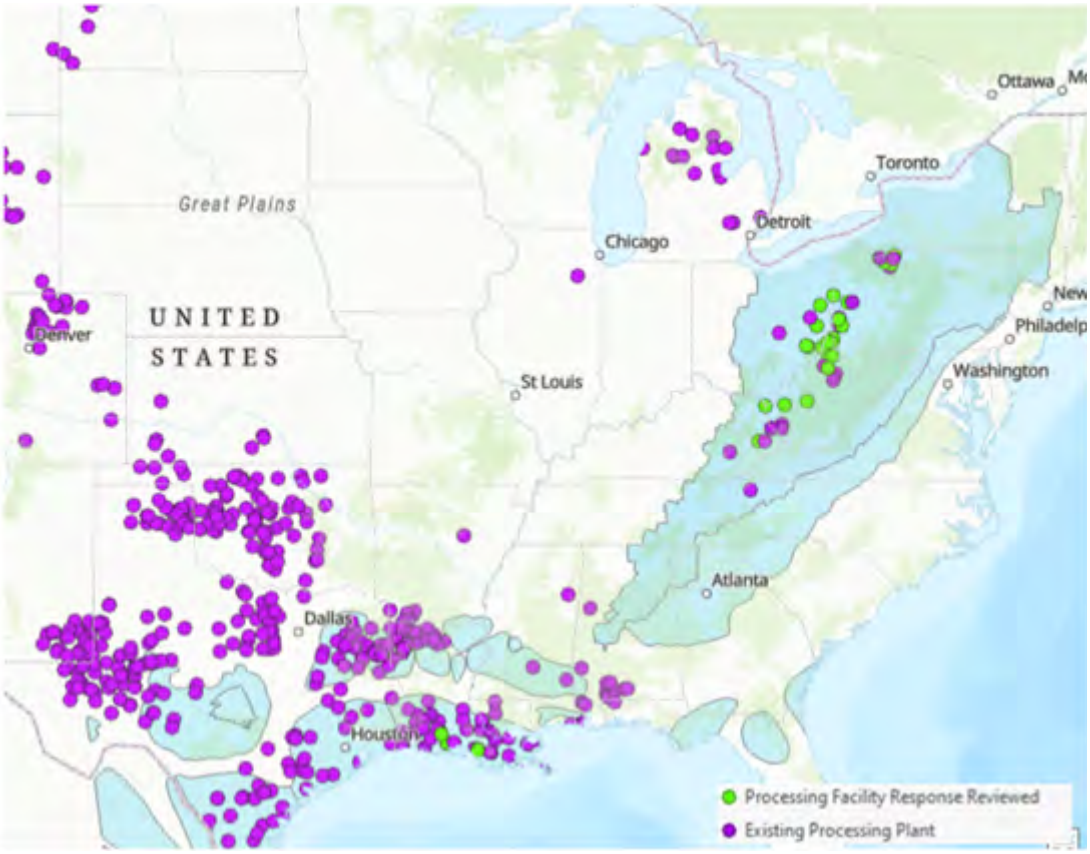
	Production Event Causes on December 25th	
	Natural Gas Infrastructure Condition	Facility Event Causes
Freeze-offs	Equipment freezing at well/gathering facilities.	55.4%
Downstream Issues	Third party/downstream issues (e.g., processing plant down)	1.0%
Access to roads cut-off	Road/access to well/gathering facilities	3.7%
Multiple	Multiple issues (combination of two or more of above issues)	39.5%
Other Issues, Unrelated Issues	Proactive shut-in	0.1%
	Other Issues	0.3%
Total		100.0%

	Production Event Causes on December 26th	
	Natural Gas Infrastructure Condition	Facility Event Causes
Freeze-offs	Equipment freezing at well/gathering facilities.	51.8%
Downstream Issues	Third party/downstream issues (e.g., processing plant down)	1.0%
Access to roads cut-off	Road/access to well/gathering facilities	5.7%
Multiple	Multiple issues (combination of two or more of above issues)	41.1%
Other Issues, Unrelated Issues	Proactive shut-in	0.1%
	Other Issues	0.3%
Total		100.0%

3. NATURAL GAS PROCESSING

The Team obtained data from a total sample size of 26 natural gas processing plants located in the Texas-Louisiana-Mississippi Salt Basin (8) and Appalachian Basin (18). However, the Report focuses on the Appalachian Basin because it experienced the largest decrease in natural gas supply during the Event. Data regarding the Texas-Louisiana-Mississippi Salt Basin is in Appendix D. See Figure 96, below for depiction of geographic locations of the processing facilities.

Figure 96: Natural Gas Processing Facilities in Event Area



As shown in Figure 97 below, temperatures declined drastically on December 23. Weather stations in Morgantown, West Virginia, which is located within the Appalachian Basin, captured temperatures ranging from 46 degrees to -2 degrees on December 23. This decline continued December 24, over the course of which the average temperature in Morgantown was 29 degrees below the historical normal.[260]

Figure 97: Morgantown, WV Actual Daily Temperatures

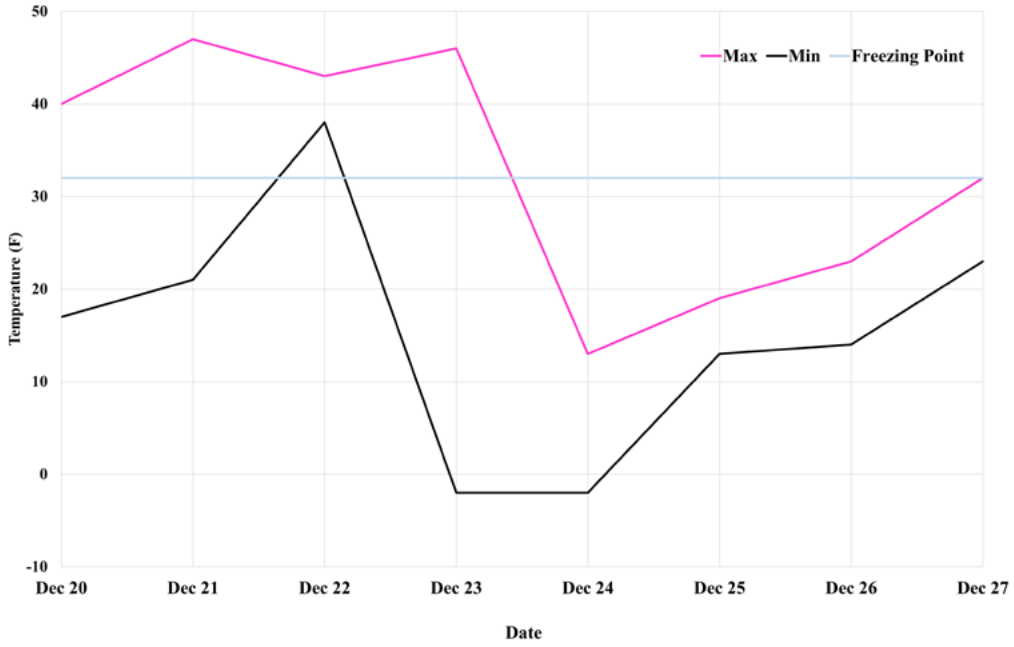
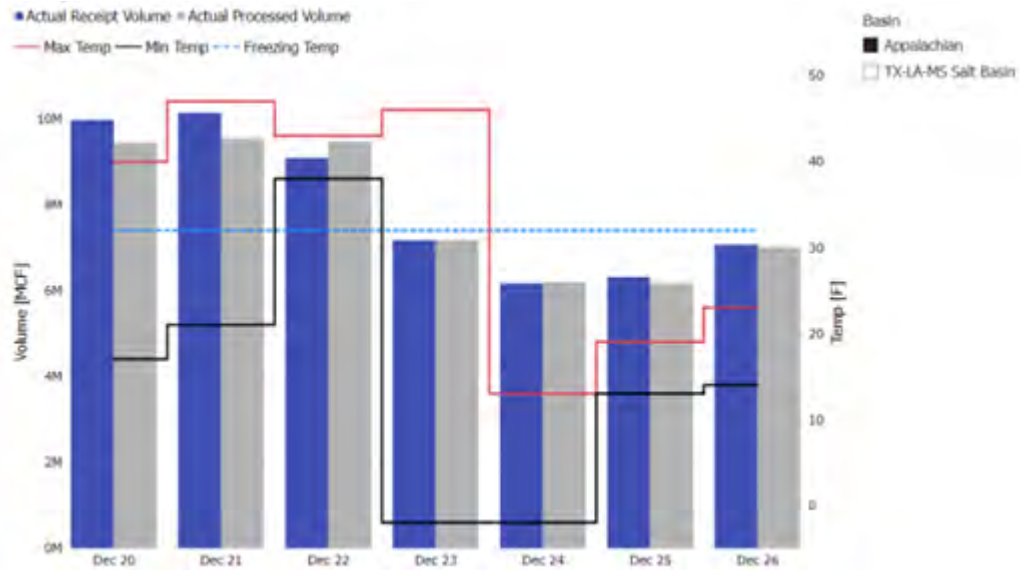


Figure 98: Appalachian Basin Processing Facility Receipt Volume and Processed Volume, December 20 – 26, 2022



260 *See* Figure 25 for departures from normal lows for December 25.

As temperatures plunged, natural gas demand increased, while at the same time, the volume of gas received by processing facilities declined, as seen in Figure 98, above.

Some processing facilities that participated in the inquiry reported they did not receive the full contracted amount of gas supply from producers. Despite not receiving all the gas they expected, processing facilities reported that they processed all the gas they received on the days that receipt volume was most decreased.

Processing losses, analyzed by the day of maximum losses in each basin, were largely caused by reduced gas supply, which in turn was caused by producers' equipment freezing or pressure issues in their gathering pipeline systems. However, as shown in Figure 99 below, as it became colder, some processing facilities also experienced mechanical outages/failures, power outages, and plant equipment Freezing Issues. Overall, the top causes in both basins are, in order, reduction in receipt volumes, producer freeze/pressure issues (these would also cause a reduction in receipt volumes but some producers expressly identified these causes), power outages, and processing facility mechanical outages. As shown in Figure 100, on the December 23 (the second) table, reduced natural gas receipts were by far the largest cause of lost processing facility volume, accounting for 71 to 84 percent of those losses. Processing facility Freezing Issues caused 10 to 16 percent of the lost processing volume, and curtailment or loss of power supply, which had been a substantial cause in the 2021 Event, maxed out at 5.6 percent. Only 25 percent of the 26 processing plants were protected from power outages by local power provider critical load designation agreements.

Figure 99: Appalachian Basin Event Processing Facility Event Causes—Dec. 22 – 29, 2022

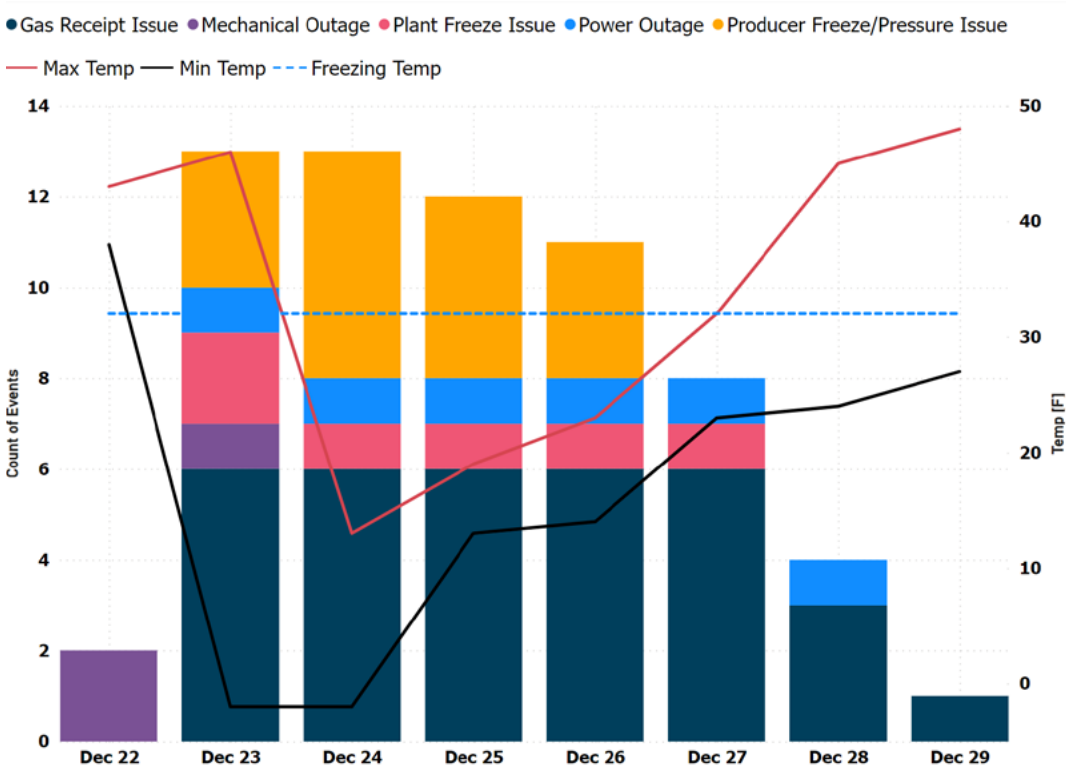


Figure 100: Processing Facilities Event Causes, December 22 – 26, 2022

Processing Facility Disruption Event Causes on December 22		
Cause	**Natural Gas Infrastructure Conditon**	**Facility Event Causes**
Freezing Temperature and Weather Conditions	Reduced Natural Gas Receipt from Production/Gathering/Facilities	71.4%
	Freezing Issues at Processing Facilities	0%
Loss of Power	Processing Facilties- Loss of Power Supply or curtailmennt	0%
Other issues	Mechanical Outage - Non weather Related	28.6%
Total		100%
* There were a total of 7 causes of processing plant events occuring on December 22		

Processing Facility Disruption Event Causes on December 23		
Cause	**Natural Gas Infrastructure Conditon**	**Facility Event Causes**
Freezing Temperature and Weather Conditions	Reduced Natural Gas Receipt from Production/Gathering/Facilities	72.2%
	Freezing Issues at Processing Facilities	16.6%
Loss of Power	Processing Facilties- Loss of Power Supply or curtailmennt	5.6%
Other issues	Mechanical Outage - Non weather Related	5.6%
Total		100%
* There were a total of 18 causes of processing plant events occuring on December 23		

Processing Facility Disruption Event Causes on December 24		
Cause	**Natural Gas Infrastructure Conditon**	**Facility Event Causes**
Freezing Temperature and Weather Conditions	Reduced Natural Gas Receipt from Production/Gathering/Facilities	81.82%
	Freezing Issues at Processing Facilities	13.60%
Loss of Power	Processing Facilties- Loss of Power Supply or curtailmennt	4.500%
Other issues	Mechanical Outage - Non weather Related	0%
Total		100%
* There were a total of 22 causes of processing plant events occuring on December 24		

Processing Facility Disruption Event Causes on December 25		
Cause	**Natural Gas Infrastructure Conditon**	**Facility Event Causes**
Freezing Temperature and Weather Conditions	Reduced Natural Gas Receipt from Production/Gathering/Facilities	84.2%
	Freezing Issues at Processing Facilities	10.5%
Loss of Power	Processing Facilties- Loss of Power Supply or curtailmennt	5.3%
Other issues	Mechanical Outage - Non weather Related	0%
Total		100%
* There were a total of 19 causes of processing plant events occuring on December 25		

Processing Facility Disruption Event Causes on December 26		
Cause	**Natural Gas Infrastructure Conditon**	**Facility Event Causes**
Freezing Temperature and Weather Conditions	Reduced Natural Gas Receipt from Production/Gathering/Facilities	83.3%
	Freezing Issues at Processing Facilities	11.1%
Loss of Power	Processing Facilties- Loss of Power Supply or curtailmennt	5.6%
Other issues	Mechanical Outage - Non weather Related	0%
Total		100%
* There were a total of 18 causes of processing plant events occuring on December 26		

4. NATURAL GAS DELIVERY

The interstate natural gas pipeline facilities experienced 19 equipment issues which directly affected shippers, including Generation Owners and LDCs. The largest reported cause of equipment issues was weather/ freezing issues, followed by mechanical issues (see Figure 101, below). The cold temperatures caused valves and compressor units at varying locations along the pipeline system to freeze, reducing or preventing the flow of gas through the facilities (see Figure 102, below). Eight force majeures, five of which were due to freezing, affected a total of 156 firm customers.[261] Yet a sampling of the force majeure provisions of interstate natural gas pipeline tariffs indicates that they either expressly included language that used "freezing of pipelines [or pipes or lines]" as examples of force majeure, even though pipeline owners can take measures to avoid

261 *See* Section III.B.4(a)(3).

freezing of pipeline equipment; or they included broad language about "unscheduled repairs" or "mechanical or physical failure that affects the ability to transport gas," which could be interpreted to include freezing-related issues."[262] Similarly, the force majeure clause in the NAESB "Base Contract for Sale and Purchase of Natural Gas" expressly includes "weather related events affecting an entire geographic region, such as low temperatures which cause freezing or failure of wells or lines of pipe." Using express inclusions or broad language in force majeure clauses disincentivizes natural gas infrastructure entities from taking steps to ensure that natural gas will be available when it is most needed, during an extreme cold weather event.

Figure 101: Pipeline-Reported Equipment Issues Directly Affecting Shippers – Cause Breakdown

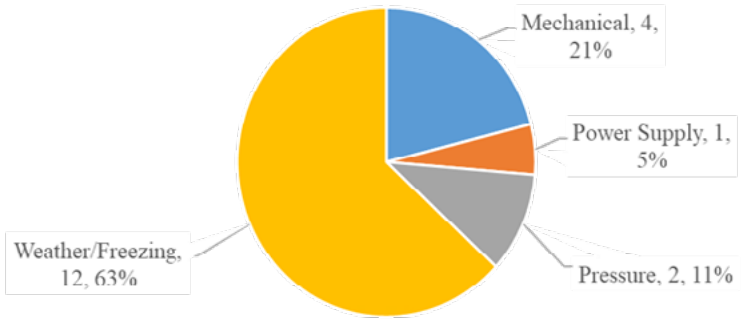
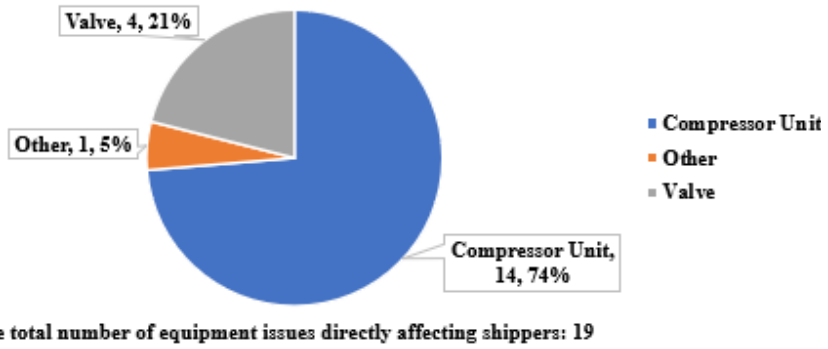


Figure 102: Pipeline-Reported Equipment Issues Directly Affecting Shippers by Equipment Type



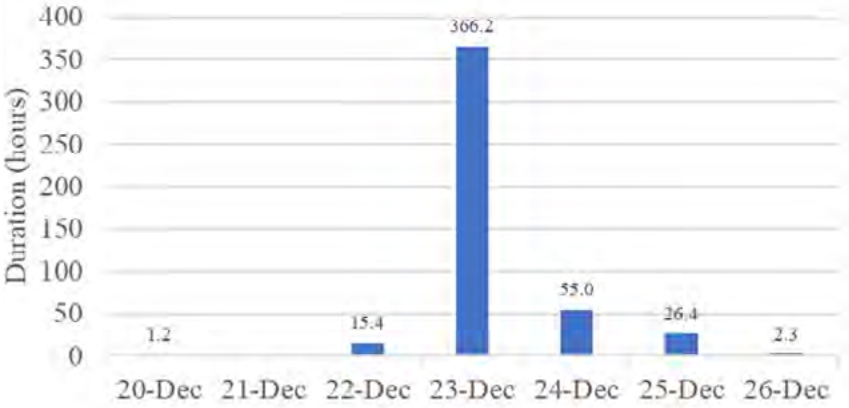
262 Rockies Express Pipeline, LLC, Tariffs, § 21.2 Force Majeure (3.0.0), Columbia Gas Transmission. LLC, Baseline Tariffs, Gen. Terms & Conditions, § 15.1 Force Majeure (0.0.0), Northern Natural Gas Co, Gas Tariffs, Sheet No. 217, G T and C § 10 Force Majeure (1.0.0), Transcontinental Gas Pipe Line Co. Fifth Revised Volume No. 1, Provision and Contract Entitlements, § 11 Force Majeure (5.0.0).

Figure 103: Pipelines - Total Power Outages Reported



Eight of the 15 pipelines reported a total of 53 instances of commercial power loss at their facilities from December 20-26 (shown in Figure 103 above), averaging approximately nine hours in duration, although some lasted longer than three days (see Figure 104, below). Only one power outage impacted shippers because the compressor stations used redundant compressor units powered by gas-fueled backup or portable generation. Of the 15 pipelines that provided data, only four have facilities designated as critical with their electricity provider. Some pipelines stated that they did not see the need to designate critical facilities, while others stated that they prefer to communicate with electric providers during any load shedding events. One pipeline stated that it performed a study following the Event and did not identify any critical site within the service territory of its power provider.

Figure 104: Total Duration of Pipeline Power Outages



D.Grid Entities' Preparedness and Emergency Operations

1. SHORT-TERM LOAD FORECASTING ANALYSIS

A significant majority of the short-term forecasts (4-, 3-, 2-, and next-day peak load forecasts for actual peak loads) for all eight BAs underestimated the actual peak demand. There were only eight instances of the 64 short-term forecasts that overestimated the actual peak demand. The Mean Average Percent Error (MAPE) for all the short-term forecasts for the peak load of December 23 was approximately 11.25 percent and the MAPE for all the short-term forecasts for the peak load of December 24 was approximately 8.51 percent; with an average MAPE of 9.88 percent for both days for all eight BAs. The short-term forecasts generally improved as the day for the forecast peak demand approached, as shown in Figures 19 and 20, in Section III.

The Team identified some of the possible reasons for the underestimation of the actual peak demand: inaccurate weather forecasts, changes in consumer behavior, especially on peak, and changes to the grid (e.g., addition of non-conforming loads or population growth). The Team also found that many of the entities' models lacked the data history (e.g., similar historical days) for the holiday weekend winter peak extreme cold weather conditions forecast. Some BA operators made manual adjustments to the load forecasts to attempt to make them more realistic. Those that used an "adder" to account for potential load forecast error (LG&E/KU, Santee Cooper) had the lowest MAPE for December 24.

While weather-related factors were important, those that did "backcasts" found that their load forecasts were still off even after being corrected for temperature, so clearly temperature was only one factor, although an important one. Multiple entities noted the difficulty of predicting load for a holiday weekend, when there may be few holiday weekends within the historical data available to the model, and few or none of those may coincide with colder-than-ordinary weather. The combination of a holiday weekend plus extreme cold weather made reliance on prior similar days especially challenging. Most entities expected holidays to lower load, but because of the extreme cold, did not see this pattern emerge. A couple of entities mentioned that they had experienced load growth within their service territory, and the importance of being aware of where this load growth is occurring and its composition (is it residential? Data centers? Commercial? Industrial?)

Another important element to identify in an entity's load is the presence of resistive heating. As explained in the 2021 Report in connection with Recommendation 16,[263] as temperatures drop below zero, homes with heat pumps must rely on electric resistance heating, and the hourly electric demand in kilowatts increases sharply as temperatures decline, to up to four times as much as at 32 degrees, once the temperature reaches minus 10.[264] Multiple entities mentioned the fact that temperatures dropped extremely quickly from relatively temperate temperatures to abnormal lows for their area. When temperatures drop very quickly, but homeowners keep their heat set at the same temperature, heating units must run constantly to try to maintain a steady temperature, rather than cycling as is expected and calculated for "normal" winter load forecasts. Some mentioned the severity of the cold—for one entity, three standard deviations beyond their normal December lows—so that they did not have loads at those temperatures in the historical sample of loads used in the load forecasting models (three years for the majority of the entities).

263 "BAs should have staff with specialized knowledge of how weather impacts load, including the effects of heat pump backup heating and other supplemental electric heating . . ." 2021 Report at 225

264 2021 Report at 225 and Figure 108.

2. ANALYSIS OF OPERATIONAL PLANNING PROCESSES

As summarized earlier in Section III, the BAs thought prior to the Event that they individually had sufficient resources to meet their respective expected forecast electricity demands. They anticipated the possibility of some level of unplanned generation outages from the winter storm; they were proactive in their preparation efforts. To determine steps the BAs could take to improve their processes, the Team considered the following outcomes from the Event:

- Most of the BAs underforecast their peak electricity demands experienced on December 23-24.
- The BAs did not anticipate the significant level of unplanned generation outages and derates that would occur during the storm, or the rates at which they would occur, which were similar to the outage rates experienced in Texas during Winter Storm Uri in 2021.[265]
- Many natural gas-fired generating units were unavailable because they had not made advance arrangements for natural gas fuel supply for when they ultimately would be committed to operate, and by the time they were notified of their commitment, natural gas supplies were not available.
- The entities thought that they had sufficient reserves to meet their anticipated peak electricity demands, but the severity and widespread nature of the storm, which left multiple neighboring entities in the same position, forced them into a reactionary state of operation, with limited flexibility, options, or time. As a result, several entities needed to shed firm load.

Short-term planning processes typically use deterministic methods and calculations to develop short range resource plans for the next day or several days in advance of the operating day, with plans easily adjusted for the unplanned outage of one or two generation resources through deterministic recalculations. However, the Team found that preparation for another event like Winter Storm Elliott and other extreme cold weather events would benefit from considering a wider range of outcomes representing greater uncertainty, multiple days in advance of the extreme cold weather operating day in risk areas such as:

- Load forecast
- Generation extreme cold weather availability
- Generation fuel availability
- Multiple-neighboring entity impact
- Transmission system constraints

The Team recognizes consideration of this wider range of outcomes may be seen as suggesting use of long-range planning "probabilistic methods" in the control room. However, because these cold weather events have repeatedly revealed significant differences between what was expected and what the operators actually faced, the Team finds that considering a wider range of outcomes representing greater uncertainty should aid in preparation and decision-making multiple days in advance of future extreme cold weather events like Winter Storm Elliott.

3. ANALYSIS OF EMERGENCY OPERATING CONDITIONS AND COORDINATION

a. Coincident high electricity demands, unplanned generation outages and derates, and many Energy Emergency Alerts

Several of the Core BAs' resource assessments and scenarios for the winter 2022-2023 season relied

265 Section III.B.1. above, describes TVA's unplanned generation outages which increased by 6,000 MW from shortly before 1:00 a.m. to 8:00 a.m. on December 23. Within the PJM footprint, unplanned outages and derates began to escalate shortly after 4 a.m. on December 23, and then from about 8:00 a.m. to 5:00 p.m., they rapidly escalated at a rate of over 2,200 MW per hour. The TVA and PJM experiences were similar to the rate of increase in generation outages and derates that was experienced in the February 2021 event in the ERCOT footprint, from February 14, 10:00 p.m. to February 15, 1:00 p.m. (3-hour period). *See* 2021 Report at 130

on the availability of external generation resources (i.e., purchase power/import power schedules and emergency energy availability) to meet winter season reserve targets. This reliance is dependent on both availability of the power to be imported and on the interregional transfer capability to deliver the power. Some of the BAs' approaches to reliance on external generation resources in planning to serve higher than normal winter peak load levels combined with higher levels of resource outages are as follows:

- One BA identified use of firm transmission (for importing power), combined with economic interruptible energy products for reserves coverage, of 505 MW, 1,519 MW, and 205 MW, for the months of December 2022, January 2023, and February 2023, respectively, to meet its winter reserve above normal load/above normal resource outage scenario margins.
- Another BA assumed 1,000 MW in purchases as part of its 2023 winter season planning and sensitivity analysis.
- One BA calculated a negative reserve margin based on its 90/10 load forecast coupled with expected generation outages, even with use of demand response measures (implying a likely need for purchase power during extreme cold weather conditions).
- Another BA calculated a negative reserve margin based on its 90/10 load forecast without accounting for any generation outages, and with use of demand response measures (again, implying likely need for purchase power during extreme cold weather conditions).

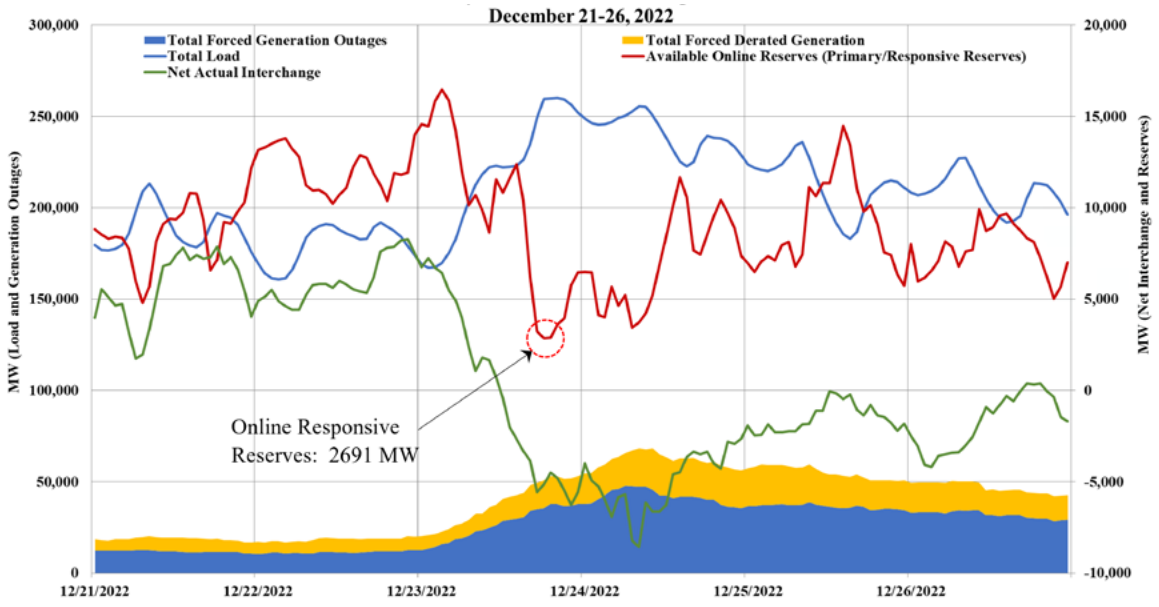
As described above in Section III, during the Event, many BAs in the U.S. Eastern Interconnection had to declare energy emergencies, with some shedding firm load. Most BAs experienced their highest levels of unplanned generation outages and derates and winter peak loads within several hours of one another as Winter Storm Elliott blanketed their footprints simultaneously.[266] A BA's reliance on purchased or import power to meet its system load plus reserves often meant the difference between having to shed load or not. See Figure 39.

System load in the U.S. portion of the Eastern Interconnection increased by 132,000 MW during a 14-hour period coinciding with the arrival of Winter Storm Elliott. By 10 a.m. on December 24, system load levels for several BAs were well above 90 percent of their respective peak loads during Winter Storm Elliott, and most of those BAs had already invoked load management measures (EEA 2) or even firm load interruptions, reducing the percentages which are shown in Figure 39, above. Had the load management and firm load shed measures not been in place, the December 24 peak would have been close to the December 23 evening peak of 482,444 MW (shown in Figure 39, above).

The affected BAs arranged for purchase power imports to cover forecast or actual declining reserves positions that reflected their own unplanned generation outages and derates coupled with rising forecast and actual system loads for December 23 and 24. Those BAs that anticipated potential need and already had prior arrangements for purchase power took steps to schedule those deliveries with the purchase-selling entity (within the source BA) for the coldest days. Because many of the BAs that were in need are directly connected via AC ties as illustrated in Figure 12 (listing the tie lines between BAs), arranging for purchase power imports from a purchase-selling entity within an adjacent BA during less extreme circumstances would normally be fairly straightforward, especially for BAs directly connected to each other like PJM and Duke, or PJM and TVA. But most of the directly-neighboring BAs found themselves simultaneously experiencing Energy Emergencies and did not have energy to share with their neighbors.

266 The five extreme cold weather events in the past 11 years (2011, 2014, 2018, 2021, and 2022) covered large geographic regions. During the 2018 and 2021 events, generation reserves existed in distant operating footprints where the extreme cold weather event was not as intense or had not yet impacted those areas, which afforded the opportunity for power transfers, limited by transmission constraints.

Figure 105: Total Reserves, Generation Outages and Derates, and Load for Event Area: December 21 - December 26, 2022



b. Health of the Eastern Interconnection during Winter Storm Elliott peak electricity demand

The Core Event Area and the U.S. portion of the Eastern Interconnection were experiencing the highest winter electricity demands during Winter Storm Elliott, as shown in Figure 39, above. Meanwhile, while system loads were peaking across the Interconnection, total unplanned generation outages and derates were climbing as shown in Figure 69, above. To gain perspective on the overall health of the Interconnection during this most critical period of the Event, the Team estimated the remaining responsive reserves. The Team reviewed:

- the total online/synchronized reserves in the Core Event Area (see Figure 105),
- the system load of the U.S. portion of the Eastern Interconnection (see Figure 39), and
- total unavailable generation in the U.S. portion of the Eastern Interconnection during the Event (see Figure 37).

The Team found that there were periods during the evening of December 23 and the morning of December 24 when the "potential responsive reserves" (which included online and any offline resources) were lowest while system demand was at its highest levels, as illustrated in Figure 105, below. The Team notes that its estimates of how low responsive reserves dropped are conservative, since they may include offline capacity, and do not account for additional offline capacity in other portions of the Eastern Interconnection.[267] During this same period, Eastern Interconnection frequency excursions were common. Figure 106, below, illustrates one-minute-average system frequency, which declined below 59.95 Hz several times on the evening of December 23 and the morning of December 24 during periods of low responsive reserve capacity.

267 The Team conservatively estimated capacity; the actual capacity shortage could have been worse as the Team did not account for any offline capacity in Canada or the Florida peninsula (i.e., other portions of the Eastern Interconnection), which were not within the Event Area.

Figure 106: Eastern Interconnection Frequency: December 23, 4:00 p.m. to December 24, 12:00 p.m.

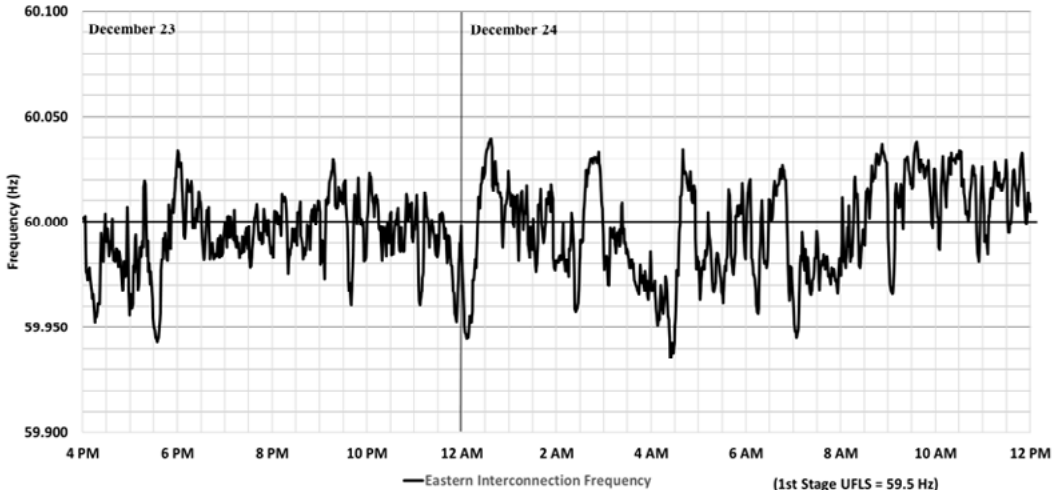
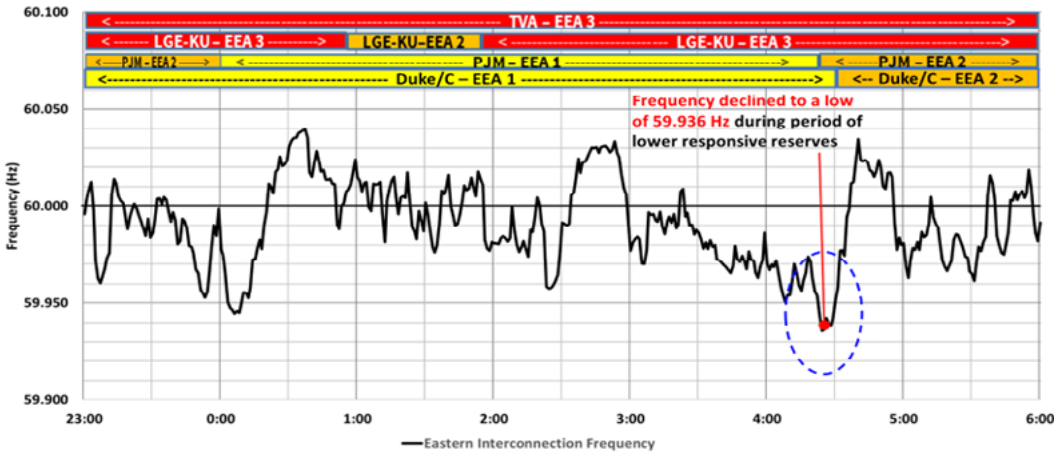


Figure 107: Eastern Interconnection Frequency: December 23, 11:00 p.m. to December 24, 6:00 a.m.



As seen in Figure 107 above, at about 5:40 p.m. on December 23, the Eastern Interconnection frequency decreased to a one-minute average of 59.943 Hz, and dropped to its lowest point during the Event, 59.936 Hz, at about 4:25 a.m. on the morning of December 24. Based on this limited review, the Team is concerned that, accounting for next contingencies (e.g., large generation outage, single point of failure contingency), the Eastern Interconnection appears to have been at risk of potential instability during this timeframe of escalating winter system demands, rapidly escalating unplanned generation outages and derates, and declining responsive reserves.[268]

c. Grid Communications and Coordination

Before and during the Event, RCs remained in contact with each other, as well as with their member BAs, either directly via voice communication or through the NERC-managed Reliability Coordinator Information System (RCIS). RCs were able to communicate EEAs and other emergency measures they took during the Event on the

268 The study should also consider how close the Interconnection may have been to an underfrequency load shed event.

RCIS message system. All RCs have read and write access to the RCIS. Although they do not have write access to the RCIS, BAs and TOPs can request read access to the system. Given the valuable information shared by RCs on the RCIS during emergency events, BAs that have not already done so should request access to the RCIS system and monitor those communications during extreme cold weather events, at a minimum. BAs can also ask their RC to communicate on RCIS their ability, or lack thereof, to provide energy to other BAs experiencing energy shortages during emergencies. This practice could reduce the number of entities that a BA short on energy would need to contact in an emergency.

Generally, many of the RCs have a daily operational call, as well as ad hoc calls and other communications as system conditions dictate. Examples of some of the standing calls relevant to the Event include: (1) NPCC has a brief standing daily 9:30 a.m. call (which includes PJM, MISO, and others), which can be initiated by any RC, and any follow up items from these calls are assigned to control room managers;[269] (2) MISO has a standing daily 8:00 a.m. MISO RC coordination conference call, which includes TOPs and BAs within the MISO Reliability Coordination Area, as well as neighboring RCs, including PJM, SPP, and TVA.

Before and during the Event, RCs coordinated on specific issues and concerns affecting their systems, including the following:

- VACAR-South RC coordinated with adjacent RCs on two potential thermal overloads, one involving a tie line between DEP and PJM and the other involving a tie line between Santee Cooper and Southern. In both cases, the potential overloads were mitigated through the use of adjusted ratings.
- SPP RC agreed to allow an additional increase in the RDT on Saturday, December 24, for an emergency energy request that TVA made from MISO.
- TVA RC coordinated with PJM RC to mitigate real-time overloads within the PJM/AEP footprint on the morning of December 23, and PJM and TVA RCs also coordinated to resolve low voltage conditions observed in the East Kentucky Power Cooperative area.

When conditions permitted, entities directly impacted by the storm provided neighboring entities with emergency energy. Examples included:

- PJM, Duke, MISO, and Southern provided emergency energy to TVA,
- TVA provided emergency energy to LG&E/KU,
- Florida Power and Light and MISO provided emergency energy to Southern, and
- Southern provided emergency energy to DESC.

As described earlier, PJM was able to leverage its simultaneous activation of reserves/SAR procedure with NPCC during the Event.[270] During the evening of December 23, for example, PJM asked NPCC for reserves support (up to 1,500 MW) during the period that PJM activated its Synchronous Reserves emergency procedure. The Team found that the entities communicated and cooperated well during the Event, doing as much as possible to assist their neighboring BAs even while under their own systems were experiencing emergency conditions.

269 *See*, Northeast Power Coordinating Council, Inc., NPCC Emergency Preparedness Communications Procedures (Sept. 2, 2022), https://www.npcc.org/content/docs/public/program-areas/standards-and-criteria/regional-criteria/procedures/c-01-emergency-preparedness-procedure.pdf. (outlining procedures for NPCC ad hoc call).

270 *See* R22 and Attachment B of the NPCC Regional Reliability Reference Directory # 5 - Reserve https://www.npcc.org/content/docs/public/program-areas/standards-and-criteria/regional-criteria/directories/directory-5-reserve-20200426.pdf.

E. Variable Energy Resources' Performance and Uncertainty Analysis

Variable energy resources (VERs) such as wind and solar were part of the energy supply mix during the Event. During the Event, solar and wind comprised 1.94 percent and 1.12 percent of installed capacity, respectively, in the core Event Area, as noted in Figure 11. For PJM, solar and wind comprised 1 percent and 2 percent, respectively, of the net installed generation capacity. Figure 108, below, illustrates the actual generation output by VERs, as a percentage of the total generation production output in the PJM footprint during the Event.

Figure 109, below, shows day-ahead versus actual production profiles of both wind and solar resources in PJM during the Event. Winter Storm Elliott occurred shortly after the winter solstice,[271] resulting in a relatively narrow potential solar production time window each day during the Event.

Figure 108: PJM Percent VER Actual Generation Production Output, December 21 – 26, 2022

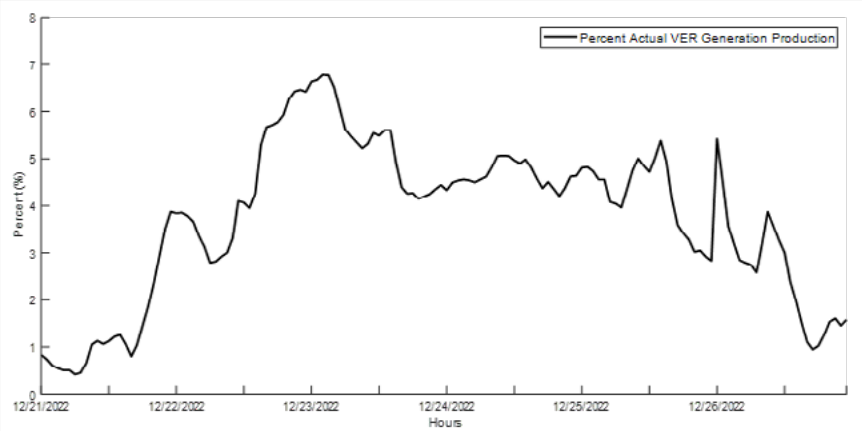
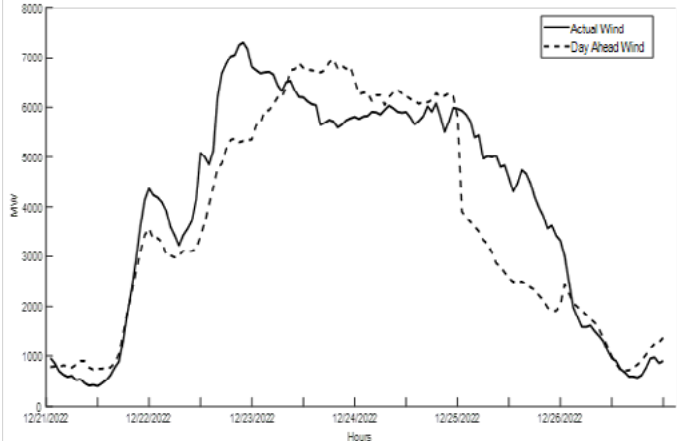
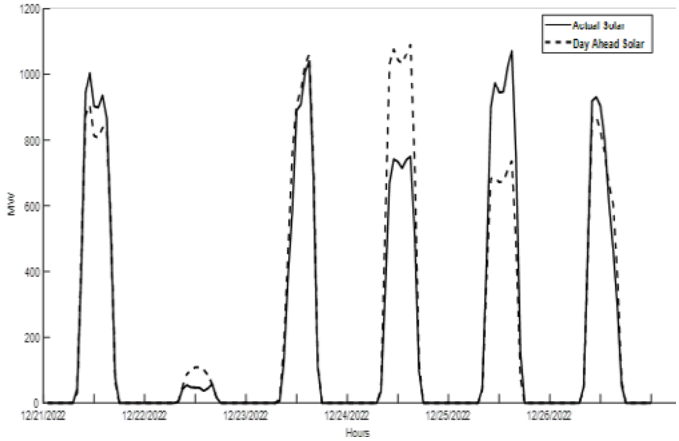


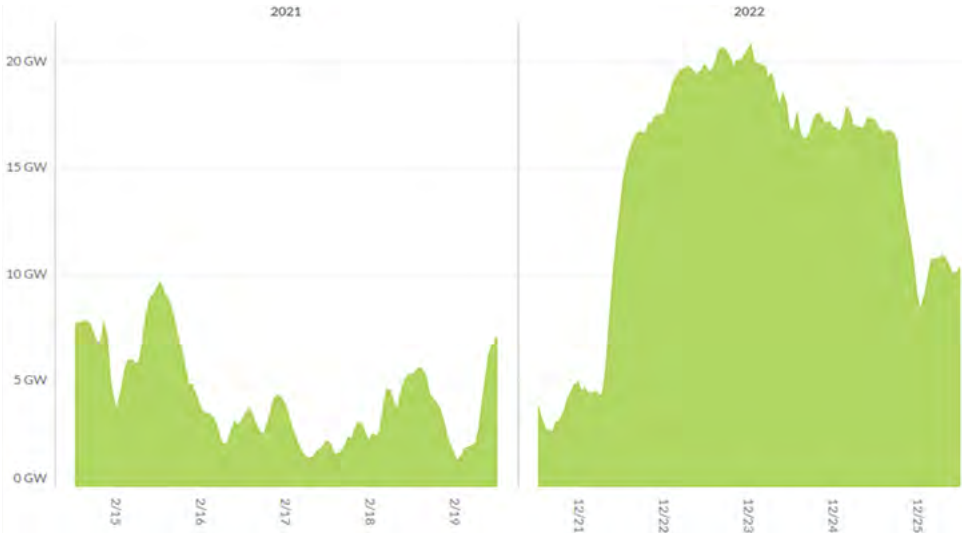
Figure 109: PJM Day-Ahead and Actual Hourly MW Wind and Solar Production, December 21 – 26, 2022





271 Winter Solstice for the Northern Hemisphere was December 21, 2022 4:47 p.m. The winter solstice marks the shortest day and longest night of the year.

Figure 110: MISO Actual Wind Generation – Storms Uri (2021) and Elliott (2022)[272]



The limited availability of solar production time during winter, when daylight hours are shorter, highlights the value of storing energy from solar production for when it is needed most during the winter non-daylight peak load timeframes. For example, DESC noted that on the morning of December 24, their solar resources began to produce energy, which, while after the morning peak, contributed to DESC's ability to pump water at its pumped storage facility so that its capacity would be available for the December 24 evening peak and the December 25 pre-dawn morning peak.

Wind energy production in higher-penetration areas west of the core Event Area (SPP, MISO) was high, especially during the onset of the Event on December 22 and 23. Figure 110, above, shows a wind production comparison between Winter Storm Uri and Winter Storm Elliott in MISO.

For SPP, wind resources performed above accredited capacity on December 22 at 17,900 MW, coinciding with high SPP system load. With high system loads expected to continue, SPP had to anticipate uncertainty including whether the forecast for high wind levels would hold, and the extent to which wind farms would be shut down or derated for low ambient temperatures or high wind cutoff. The actual wind generation output level slowly decreased after the December 22 peak load and reached its lowest level of 2,700 MW 20 hours later, on December 24 at 6 p.m.[273] SPP's experience illustrates the challenge of aligning VER production levels with power grid needs. Absent energy storage opportunities, the higher variability of wind and solar production increases the demand for dispatchable generation with high ramping capacity[274] to balance generation with load during times when wind or solar power is low, and the system is near peak demand.

Understanding and modeling uncertainties with VER production in the operations planning horizon can help minimize reliability and resource adequacy risks, especially at times of system stress, such as during extreme cold weather events. Shifting from deterministic to probabilistic methods for resource availability/adequacy analyses can better model the uncertainties surrounding VER production. See Recommendation 8 in section V.

272 Reprinted with permission of MISO.

273 SPP Report at 6.

274 *See* Department of Energy, *Importance of Flexible Electricity Supply* (May 2011), https://www1.eere.energy.gov/solar/pdfs/50060.pdf.

V. RECOMMENDATIONS[275]

A. Generator Cold Weather Reliability

Each successive analysis of extreme cold weather events has highlighted the need for generating units to proactively prepare for the onset of cold weather events.[276] Each inquiry report has built on previous analyses and findings to explain how generating units can best achieve that end. In August 2021, the Commission approved the adoption of EOP-011-2, effective April 1, 2023, in response to a recommendation from the 2018 Report, and required Generator Owners to have cold weather preparedness plans for their units. The 2021 Report took the next logical step by recommending that generating units be required to "(i) identify cold-weather-critical components and systems and (ii) identify and implement freeze protection measures for those components and systems."[277] The 2021 Report also recommended that generating units that experienced unplanned outages due to freezing should be required to develop Corrective Action Plans to guard against future outages.[278]

More recently, the Commission has approved revisions to the NERC Reliability Standards, in EOP-012-1, that implemented recommendations from the 2021 Report.[279] These changes, the Commission found, "represent[] an improvement to the Reliability Standards and enhance[] the reliable operation of the Bulk-Power System by requiring generator owners to implement freeze protection measures, develop enhanced cold weather preparedness plans, implement annual trainings, draft and implement corrective action plans to address freezing issues, and provide certain cold weather operating parameters to Reliability Coordinators, Transmission Operators, and Balancing authorities for use in their analyses and planning."[280] These modifications have not yet become effective.

Recommendation 1(a): Findings support the need for prompt development and implementation of the remaining recommended revisions to the Reliability Standards from 2021 Report Key Recommendation 1 to strengthen generators' ability to maintain extreme cold weather performance.

Despite the fact that nearly two thirds of all generating units that provided data indicated that they had begun to make improvements to their cold weather preparedness plans in response to the findings of the 2021 Report, and that many units had already begun to implement improvements required under EOP-011-2, R7.3.2, prior to its effective date of April 2023, 111,000 MW of generating units in the Event footprint still experienced unplanned outages, derates or failures to start due to Freezing Issues.[281] The Team considered whether to recommend additional mandatory Reliability Standards, but with many important Standards either approved, but not yet effective, or still in the drafting stage (e.g. identification of generator cold weather critical components, developing Corrective Action Plans

275 Because the recommendations are intended to be shared widely and may be shared without the remainder of the Report, terms that have been otherwise been abbreviated elsewhere in the Report, such as GOs/GOPs for Generator Owners/Operators, will be spelled out the first timethey are used in each recommendation.

276 *See* 2021 Report at 185-86.

277 *See* 2021 Report at 185-86, Recommendations 1(a) and (b).

278 *See N. Am. Elec. Reliability Corp.,* 176 FERC ¶ 61,119, at P 1 (2021).

279 The first of its Requirements become effective October 1, 2024.

280 *N. Am. Elec. Reliability Corp.,* 182 FERC ¶ 61,094, at P 36 (2023).

281 An encouraging finding was that roughly two-thirds of all generating units said they had begun to make improvements to their cold weather preparedness plans in response to the findings of the 2021 Report.

to operate at Extreme Cold Weather Temperatures), this recommendation focuses instead on fully implementing the recommendations already made in response to the 2021 Report. That over 75 percent of the generating units with unplanned outages due to Freezing Issues failed above their documented minimum operating temperatures suggests that work in this area is not yet complete. For additional background and analysis relevant to Recommendation 1(a) see section IV.B.3., above.

Recommendation 1(b): Findings from the Report support the need for robust monitoring by NERC and the Regional Entities of compliance with the currently-effective and approved generator cold weather Reliability Standards, to determine if reliability gaps exist. NERC should identify the generating units that are at the highest risk during extreme cold weather and work with the Regional Entities (and Balancing Authorities, if applicable) to perform cold weather verifications of those generating units until all of the extreme cold weather Standards proposed by the 2021 Report are approved and effective. (Verify highest risk units by Q4, 2023; implement by Q3, 2024)

As mentioned in 1(a), the Team considered recommending additional Reliability Standards, including for several of the sub-parts of Recommendation 1, but was persuaded to focus on fully implementing the 2021 Report recommendations. Robust compliance monitoring of the currently-effective and approved extreme cold weather Standards can help to discern whether there are patterns which suggest that sub-parts of Recommendation 1 may need to be added to the Standards. For example, if compliance monitoring were to show that large numbers of Generator Owners/Operators were not fully-prepared for winter until mid-December or later, it may suggest that Recommendation 1(g) should be considered for addition to the Standards.

Given that the Extreme Cold Weather Preparedness and Operations Reliability Standards will not be fully effective until May 2028, and that generating units continue to experience high volumes of unplanned outages due to the top three causes of Freezing and Fuel issues as well as Mechanical/Electrical Issues, the Team considered what could be done in the meantime to improve generating unit performance to enhance the reliable operation of the grid. The Team recommends identifying those units at the highest risk of unplanned outages due to Freezing Issues (based on generating units' performance in previous events, their responses to NERC's Level 3 Alert or other criteria) for expedited cold weather verifications. The Team also recommends additional near-term, but slightly less expedited, cold weather verifications as explained in the next recommendation.

Recommendation 1(c): Generator Owners/Operators should assess their own freeze protection measure vulnerability, and NERC or the Regional Entities should perform targeted cold weather verifications pursuant to a risk-based approach.

Generator Owners/Operators should not wait for an extreme cold weather event to occur in their Balancing Authority Area, but should learn from the experiences of others, as well as the many resources available.[282] Based on the guidance provided by the Report, the 2021 Report, and the resources available from NERC and the Regional Entities, GOs/GOPs should assess their own freeze protection measures protecting generator cold weather critical components, and determine whether the generator cold weather critical components continue to be vulnerable to extreme cold, the accelerated cooling effect of wind, and precipitation. To determine whether GOs/GOPs are implementing the currently-effective cold weather Reliability Standards, NERC and the Regional Entities should conduct targeted cold weather verifications, using a risk-based approach. The GOs/GOPs selected would not be those considered at the highest risk of unplanned outages due to Freezing Issues, (i.e., those that are targeted by Recommendation 1(b)), but should be those in the next tier of risk and below. These verifications

282 *See* note 52 for a list of resources.

should continue until all of the Reliability Standards revisions recommended by Key Recommendation 1 of the 2021 Report have become effective. For additional information in support of Recommendation 1(c) see Key Recommendation 1 in the 2021 Report.

Recommendation 1(d): Generator Owners/Operators of generating units that have experienced outages, derates, or failures to start above their documented operating temperature limits should consider conducting engineering design reviews to: (1) evaluate the accuracy and completeness of existing design information (including as it relates to the documented operating temperature limits) and calculated extreme cold weather operational thresholds: (2) evaluate whether existing freeze protection measures are adequate to protect their identified generator cold weather critical components; (3) evaluate whether design features to address cold weather and freezing conditions are being optimally implemented; (4) evaluate the impact of any modifications or additions to the original design on the documented operating temperature limits; (5) evaluate whether any modifications or additions resulted in new generator cold weather critical components; (6) evaluate the impact a unit's "cold" versus "hot" status has on its design limits, including the identification of a "cold start-up" temperature for each unit, if applicable; and (7) determine whether the generating unit's operating characteristics have been altered in a way that creates a potential "weak link" component.

The Team recommends that Generator Owners/Operators consider taking additional steps to ensure the reliability of their generating units for the substantial number of units that, during Winter Storm Elliott, experienced Freezing Issues at temperatures above their documented operating temperature limits. The failures above the units' documented operating temperature limits suggest that the information relied upon by many generators may be inaccurate or may no longer be valid after modifications made to the generating units. Generator Owners/Operators that have experienced unplanned outages, derates, or failures to start due to freezing during extreme cold weather events should consider reviewing their documented operating temperature limits, with appropriate expert assistance, to determine whether modifications have changed their limits or whether the limits should be changed for some other reason. A generating unit may have a higher "cold" low temperature limit (the temperature at which it can start in extreme cold weather, when it has not already been running, versus the "hot" temperature, at which it can run continuously). Identifying these temperatures and sharing them with the BA is critical. However, the Team cautions against GOs/GOPs simply raising their documented operating temperature limits to temperatures above those at which the units failed during the Event, without analyzing whether the units could perform at lower temperatures with appropriate protection of their cold weather critical components.

Recommendation 1(e): Generator Owners/Operators should consider conducting operational/functional testing of their "active" freeze protection systems.

Generator Owners/Operators should consider conducting operational and functional testing of their "active" freeze protection systems (e.g., heat trace circuitry/controls, partial discharge recirculation systems) on at least an annual basis, and always prior to winter, to ensure their continued functionality during extreme cold weather events. Like other systems, active freeze protection systems are subject to wear and tear over time. For instance, even a small section of inoperable heat trace system or circuit can leave a critical component unprotected, leading to a freezing-related outage. A heat trace system that no longer properly alarms for circuits that are inoperable will not warn the GO/GOP that its critical components are vulnerable to freezing.

Recommendation 1(f): Generator Owners/Operators should communicate their low temperature limits, and changes to those limits, to their Balancing Authority and Reliability Coordinator on a real-time basis.

Discussions with Balancing Authority representatives while preparing the Report underscored the substantial

efforts that BA personnel took in real time to activate generation; only for them to learn that that the generation was unavailable. As noted in PJM's analysis of its own response to Winter Storm Elliott, on the afternoon of December 24, 2022, its operational situation was "strained" in part because of a lack of reliable information of this kind:

> *PJM had put generation resources on notice, through Advisories and Alerts, of PJM's need for them to be prepared to run. PJM relied on Generator Owner/operator-submitted data and believed these reserves were available. In many cases, this data did not reflect the actual capability of the generator and PJM would only learn of the generation resource failures at the time PJM was expecting these resources to begin to run.*[283]

Balancing Authorities seeking to address cold weather events should not be expected to learn such information on an ad hoc basis while simultaneously attempting to respond to worsening generation conditions and/or increased load. The onus should be placed on generating units to communicate and update such information, in real time, to BAs. If a GO/GOP knows that there is a meaningful difference between its cold start-up temperature and the temperature at which it can continue to operate when warm, the GO/GOP should inform the BA, so that the BA can consider the generating unit for pre-operational warming in advance of extreme cold weather events. Before an extreme cold weather event, GOs/GOPs should consider whether high winds or precipitation might affect their ability to perform at the documented low temperature limit(s) that they provided to the BA. Generator Owners/Generator Operators should update this data in real time, and BAs should consider amending their tariffs or procedures to require real-time updates if not already required. BAs should use all information provided by GOs/GOPs regarding the operating limits of their generating units to the fullest extent possible in their operations.

Recommendation 1(g): Generator Owners/Operators should complete their preparations for winter, including implementing their winter preparedness plans and inspecting and maintaining their generating units' freeze protection measures, no later than the earliest first freeze date for the generating unit's location, as determined by National Oceanic and Atmospheric Administration data.[284] Generator Owners/Operators should maintain those preparations until after the last freeze date, as provided by the same data. Those preparations are in addition to any preparations, inspection or maintenance done in anticipation of a specific extreme cold weather event.

Although annual inspections and maintenance of generating units' freeze protection measures are required by EOP-011-2 R 7.2, some evidence suggests that Generator Owners/Operators may not have completed freeze protection maintenance on all of their units before Winter Storm Elliott hit, relatively early in the winter. Winter Storm Elliott is not the only proof that the worst weather can happen early in the season—in the 2021 Report, Appendix B examined five extreme cold weather events that impacted Texas and the South Central U.S. Two of those events happened in December, one in January, and two in February. December is too late for GOs/GOPs to be finishing their preparation for winter.

(1(c) to 1(g): Implement as soon as possible, but by no later than Q4, 2025)

Recommendation 2: NERC should initiate a technical review of the individual causes of cold-weather-related unplanned generation outages caused by Mechanical/Electrical Issues during the Event to identify the root causes of these failures with the goal of determining what can be done to reduce the frequency of these outages during extreme cold weather events. The study should also consider whether additional Reliability Standards are appropriate to address the root causes of these issues. The study should be conducted by

283 PJM Report at 28.

284 *National Weather Service Frost and Freeze Information* (Sept. 2022), https://www.weather.gov/iwx/fallfrostinfo.

either an independent subject-matter expert such as the Electric Power Research Institute or an academic institution, with participation by Generation Owners/ Generation Operators on scoping and providing generating-unit-specific technical expertise. (Initiate Technical Review by Q1, 2024)

Successive reports reviewing cold weather events have consistently demonstrated a steady relationship between decreasing temperatures and a rise in Mechanical/ Electrical Issues in generating units. The 2021 Report suggested that further analysis was required by Generation Owners to "understand the impact of extreme cold weather on mechanical/electrical failures, so that GOs can identify possible methods of reducing the incidence of unplanned outages, derates and failures to start due to [Mechanical/Electrical Issues] during similar events."[285] The persistence of these issues, even in the face of increased awareness, suggests further action needs to be taken.

An independent subject matter group with knowledge of electrical generator design and operations, as well as materials science, among other topics, should study the relationship between Mechanical/Electrical Issues and cold weather events. The study should analyze the types of Mechanical/Electrical Issues experienced by generating units during extreme cold weather events; the types of components and systems most vulnerable to these events; methods and best practices to prevent Mechanical/Electrical Issues from affecting those components and systems; and any other information deemed relevant. Further, the study should differentiate between Mechanical/Electrical Issues caused by extreme cold weather events, and those that simply occurred during such events (e.g., boiler tube leaks).

Recommendation 3: A joint NERC-Regional Entity team, collaborating with FERC staff, should study the overall availability and readiness of blackstart units to operate during cold weather conditions. This study should cover all portions of the U.S. not already studied, and should incorporate existing literature, studies, reports, and other analyses as to the availability and readiness of blackstart units. The scope of the study should include:

- **an evaluation of existing blackstart restoration plans, including a review of potential single points of failure related to natural gas system dependence;**
- **an evaluation of the sufficiency of existing blackstart availability, readiness, and testing criteria, including whether unscheduled, unannounced, or criteria-based testing (e.g., those used in ERCOT) would improve reliability during cold weather events;**
- **the need for ensuring that generating units with dual-fuel capability providing blackstart service have appropriate fuel storage (as determined by the Balancing Authority);**
- **the need to require blackstart generators to test their fuel switching capabilities seasonally;**
- **the need to require additional fuel storage due to import constraints;**
- **the need for Transmission Operators to incorporate generating units' cold weather preparations into the qualification process for certifying generators as blackstart units; and,**
- **any other subject areas identified as areas of substantial interest or concern in the report issued as a result of ongoing efforts to study blackstart unit availability and readiness in ERCOT.[286] (Initiate study by Q1, 2024)**

Over 19,000 MW of blackstart designated generating units (155 units) incurred outages, derates, or failures to start during the Event. Of the 155 units, 119 were natural-gas fueled units (accounting for just under 75 percent of all generation lost by blackstart designated units). These failures were not geographically or causally isolated, instead, they covered the entire area impacted by the Event, arose from Freezing Issues, Mechanical/Electrical Issues, and Fuel Issues, and impacted gas, oil and dual-fuel capable units.

285 2021 Report at 218 (Recommendation 11).

286 *See* 2021 Report Recommendation 26.

The readiness and availability of blackstart units is paramount to the reliability of the grid during extreme weather scenarios, and the breadth (both in numbers and causes) of the outages and derates to blackstart units during Winter Storm Elliott suggests the need for systematic evaluation of the readiness of these units. For additional background and analysis relevant to Recommendation 3, see Section IV.B.4.

B. Natural Gas Infrastructure Cold Weather Reliability

Recommendation 4: Legislation by Congress and state legislatures (and/or regulation by entities with jurisdiction over natural gas infrastructure reliability) is needed to establish reliability rules for natural gas infrastructure necessary to support the grid and natural gas local distribution companies that address the needs described in 4(a), (b) and (c).

The 2021 Report noted that "the reliability of the BES depends, in large part, on the reliability of the natural gas infrastructure system, but unlike the BES, with its mandatory Reliability Standards enforced by FERC and NERC, the reliability of the natural gas infrastructure system rests largely on voluntary efforts."[287] In February 2011, extreme cold weather in Texas and New Mexico "resulted in widespread wellhead, gathering system, and processing plant freeze-offs in the Permian and San Juan basins," reducing flow by approximately 20 percent, a much greater extent than had occurred up to that point. LDCs interrupted gas service to more than 50,000 customers in New Mexico, Arizona, and Texas, including the cities of El Paso, Texas, Tucson, Arizona and Taos, New Mexico. While some LDCs were able to restore service within hours because they had only cut a few customers, it took one LDC a week to restore 4,300 customers, using a workforce of 700. The 2011 Report recommended that state legislators and regulators, working with "all sectors of the natural gas industry. . . should determine whether production shortages during extreme cold weather events can be effectively and economically mitigated through the adoption of minimum, uniform standards for the winterization of natural gas production and processing facilities."[288] The 2011 event highlighted the increasing interdependency of natural gas infrastructure and the BES.[289]

In Winter Storm Uri, Natural Gas Fuel Issues were "the second-largest cause of generating unit outages that left residents without heat and light and energy in ERCOT for nearly three days, during freezing temperatures,"[290] even though that event did not involve LDCs interrupting service to customers. Texas natural gas production declined during Winter Storm Uri by 70.1 percent, Oklahoma, by 56.8 percent, and Louisiana, by 53.5 percent,[291] while the lower 48 states' production declined by 28 percent.[292] Like the 2011 Report, the 2021 Report recognized that freezing at the wellheads and other natural gas infrastructure facilities, as well as weather-related road conditions, caused the majority of the gas production decline that contributed to the Natural Gas Fuel Issues. To prevent recurrence of these dramatic drops in production in areas on which the entire United States relies for the production of natural gas, the 2021 Report recommended that "Congress, state legislatures, and regulatory agencies with jurisdiction over natural gas infrastructure facilities should require those natural gas infrastructure facilities to implement and maintain cold weather preparedness plans,

287 2021 Report at 197.

288 2011 Report at 126-132, 212, 214.

289 As the 2021 Report recorded, "[a]fter the 2011 event, the Commission initiated a proceeding (Docket No. AD12-12-000) in early 2012, requesting comments on questions about topics including market structure and rules, scheduling, communications, infrastructure, and reliability." The Commission convened five regional conferences and issued two orders which enhanced pipeline communication with grid entities and increased pipeline scheduling flexibility. The 2021 Report noted "some aspects of the problem are either outside [the Commission's] authority or require cooperation among jurisdictions" (e.g. the natural gas production shortages). 2021 Report at 201.

290 2021 Report at 197.

291 As compared to January production. 2021 Report at 174. The Team used January so that it could compare the 2011 event, which happened February 1-5.

292 As compared to February 8 production. 2021 Report at 174.

including measures to prepare to operate when specific cold weather events are forecast."[293]

Despite the 2011 and 2021 recommendations for protecting natural gas infrastructure, including wellheads, from extreme cold weather, production remained insufficiently protected during the Event, which led to a reliability-threatening Gas Emergency for Con Edison in New York City. Had its entire system been cut off, Con Edison said it would have taken "many months" to restore service to its million-plus customers, even with mutual assistance, leaving natural gas customers without heat in the middle of winter. No regulatory entity is tasked with ensuring the *reliability* of the natural gas fuel supply relied upon by the BES/grid. The Team recommends that Congress exercise its regulatory power over natural gas infrastructure necessary to ensure grid reliability. Congress could consider whether additional or exclusive authority for natural gas infrastructure reliability should be placed within a single federal agency, as it did with bulk power system reliability in 2005, when it added section Federal Power Act section 215.[294]

Recommendation 4(a): Because extreme cold weather events have repeatedly impaired the production, gathering, processing, and transportation of natural gas, the reliability rules suggested in Recommendation 4 should address, among other topics, the need for natural gas infrastructure reliability rules, from wellhead through pipeline, requiring cold weather preparedness plans, freeze protection measures, and operating measures for when extreme cold weather periods are forecast, and during the extreme cold weather periods.

The last two extreme cold weather events resulted in substantial natural gas wellhead production declines in key locations. In 2021, Texas, Oklahoma and Louisiana saw 50-percent-plus declines, with Texas most impacted with a 70.1 percent decline. In the Event, the Marcellus and Utica Shale formations of the Appalachian Basin declined by 23 and 54 percent, respectively. "On its own, the Appalachian Basin would have been the third-largest natural gas producer in the world [for] the first half of 2021, behind Russia and the rest of the United States."[295] The largest percentage of natural gas production declines were freeze-related in the Event, and this was also true in 2021.[296]

Unlike in Winter Storm Uri, the natural gas production areas most affected during the Event were in areas that routinely experience cold weather. All of the gas producing entities that provided data about outages and disruptions to their facilities had implemented some cold weather preparedness activities for winter. The combination of the rapid temperature drops, and strong winds defeated many of the protections that were put in place. The interrelated nature of the natural gas supply chain added to its vulnerability. See generally IV.C. Each

293 Key Recommendation 5, 2021 Report at 194. Recognizing that mandatory natural gas infrastructure reliability rules would not likely be in place for the upcoming winter, the 2021 Report also recommended multiple practices that natural gas infrastructure entities could voluntarily implement. Some could be quickly implemented, such as obtaining emergency back-up generators, pre-draining storage tanks before severe weather, or manning key facilities around the clock. Key Recommendation 6, 2021 Report at 194.

294 The NAESB Forum Chairs recommended "**a natural gas reliability organization akin to the one currently responsible for electric reliability, NERC**," NAESB Report at 3 (emphasis in original). Similarly, the National Academy of Science, in its 2021 report on the Future of Electric Power in the U.S., The Future of Electric Power in the United States | The National Academies Press, recommended that the Commission "designate a central entity to establish standards for and otherwise oversee the reliability of the nation's natural gas delivery system. Congress should also authorize FERC to require greater transparency and reporting of conditions occurring on the natural gas delivery system to allow for better situational awareness as to the operational circumstances needed to help support electric system reliability." National Academy of Sciences (nasonline.org).

295 Corinna Ricker and Warren Wilczewski, Shale natural gas production in the Appalachian Basin sets records in first half of 2021, Today in Energy (Sept.1, 2021) U.S. Energy Information Administration - EIA - Independent Statistics and Analyhttps://www.eia.gov/todayinenergy/detail.php?id=49377sis.

296 Fifty-eight percent of production declines in the 2021 event were caused by freezing or severe cold weather, including "production declines directly caused by freezing, preemptive shut-ins to protect natural gas facilities from freeze-related impacts, and poor road conditions (due to precipitation) that prevented the removal of fluids from production sites or access to facilities to make necessary repairs." 2021 Report at 175.

part of the natural gas supply chain is dependent upon the reliability of other sections, which increases the importance of requiring all sections of the natural gas supply chain to protect against the effects of extreme winter weather. Regulators should develop winterization guidelines to protect and continue the operations of production, gathering and processing system facilities during extreme weather events.[297] Those guidelines should address issues arising from low temperature and high winds, as well as precipitation (if precipitation meaningfully worsens the effect of cold on the applicable natural gas infrastructure).[298]

Recommendation 4(b): The reliability rules suggested in Recommendation 4 should address, among other topics, the need for regional natural gas communications coordinators, with situational awareness of the natural gas infrastructure similar to the grid's Reliability Coordinators, that can share timely operational communications throughout the natural gas infrastructure chain and communicate potential issues to, and receive grid reliability information from, grid reliability entities.

During the Event, both Balancing Authorities and natural gas infrastructure entities such as Local Distribution Companies had limited situational awareness as to the extent to which natural gas production losses rippled through the interconnected systems. PJM headed into the operating day of December 23 expecting approximately 158,000 MW of available generation to meet a forecast load of 127,000 MW. But PJM did not anticipate the rapidly escalating generation outages that peaked at over 46,000 MW early on December 24, 70 percent of which were natural-gas-fired units.[299] PJM was unaware of the magnitude of the natural gas production losses despite the fact that PJM's Gas Electric Coordination Team conducts daily reviews during the winter months (November through March) of the interstate pipeline bulletin boards to assess pipeline operating conditions, identify potential natural gas supply risks to the natural gas-fired generation fleet, and provide daily gas risk assessment reports to its dispatch personnel. Con Edison also did not anticipate that it would be notified of potential severe operating pressure reductions that would not recover unless demand was reduced. Pipelines necessarily had to have been aware of decreasing receipts at various points as pressures began to drop. While producers may have had flexibility to make up their nominations over the course of a day, shippers were unaware of what was happening in real time and did not know that the gas they had purchased and nominated had not been delivered to the pipeline until notified of sometimes very large cuts in nominations on December 24.

Operating personnel at the wellhead communicate with gatherers and processors to which they deliver their gas, gatherers and processors communicate their operational issues to the pipelines to which they deliver gas, and pipelines communicate operational issues to their shippers. Although natural gas infrastructure entities often communicate marketing information to end-use customers, in accordance with contractual obligations, it is not the norm for them to communicate with grid operators (e.g., BAs and RCs). Instead, news of operational issues is often communicated in piecemeal fashion from the affected operator to the next operator in the gas production and delivery chain. Absent any informal arrangement to share information, grid operators and Generator Owners/Operators typically receive information about pipeline operational issues only in the form of operational flow orders and critical notices, which often are issued many hours after the issues begin to occur upstream. There is no natural gas infrastructure entity that has the system-wide view as

297 This recommendation is also consistent with Recommendation 16 from the NAESB Report, which stated, in part, that "applicable state authorities should consider the development of weatherization guidelines appropriate for their region/jurisdiction . . .." NAESB Report at 58-59.

298 *See* 2021 Report at 194-95 (Recommendation 6, which included a long list of measures that natural gas infrastructure entities could use to protect against freezing and other cold-related limitations).

299 *See* PJM Report at 2.

the RC does for the grid. The NAESB Report recognized the "importance of a wide-area view of natural gas system operations to help ensure reliability and the value of being able to access timely data to assist in operational planning, particularly during critical events or anticipated critical events."[300] While interstate pipelines are required to post certain information on their electronic bulletin boards, intrastate pipelines generally have no such requirements.

Multiple entities, including gas and electric trade groups, BAs and RCs, and GOs, described various information gaps existing in the operations of natural gas infrastructure. Many requested that intrastate pipelines be required to post data similar to what interstate pipelines post on their electronic bulletin boards.[301] A generation trade group noted that increased intrastate transparency would assist "particularly in the posting of actual flow data that can assist in validating force majeure claims and posting of available capacity to assist in identifying locations for additional supply/capacity."[302] An Regional Transmission Organization/Independent System Operator complained about the timeliness of information, noting that "last minute force majeure calls" were the only information they received about availability of commodity during the Event.[303] One entity pointed out that "[s]ince most intrastate pipeline operators also own and operate interstate pipelines, they already have the necessary infrastructure and knowledge of how to accomplish this information sharing at minimal cost and effort."[304] Finally, one trade group argued that the intrastate pipelines' lack of transparency combined with their ability to control both capacity and transportation posed a reliability risk:

> The lack of separation between pipeline operational and marketing functions allows intrastate pipelines to operate as regional monopolies and exert market power in the pricing of gas supply services particularly during time of high demand during extreme weather events, such as Winter Storm Uri. Customers are then forced to choose between exorbitant prices or the real prospect of having no access to natural gas supplies. This lack of competitive choice affects both the system reliability as well as the cost to gas and electric end-use customers.[305]

Based on their experience during the Event, shippers indicated that helpful changes would include providing information *linked to specific receipt points, as soon as possible, updated as often as possible, that included information about the volumetric effect at various receipt points if possible.* NAESB Report Recommendation 1 suggested that FERC could improve the timeliness of information available by directing NAESB to revise its business practice standards related to the timely reporting of natural gas pipeline informational website

300 November 8, 2022 GEH Forum Meeting Staff Notes (NAESB Report at 18 n.68). The NAESB Report found that some information sharing between natural gas and grid entities was supported by FERC Order No. 787, which permits the communication between certain parties of operational information to support reliability of natural gas and electric systems, as well as the NAESB WEQ and WGQ Business Practice Standards, incorporated by reference as part of 18 C.F.R § 38.1(a) and 18 C.F.R § 284.12. However, it also noted that some BAs and RCs (a/k/a ISOs/RTOs in their market roles) stated that there are challenges in accessing and analyzing such information. (NAESB Report at 18 nn. 69, 71).

301 *See*, e.g., comments of Electric Power Supply Association, (Page 93, GEH Survey Response Comment Submissions – February 27, 2023) https://naesb.org/pdf4/geh030323w5.docx; comments of Texas Competitive Power Advocates, Page 144, GEH Survey Response Comment Submissions – February 27, 2023) https://naesb.org/pdf4/geh030323w5.docx; comments of Process Gas Consumers Group and American Forest & Paper Association, Page 144, GEH Survey Response Comment Submissions – February 27, 2023) https://naesb.org/pdf4/geh030323w5.docx

302 (Page 144, GEH Survey Response Comment Submissions – February 27, 2023) https://naesb.org/pdf4/geh030323w5.docx.

303 Comments of PJM Interconnection, LLC, combined comment record at page 258.
PJM (Page 118, GEH Survey Response Comment Submissions – February 27, 2023) https://naesb.org/pdf4/geh030323w5.docx.

304 Comments of Texas Competitive Power Advocates, combined comment record at page 284.
TCPA (Page 144, GEH Survey Response Comment Submissions – February 27, 2023) https://naesb.org/pdf4/geh030323w5.docx.

305 Comments of Texas Competitive Power Advocates, combined comment record at page 288.
TCPA (Page 148, GEH Survey Response Comment Submissions – February 27, 2023) https://naesb.org/pdf4/geh030323w5.docx.

posting data;[306] enabling the data to be accessible to grid operators as soon as it is reported and available. Additionally, to address the fact that BAs and RCs are reliant on 24/7 operations while some natural gas infrastructure and marketing entities are not available around the clock, NAESB Report Recommendation 7 suggests that natural gas infrastructure operations be fully functioning on a 24/7 basis in preparation for and during events in which extreme cold weather is forecast.[307]

RCs and BAs could use improved information provided to better plan their operations during periods of extreme cold weather. BAs could dispatch more or different generation. For example, PJM could have dispatched long-lead-time units had it known the number of natural gas-fired generating units that would likely have failed to perform. Natural gas-fired generators could seek or activate alternate fuel supply or transportation arrangements (e.g., fuel oil (for dual-fuel units), natural gas storage, switch transportation to another pipeline if the facility is served by more than one pipeline). LDCs could act more quickly to preserve their system reliability (both for their commercial and residential customers as well as to maintain deliveries to any behind-the-citygate generation)[308] and reduce their draw on already-challenged pipelines during extreme cold weather conditions. For example, Con Edison used its LNG facility to preserve necessary system pressure at its citygate, but would have started it earlier, had it known how production declines were likely to affect delivery at receipt points.[309] Recommendation 4(b) differs from Recommendation 5 primarily in scope and timing, as well as prerequisites for achieving the outcome. Recommendation 4(b) seeks natural gas infrastructure entities that have the tools and authority to have the wide-area view, like a Reliability Coordinator does for the grid, and will likely rely on legislation and/or regulation; Recommendation 5 seeks near-term improvements in information sharing that do not require legislation or regulation.

Recommendation 4(c): The reliability rules suggested in Recommendation 4 should address, among other topics, the need to require natural gas infrastructure entities to identify those natural gas infrastructure loads that should be designated as critical for priority treatment during load shed and provide criteria for identifying such critical loads.

Recommendations from the 2011 Report[310] and the 2021 Report[311] highlighted the importance of Transmission Owners/Operators and Distribution

306 For example, operationally available capacity, total scheduled quantity, and any other data necessary to assist regional operators in maintaining system reliability. The NAESB Report noted, "There was substantial support from both electric and natural gas participants to explore ways to streamline and add efficiencies to the reporting, posting, and data sharing processes of natural gas pipelines (NAESB Report 17 n.62).

307 To address these differences, NAESB Recommendation 7 suggested that "[s]tate public utility commissions and applicable state authorities in states with competitive energy markets should engage with producers, marketers and intrastate pipelines to ensure that such parties' operations are fully functioning on a 24/7 basis in preparation for and during events in which extreme weather is forecast to cause demand to rise sharply for both electricity and natural gas, including during weekends and holidays. (States could consider the approaches adopted in FERC regulations affecting the interstate pipelines.) In instances where state authorities lack enabling authority to take such actions, the FERC should adopt regulations to achieve identical outcomes within its authority."

308 For example, Con Edison's distribution system served 19 generating units.

309 More accurate and timely information from upstream entities could also help LDCs when to use their demand response and requests for voluntary customer conservation. Both are important tools for managing the tight conditions during extreme cold weather events. The NAESB Report recommended that State public utility commissions encourage LDCs within their jurisdictions to "structure incentives for the development of natural gas and electric demand-response programs" and "to provide voluntary conservation public service announcements for residential, commercial and industrial customers" "in preparation for and during events in which demand is expected to rise sharply for both electricity and natural gas." NAESB Report, Recommendations 10 and 11, at 44-45. NAESB Recommendation 10 was supported by 91 percent of the Wholesale Gas Market and 91 percent of the Wholesale Electric Market, as those terms are defined in the NAESB Report. Id. at 44-45. NAESB Recommendation 11 was supported by 93 percent of the Wholesale Gas Market and 100 percent of the Wholesale Electric Market, as those terms are defined in the NAESB Report. Id. at 45.

310 Recommendation 25, 2011 Report at 211-12.

311 Key Recommendation 1i, 2021 Report at 208.

Providers performing critical load reviews of gas production and transmission facilities and prioritizing critical loads during load shed. Few natural gas facilities were impacted by power outages during the Event, as compared to Winter Storm Uri, because the volume of load shed paled in comparison to ERCOT's 20,000 MW during Winter Storm Uri. But the Team was concerned to find that few natural gas infrastructure entities designated *any* of their facilities as critical loads to their local electricity provider.

All 10 of the natural gas producers who provided information in conjunction with the inquiry responded that they do *not* identify *any of their facilities* as protected or as critical loads even though winterization systems including heat trace can be dependent upon utility-provided electric power. Their utility-powered natural gas production facilities also have no, or limited, alternate or backup power. The Team is aware of producers that do rely on the grid for their electricity but have not identified any of their facilities as critical loads.

Of the two gathering system operators from whom data were collected, one indicated that its gathering system compression facilities do not depend on utility/grid power, but it does depend on the utility power to operate air compressors to maintain emergency shut- down valve positions, start the units and operate control equipment within the facility. Gas-fired backup generators are available at the stations in the event of a power outage to the air compressors/system at the majority of their facilities. The second entity indicated that utility power is its primary source of power. Several of its facilities rely heavily on electricity for gas compression and delivery capacity for a significant portion of their operations, and a loss of electrical power would result in the inability to transport and process large quantities of gas. Only 25 percent of the 26 processing plants that provided data were protected from power outages by local power provider critical load designation agreements.

Of the 15 interstate pipelines that provided data to the Team, four stated that they have facilities designated as critical with their power provider, and 11 provided reasons for not designating any facilities.[312] In total, four pipelines designated 60 facilities as critical. The majority of those facilities (42) are owned by a single pipeline. Pennsylvania had the most identified in a single state, with nine.[313]

The Team recommends that legislative and regulatory actions be taken to either establish criteria for natural gas infrastructure facilities to be designated as critical or create or designate an agency or entity to establish such criteria. The critical facilities identified should then be required to register with or otherwise communicate to their electric service necessary information about their critical natural gas infrastructure facilities such as location. Facilities could include producers, gathering/compressing facilities, processing facilities, and both intrastate and interstate pipelines. Legislators or regulators can look to the collaboration between the Public Utility Commission of Texas and the Texas Railroad Commission on rules for designating natural gas facilities and entities as critical, which was required by Texas House Bill 3648, in the wake of Winter Storm Uri's devastating effects on Texas. On November 30, 2021, the Public Utility Commission and Railroad Commission separately adopted rules to codify HB 3648 and establish new regulations for electric utilities and natural gas entities to ensure critical natural gas facilities are appropriately identified.[314]

312 *See* Section IV.C.4 for a discussion of the reasons given for not identifying facilities as critical.

313 The other states and number of critical facilities identified were Virginia (6), New York (5), Kentucky (4), Alabama (3), Tennessee, Mississippi, Ohio, Georgia, and New Jersey (all with two or fewer).

314 https://www.puc.texas.gov/industry/electric/cng/default.aspx

C. Natural Gas-Electric Coordination for Cold Weather Reliability

Recommendation 5: The North American Energy Standards Board should convene natural gas infrastructure entities, electric grid operators, and LDCs to identify improvements in communication during extreme cold weather events to enhance situational awareness. (Q2, 2024)

This Recommendation differs from Recommendation 4b in that it does not seek legislation or regulation but seeks near-term options for enhancing situational awareness among natural gas infrastructure and electric grid entities. The Team recognizes that producers, processors, interstate and intrastate pipelines, as well as grid operators such as Balancing Authorities and Reliability Coordinators, could improve their real-time coordination and communication to some extent without the need for a Reliability Coordinator-equivalent for natural gas infrastructure.

There is a need for improved communication among the operators of production facilities (producers, gatherers, processors) and the timely dissemination of this coordinated communication from the production facilities to other natural gas infrastructure entities, BAs, shippers, and end-use customers (i.e., Local Distribution Companies). Discussions should include what should be communicated, how it should be communicated, and to whom it should be communicated. In particular, operators of gas production facilities should provide information to the extent that they are aware of situations that may have potential adverse impacts on the BAs, pipelines, LDCs, and/or shipper reliability, whether such information becomes available before or during extreme weather events. Ideally those communications would include aggregated volume data or confirmed scheduled quantities for key upstream receipt points on the pipeline systems. Information about operational issues (e.g., location, estimated duration of outage) should be communicated to BAs, LDCs, and shippers so they can anticipate and plan for potential critical notices, OFOs or force majeures, rather than react after those notices are issued. Communication can occur without endangering sensitive commercial information, as it does on the BES grid side, by, among other methods, separating the operational employees who share information from the marketing employees.

NAESB Report Recommendations 2 and 3 identified a potential tool that can be used to accomplish the desired information sharing—Argonne National Laboratory's *NGInsight* Tool.[315] The tool makes it possible to identify the potential impact of weather or other critical events on overall natural gas supply.[316] Additionally, through machine learning informed by electric wholesale market participant input, *NGInsight* can rank the severity of natural gas pipeline notifications posted on EBBs to further enhance situational awareness.[317] For more information about how information sharing could be used to improve natural gas and grid system reliability, see Recommendation 4(b).

315 According to the Forum Report, NGInsight "collects EBB data and provides near real-time assimilation of information from approximately 75 percent of interstate and offshore natural gas pipelines, creating a national-level view of natural gas system situational awareness. Argonne National Laboratory Presentation – June 29, 2023 (Page 3, Argonne National Laboratory) (NAESB Report n.101). The data collected and displayed by the tool include information that identifies unsubscribed capacity, total scheduled quantity as a function of state, county, and/or pipeline as well as critical and non-critical notices, and the tool has the ability to layer other relevant datasets, such as utility service territories and weather alerts. Argonne National Laboratory Presentation – June 29, 2023 (Pages 3 – 4, Argonne National Laboratory) (NAESB Report n.102). NAESB Report Recommendation 2 noted that the Commission should "take steps to facilitate the expansion of the Argonne National Laboratory NGInsight tool, with funding from a federal governmental agency, such as the Department of Energy," while acknowledging the importance of security and market protections. NAESB Report at 21. This recommendation received support from 46 percent of the Wholesale Gas Market and 85 percent of the Wholesale Electric Market, as those terms are defined in the NAESB Report. Id. at 19-20.

316 Argonne National Laboratory Presentation – June 29, 2023 (Pages 3 – 6, Argonne National Laboratory) (NAESB Report n. 103).

317 Argonne National Laboratory Presentation – June 29, 2023 (Page 5, Argonne National Laboratory) (NAESB Report n. 104).

Recommendation 6: The Commission should consider whether to order Commission-jurisdictional natural gas entities to provide the Commission with one-time reports describing their roles in assessing and responding to natural gas supply and transportation vulnerabilities in extreme cold weather events.

As discussed in Section IV.C.4 above, freezing was a significant cause of pipeline equipment outages that caused some flow reduction, and the primary cause of pipeline equipment outages directly affecting shippers. Recommendation 6 is based in part on the various preparations for Winter Storm Elliott that pipelines shared with the Team. The Team surveyed a total of 15 interstate pipelines within the Event Area. Pipelines shared common practices in the planning and preparation for Winter Storm Elliott, specifically in areas such as proactively monitoring weather forecasts, manning key facilities, issuing critical notices, increasing line pack, and putting storage facilities on stand-by. However, these measures were assigned different priorities by different pipelines and implemented in different ways depending on the location, design, and size of each individual pipeline system. For example, some pipelines issued pre-emptive Operational Flow Orders (OFOs) prior to the start of the Event, whereas others issued generic notices alerting customers of extreme conditions. Internal (gas control, operations, scheduling, storage, commercial personnel) and external (RTOs, customers, utilities) stakeholder meetings also occurred with varying degrees of frequency among the pipelines. These meetings aired concerns about reliability issues, nominations, and scheduling as applicable to each pipeline's system.

If the Commission were to proceed with an order regarding the one-time reports, it could consider asking the FERC-jurisdictional entities to analyze their experiences in Winter Storms Uri and Elliott, and to address the entities' plan(s) for mitigating identified vulnerabilities. The collected data would allow the Commission to determine if it could take additional actions within its jurisdiction to address the risk that extreme cold weather events pose to the natural gas infrastructure system. If a FERC-jurisdictional gas entity were to submit a one-time report, it could seek CEII treatment or other protections available under the Commission's regulations, as appropriate.

Recommendation 7: An independent research group (e.g., selected National Laboratories from the Department of Energy), should perform one or more studies to analyze whether additional natural gas infrastructure, including interstate pipelines and storage, is needed to support the reliability of the electric grid and meet the needs of natural gas Local Distribution Companies. The study should include information about the cost of the infrastructure buildout. (Initiate study Q1, 2024)

In light of the Commission's role in reviewing interstate natural gas projects and other gas infrastructure (e.g., interstate natural gas storage facilities), as well as the need for sophisticated modeling, the Team recommends that an independent entity with robust modeling capabilities undertake the study. It would be ideal if one of the DOE National Laboratories would conduct the study, as they have the technical expertise and have invested in modeling of the U.S. natural gas and electric infrastructure. However, if that is not feasible, the National Academies of Science and Engineering, and the Electric Power Research Institute have also performed sophisticated grid-related studies in the past, as well as studies of natural gas issues.

The purpose of the study would be to identify additional natural gas infrastructure needs, if any, needed to ensure the continued reliability of the electric and natural gas systems, and the preferred locations of such infrastructure, if applicable, including pipeline infrastructure, natural gas storage, and other supporting systems. The study should consider the needs in light of coincident peaks of LDC demand for natural gas as well as demand from natural gas-fired generation during periods of prolonged, abnormally cold weather. The study should analyze needs on a regional basis and consider current as well as forecast future needs, in light of our evolving and interdependent energy

system. The study should consider whether there will be adequate natural gas infrastructure to support new gas usage patterns by gas-fired generation to manage the increased penetration of variable, renewable energy resources and thermal resource retirements, including increased ramping requirements and seasonal resource availability, among others. In addition, the study should consider natural gas infrastructure needs during anticipated, extended extreme heat and cold weather periods. It should also consider recent patterns of natural gas production declines during extreme cold weather (e.g., Winter Storm Uri, Winter Storm Elliott).

The study should include information about the cost of the infrastructure buildout. In making this recommendation, the Team notes that two of the North American Energy Standards Board Report recommendations for additional studies concerned the cost of natural gas infrastructure, for storage and for infrastructure to provide additional firm transportation capacity.[318]

318 Recommendation 18 sought a study about "whether market-incentivized investments in strategic natural gas storage facilities are sufficient to address natural gas supply shortfalls during extreme cold weather events, and if the level of investment is sufficient to preserve such facilities for use during extreme cold weather events. The study should also explore whether public sources of funding are needed for investment to secure sufficient storage." Recommendation 19 asked for a study of "whether additional financial incentives for the natural gas infrastructure system, including infrastructure to provide additional firm transportation capacity, would help to address natural gas supply shortfalls during such events [like Uri], and further support the Bulk Electric System's performance during extreme cold weather events." NAESB Report at 63-64.

D. Electric Grid Operations Cold Weather Reliability

Recommendation 8: Balancing Authorities should assess whether new processes or changes to existing ones—such as multi-day risk assessment processes or advance or multi-day reliability commitments—are needed to address anticipated capacity shortages or transmission system-related reliability problems during well-forecast extreme cold weather events. In performing risk assessments or supporting multi-day reliability commitment, BAs should consider the following:

A. how to account for uncertainty in load forecasts, generating unit fuel availability and extreme cold weather availability, and the effects of extreme cold weather across multiple regions; and

B. committing generating units prior to the onset of extreme cold weather, including a means of ensuring units are compensated for their commitment costs (including the costs of obtaining fuel), even if no dispatch occurs. (Q4, 2023)

The five extreme cold weather events have revealed a set of uncertainty risks that have challenged BAs as they plan for and operate during these events. In every extreme cold weather event, BAs have faced unexpectedly high amounts of unplanned generating unit outages.[319] In four of the last five events, short-term load forecasts were lower than actual for some BAs, and in three of the last five events (the only ones that examined the issue) significant reductions in natural gas production occurred. Many natural gas-fired generating units indicated during the Event that they were unavailable because they did not have advance arrangements for natural gas fuel supply for the hours they were committed to operate, and by the time they were notified for commitment, natural gas supplies were unavailable. All of the BAs thought that they had sufficient reserves arranged to meet their forecast peak electricity demands, until they were faced with escalating unplanned outages and increased customer demand that, for most, exceeded their load forecasts. By the time that these trends were apparent, the BAs had limited flexibility, leading many of them to declare Energy Emergencies and some to shed firm customer load.

These scenarios should no longer be unexpected. BAs need to evaluate the uncertainty or risk they face when preparing for extreme cold weather events that have been forecast well in advance (and all the most serious extreme cold weather events have been forecast many days in advance) to reduce their reliability risk during these events. Evaluating risk or uncertainty, which some BAs already combine with a multi-day reliability unit commitment process, in advance of and during extreme cold weather events will best enable BAs to prepare to meet their commitments and maintain system reliability.

SPP's experience during the Event provides one example of how a BA can combine the evaluation of risk or uncertainty with multi-day unit commitment.[320] According to SPP's Winter Storm Elliott Report, "going into [Winter Storm Elliott] SPP had to anticipate uncertainty in the following areas:

- Uncertainty of accurate load forecasting for December 23, December 24, December 25 due to wind chill.
- Uncertainty if the forecast for high wind levels would hold, and to what extent wind farms would be shut down or de-rated for low ambient temperatures.
- Uncertainty if the gas resources SPP committed would be able to purchase gas.
- Uncertainty if resources SPP committed would be timely due to preheat and start-up.[321]
- Uncertainty of how many resources would trip because of freezing of equipment resulting from low temperatures and high wind chill conditions.
- Uncertainty of how much congestion SPP would

319 *See* Figure 5, which reveals similarities among past extreme cold weather events.

320 This is one example. Other BAs may have their own methods of evaluating uncertainty and/or multi-day unit commitment.

321 SPP was concerned about all gas resources committed, not just those committed in the day-ahead.

experience that required re-dispatch of resources that could lock up headroom of resources.
- Uncertainty if the Missouri River would develop ice blocks preventing adequate river flow and potentially limit hydro generation and cooling water availability."[322]

SPP's Elliott experience revealed the importance of remaining flexible when evaluating uncertainty in extreme cold weather events. For example, the Missouri River freezing issue developed during the Event. During the Event, SPP's Uncertainty Response Team, [323] which helps to identify and address upcoming capacity challenges given forecast system conditions, recommended the commitment of long-lead-time generation, which SPP then committed using its Multi-Day Reliability Assessment process.[324] On December 21, SPP committed generation for December 22 and 23, to help with capacity, deliverability concerns and uncertainty; on December 22, it committed generation for Christmas Eve, and on December 23, for Christmas Day.[325]

SPP also "committed several GW of primarily gas generation ahead of time for Dec[ember] 22 through . . . 25, to cover normal long-lead time units as well as help ensure there was a sufficient amount of gas procured to cover the forecast obligations (a portion of short-lead-time gas units),"[326] through its Multi-Day Reliability Assessment process. This advanced commitment process is particularly helpful if the extreme weather event is expected to occur over the weekend, on a Monday, or on a Tuesday following a holiday weekend, given the limited natural gas market liquidity during these periods. SPP also committed natural gas units that were not long-lead units early so that they could obtain natural gas in advance of Winter Storm Uri and believes that it enabled more units to operate during the worst of the Winter Storm Uri event.[327]

The Team notes that the North American Energy Standards Board Report recommended that Independent System Operators/Regional Transmission Organizations "adopt multiday unit commitment processes to better enable the industry to prepare for and provide reliable service during events in which weather is forecast to cause demand to rise sharply for both electricity and natural gas," and it received 90 percent support from both the gas and electric wholesale quadrants.[328] Additionally, the PJM Report recommended that it "[e]valuate the current multi-day commitment process for use during expected critical

322 SPP Report at 6-7.

323 Daily evaluations flag uncertainty risks for the next seven days. The URT applies uncertainty factors for load forecast, wind forecast and resource (generation outage) error. The URT puts historical data into "bins" for wind forecast error, load forecast error, and generation outage error, analyzes what weather conditions are associated with particular ranges of error and then applies uncertainty error percentages to available offline and online capacity for every hour for the next seven days. This refined "scaling" process results in, for example, instead of predicting the possibility of 500 MW of error on a particular day, predicting 100 MW of error for hour 0700, 200 MW of error for hour 1900, and so on. SPP analyzes for coincidental error—the percentage chance of all of the errors happening at the same time. They look at 50/50, 90/10, and 99.5 percent likely scenarios, all of which are shared with operators. If operators see insufficiency all the way down to the 50/50 scenario they know it is more likely that the system will experience insufficient resources that day. Larger potential capacity gaps are found at the lesser percentile, and smaller gaps are more common, more likely to be found in the 50/50 scenario (equally likely to happen or not happen). SPP uses the uncertainty evaluations produced by the URT to help coordinate how much generation will be allowed to be on planned outages, to commit long-lead-time units that may otherwise become unavailable (any unit for which the minimum start-up or down time is such that the unit cannot be committed in the day-ahead market, or has another start-up availability limiting circumstance), and to prepare mitigation plans for scenarios where analysis shows a risk of SPP's capacity being inadequate to meet its obligations.

324 The URT recommends units when an uncertainty forecast merits the need for such units and such units may become unavailable if not acted upon.

325 SPP Report at 7.

326 SPP Report at 7. SPP has filed proposed tariff revisions to clarify the ability to commit short-lead-time-units so that they can obtain natural gas, among other proposed revisions.

327 In Uri, SPP needed all available units online. In Elliott, SPP ended up needing much more natural gas-fired capacity than the short-lead-time gas units they had committed early.

328 NAESB Report at 2, 5 (Recommendation 9).

high demand periods so as to analyze the costs and benefits of providing greater certainty of fuel supply procurement through the critical period, with a focus on weekends when the gas commodity market can be less liquid."[329]

Pre-operational warming is a practice that has been recommended since the 2011 Report to avoid unplanned freezing-related outages.[330] One way to reduce the risk of unplanned outages is for BAs use their evaluation of the uncertainty to manually commit a portion of their generating units to operate the units before the coldest temperatures arrive, even if the units are not needed to serve load at that point. Doing so will help mitigate the extra challenge created by cold-starting a unit in extreme cold conditions. If a unit fails *during* the advanced commitment, the BA will be able to identify and potentially address generation shortfalls before the extreme weather arrives. During extreme cold weather events like Winter Storms Elliott and Uri, it is not uncommon for BAs to rely on generating units that rarely operate. PJM's experience with units that had not run in four weeks or more is consistent with committing some generation before the coldest temperatures arrive, in an effort to make more generation available when it is most needed. PJM noted that 70.5 percent of units that had not run in four weeks or more before the Event experienced an outage, while only 45.5 percent of units that had run within four weeks did so, a 25 percent improvement. Both testing and manually committing generation before the coldest temperatures arrive can increase the likelihood that the unit will be available to run when needed in real time.[331]

Recommendation 9: Balancing Authorities should improve their short-term load forecasts for extreme cold weather periods by implementing the lessons and practices identified below and sharing newly identified effective practices with peer BAs for continuous improvement. (Implement sharing Q4, 2023)

In four of the last five extreme cold weather events, short-term load forecasts, or forecasts of peak electricity demand, were lower than the actual peak electricity demand, for some BAs in the Core Event Area. Accurate short-term load forecasts in advance of extreme cold weather events enable BAs to commit long-lead-time resources, plan for additional imports that may be needed to meet reserves, and notify customers in advance of potential emergency conditions, to achieve greater awareness and participation if voluntary load reduction is needed. Most BAs in the Event under-forecast load in their 5-day, 4-day, 3-day, 2-day and day-ahead load forecasts, and the Team encourages them to implement and share effective practices for improving short-term load forecasts. However, accurate load forecasts alone could not have overcome the massive volume of unplanned generating unit outages experienced by many of the BAs.

Two key practices for improving short range load forecasts are (1) understanding the drivers of the BAs' extreme cold weather load and (2) studying the drivers of BAs' under-forecast load for past events. The Team found that some entities understood the drivers of their cold weather load far better than others, and those entities performed better on their short-term load forecasts. The use of distribution-level smart meter data, combined with Artificial Intelligence (AI)-powered predictive intelligence, is a promising new approach for understanding load drivers.[332] Some entities used third-party load forecast services and participated in the load forecast process in varying degrees. Entities that were more engaged in and better understood the load

329 *See* PJM Report Recommendation 9, at 4.

330 2011 Report at 60-61. During Winter Storm Uri, units reported pre-operational warming in response to an ERCOT directive. *See* 2021 Report at 53.

331 PJM recommended, but did not require, generating units to perform a "Generation Resource Operational Exercise" before the winter. *See* PJM Report at 10. These units are compensated as price takers, like any other self-scheduled units.

332 This service provides insights to the grid entity (e.g. how much of the load in a particular area is driven by heating and/or cooling, whether behind-the-meter assets may be located within its footprint and their hourly demand), which helps to better predict volatility in demand, both as to timing and magnitude. The third-party provider used by the entities was Innowatts (https://www.innowatts.com/).

forecast process, instead of treating it as a "black box" service, performed somewhat better.

Balancing Authorities identified multiple factors that played a role in underestimating short-term load as compared to actual load. For example, they noted that load forecasts were affected by a mismatch between the temperature used in the forecast versus the actual temperatures,[333] high winds,[334] blizzard conditions, and struggles to predict the exact timing of when the coldest weather would arrive. Several entities also found that they did not experience a normal load profile with a deep valley during the night—the drop in temperatures/extreme cold temperatures meant that the "valleys" were abnormally high. Another important element was identifying the presence of resistive heating in an entity's load.

The Team recognizes that some entities and regions already engage in sharing effective practices and encourages them to continue. But based on the wide variety the Team observed in load forecasting practices within the Event Area, the Team believes that sharing of effective practices can be enhanced, with the aim of improving the accuracy of short-term load forecasts. For more information on improving short-term load forecasts, see Section IV.D.1 and Figures 19-21, above.

Recommendation 10: Resource Planners and entities that serve load should sponsor joint-regional reliability assessments of electric grid conditions that could occur during extreme cold weather events.[335] (Initiate assessments, Q4, 2024)

Recommendation 10 focuses on improvements that entities responsible for planning and/or acquiring capacity and energy resources to serve firm load can make to help address the risk of firm load shed during future extreme cold weather events. As described in Section III.B, several Balancing Authorities in advance of winter 2022-2023 and during the Event relied on the availability of external generation resources (i.e., in the form of purchase power/import power schedules and emergency energy) to serve their firm load. When the Event impacted all of the adjacent BAs, resulting in curtailment of imports, that curtailment contributed to the need for firm load shed within the BAs that had relied upon imports or the possibility of emergency energy.

The types of extreme cold weather events to be studied are those that, like Winter Storms Elliott and Uri, simultaneously impact multiple operating areas and Regional Entity footprints.[336] The assessments should be conducted jointly, involving multiple planning regions, multiple Regional Entities, and/or multiple BA footprints within regions. They should consider the use of probabilistic approaches in accounting for uncertainties in availability of external generation resources, potential for simultaneous winter peak load conditions in multiple footprints, and uncertainties in deliverability of generation resources (e.g., arrangements from

333 Some entities performed "backcasts" (calculating their load forecast with the actual temperatures) to isolate the effect of temperature from other factors.

334 "Air movement is an important cause of energy loss, particular[ly] in residential buildings, where infiltration [accidental introduction of outside air into a building, typically through cracks in the building] commonly causes between 30 and 75 [percent] of the total heat load in winter." Edward A. Arens and Philip B. Williams, The effect of Wind Energy consumption in buildings, (1977), https://www.aivc.org/sites/default/files/members_area/medias/pdf/Airbase/airbase_00017.pdf#:~:text=Wind%20flow%20around%20a%20building%20causes%20forced%20convection,layer%20itself%2C%20the%20wind-flow%20patterns%20around%20the%20building%2C185.

335 Forms of sponsorship could include, but not be limited to, providing input or advice on the development of interregional planning models, extreme cold weather study cases and scenarios, and/or through support of collaborative planning activities.

336 The February 2021 Winter Storm Uri impacted the ERCOT Interconnection, and MISO and SPP footprints in the Eastern Interconnection (TRE, MRO, and SERC Regional Entity footprints); the January 2018 cold weather bulk electric system event impacted, MISO, SPP, TVA, and Southern in the Eastern Interconnection (MRO and SERC Regional Entity footprints); the 2014 Polar Vortex impacted both the Eastern and ERCOT Interconnections (MRO, RF, NPCC, SERC, and TRE Regional Entity footprints), and the February 2011 event impacted ERCOT and the Western Interconnection.

generation resources external to a load serving area).[337]

In accounting for generation resource unavailability, winter assessments typically account for generating unit scheduled/planned outages expected to occur during winter peak load timeframes, as well as an estimated amount of unplanned generation outages. The projected available resource capacity is used to calculate projected resource reserves above the 50/50 and 90/10 winter peak load forecast, or whether there will be an expected shortfall. In estimating the impact of unplanned generation outages, resource planners and entities serving firm load should consider the likelihood of higher levels of unplanned generation outages across multiple regions during extreme cold weather. As an example, NERC uses operational risk analysis as part of its seasonal assessment process, which provides an approach for determining reliability impacts from certain scenarios and understanding how various factors affecting resources and demand can combine to impact overall resource adequacy. Adjustments are applied cumulatively to anticipated capacity—such as reductions for typical generation outages/derates and additions that represent the quantified capacity from operational measures, if any, that are available during scarcity conditions (e.g., emergency maximum generation available). The effects from low-probability events are also considered.

In accounting for risks that peak load conditions may have on serving firm load, planners should consider that winter peak electricity demands during the Event in the BA footprints located from the Central Plains to the Atlantic Seaboard all occurred within a 36-hour period. A multi-area concurrent peak load scenario, coupled with many thousands of MW of unplanned generation outage scenario, compounds the risk of unavailable external generation resources or unavailability of purchase power for import, regardless of intraregional or interregional transfer capability. If a BA is experiencing a worsening capacity and energy emergency condition, it may reach a point when it must curtail all exports unless those exports are backed by installed capacity that is not already counted towards installed capacity for the BA's native load. Purchasing-selling entities[338] should understand the answer to the question "How firm is my firm power purchase?" in advance of future extreme cold weather periods.

In accounting for risks in resource deliverability, winter case extreme scenarios can be performed to determine potential constraints or limitations. For example, as part of its winter assessment, SERC performed a powerflow case simulating a MISO to SERC-East 6,000 MW power transfer to study the impact of a west-to-east transfer during peak conditions. There are related initiatives underway which can be leveraged to ultimately assist entities that serve load to evaluate risks to serving firm load during extreme cold weather periods. NERC Standards development project 2022-03 – Energy Assurance with Energy-Constrained Resources, proposes that entities (most likely BAs and RCs) conduct energy reliability assessments, and when predefined criteria are not met (criteria need not be defined in Standard), the responsible entity shall develop Corrective Action Plans, operating plans, or other mitigating actions. In addition, the Commission recently issued Order No. 896, which directs, among other things, the development of extreme cold weather benchmark events that will form the basis for assessing system performance during extreme heat and cold weather events. The base case, representing system conditions under the relevant benchmark event, will be used to study the potential wide-area impacts of anticipated extreme cold weather events.

337 The 2018 Report recommended that Planning Coordinators and Transmission Planners should jointly develop and study more-extreme condition scenarios with modeling that includes removing generation units entirely to represent actual generation outages (especially outages known to occur during severe weather), versus scaling of generating unit outputs, and modeling system loads so that the study accurately tests the system for the extreme conditions being studied. 2018 Report at 94-95 (Recommendation 7).

338 The entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchasing-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities. *See* NERC Glossary of Terms, at https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

Recommendation 11: A team of subject-matter experts (e.g., the Eastern Interconnection Planning Collaborative) should conduct a study of the state of the Eastern Interconnection during the evening of December 23 and early morning hours of December 24, to examine dynamic stability and system inertia, and determine how close the interconnection may have been to triggering an underfrequency load shed event. (Initiate study, Q1, 2024)

As seen in Winter Storm Uri, when the power grid suffers an extreme loss of generation resources during periods of high system demands, the grid becomes more vulnerable to a complete blackout. In that event, ERCOT operators were forced to shed larger and larger blocks of firm load, within minutes of one another, to restore frequency and avoid a blackout of the ERCOT Interconnection.[339] As discussed in Section III, and demonstrated by Figure 39, on late December 23 and early December 24, the Core Event Area and the Eastern Interconnection were experiencing their highest winter electricity demands. Figure 37 shows that, at the same time, generating unit outages were climbing. As a result, there were times on the evening of December 23 and the morning of December 24 when the potential responsive operating capacity, which included online and any offline capacity, was within 15,000 to 20,000 MW of the combined loads at the worst points. While that may appear to be an adequate level of reserves, spread over the Eastern Interconnection, and at a time when the risk of additional generating outages was high, the Team is concerned that it may not have provided a sufficient safety net.

During the same period, Eastern Interconnection frequency excursions were common, dropping below 59.95 Hz (the lower band limit for maintaining frequency) four times and dropping as low as 59.936 Hz at approximately 4:25 a.m. Based on these findings, the Team is concerned that the Eastern Interconnection could have been at risk of instability during the period of high winter electricity demands and rising generating unit outages.

The Team believes that the Eastern Interconnection Planning Collaborative,[340] in coordination with NERC, Regional Entity and FERC staff, could assess next-contingency/single-point of failure contingency conditions to assess dynamic stability of the Interconnection through modeling and assessing the Bulk Electric System conditions during the Event. Further study(s) of the Eastern Interconnection during the critical period of the evening of December 23 and early morning December 24 can be used to identify actions needed to improve situational awareness and enhance operator tools and analysis capabilities. Real-time evaluation of such system conditions in the future could provide Reliability Coordinators with visibility of dynamic system conditions (e.g., through integration into its real-time contingency analysis processes), and assist in determining what actions may be taken (remedial analysis). Enhanced operator tools for situational awareness could prove especially useful when operators are faced with future resource mix changes that potentially expose the grid to more stability risks (e.g., as "high-inertia" coal units are retired and replaced by smaller intermittent resources with less inertia).

339 *See* 2021 Report, at 133.

340 The Eastern Interconnection Planning Collaborative (EIPC) is an organization that was formed in 2009 by NERC-registered Planning Coordinators in the Eastern Interconnection to perform coordinated interconnection-wide transmission analysis.

VI. CONCLUSION

This report provides a detailed assessment of the Event and the impact it had on portions of the Nation's energy infrastructure and service to consumers. The recommendations are designed to address matters identified in this report that call for improvement.

APPENDICES

APPENDIX A: INQUIRY JOINT TEAM MEMBERS

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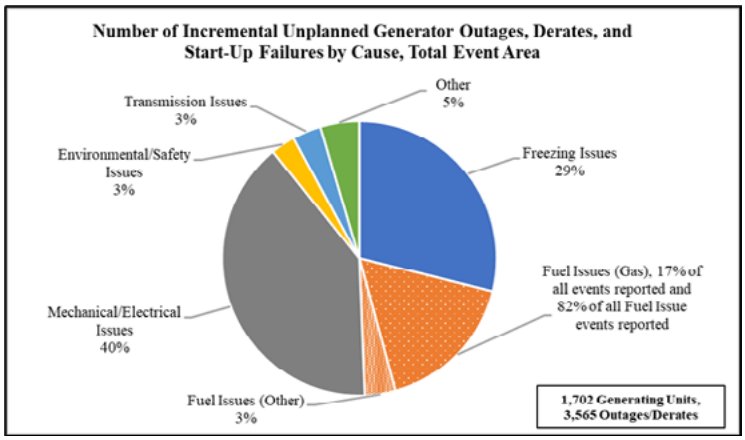
APPENDIX B: ACRONYMS USED IN THE REPORT

AC	Alternating Current
BA	Balancing Authority
BES	Bulk Electric System
CST	Central Standard Time
DC	Direct Current
DSM	Demand-Side Management
EEA	Energy Emergency Alert
EHV	Extra-High Voltage
EMS	Energy Management System
EOP	Emergency Operations Procedure
ERCOT	Electric Reliability Council of Texas
ERO	Electric Reliability Organization
FERC	Federal Energy Regulatory Commission
FRAC	Forward Reliability Assessment Commitment
GO	Generator Owner
GOP	Generator Operator
HVDC	High Voltage Direct Current
IROL	Interconnection Operating Reliability Limit
ISO	Independent System Operator
kV	Kilovolt
LBA	Local Balancing Authority
LMR	Load Modifying Resources
MSSC	Most Severe Single Contingency
MISO	Midcontinent Independent System Operator, Inc.
MRO	Midwest Reliability Organization
MVA	Megavolt-Ampere
MW	Megawatt
NERC	North American Electric Reliability Corporation
OPA	Operational Planning Analysis
PC	Planning Coordinator
PRC	Physical Responsive Capability
RC	Reliability Coordinator
RCIS	Reliability Coordinator Information System
RDT	Regional Directional Transfer
RDTL	Regional Directional Transfer Limit
RF	ReliabilityFirst Corporation
RTCA	Real-Time Contingency Analysis
RTO	Regional Transmission Organization
SCED	Security Constrained Economic Dispatch
SCRD	Security Constrained Redispatch
SERC	SERC Corporation
SeRC	Southeastern Reliability Coordinator
SOL	System Operating Limit
SPP	Southwest Power Pool, Inc.

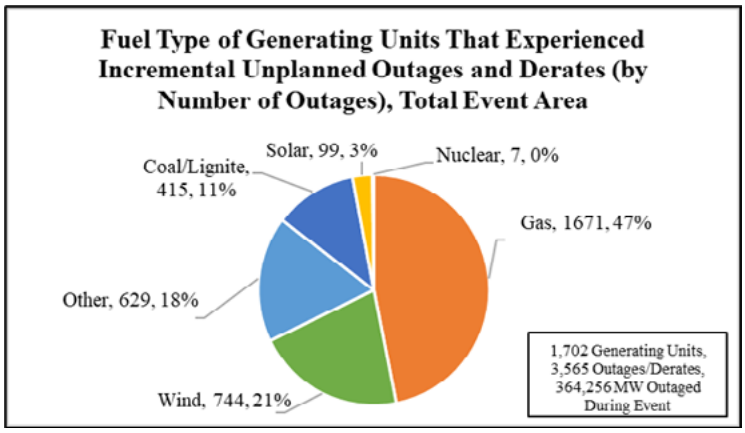
TDU	Transmission Dependent Utility
TLR	Transmission Loading Relief
TO	Transmission Owner
TOP	Transmission Operator
TP	Transmission Planner
TRE	Texas Regional Entity
TVA	Tennessee Valley Authority
UDS	Unit Dispatch System
VSA	Voltage Stability Analysis
WECC	Western Electricity Coordinating Council

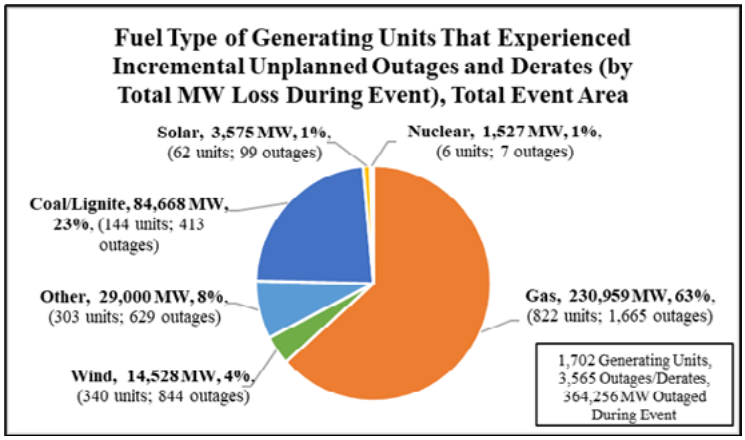
APPENDIX C: ADDITIONAL CHARTS AND FIGURES FOR UNPLANNED GENERATION OUTAGES DURING EVENT

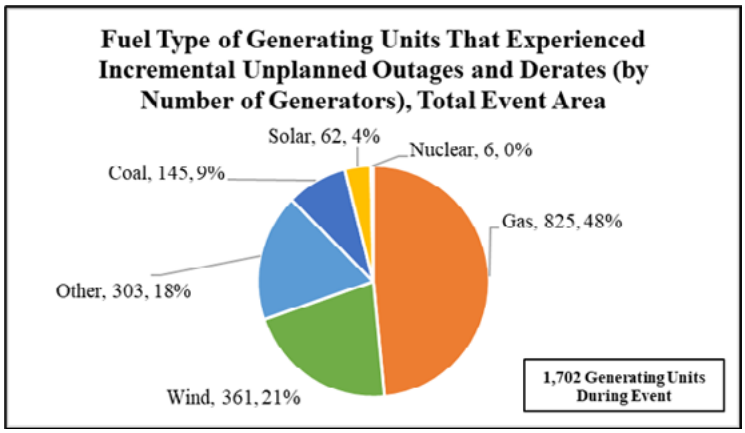
1. Number of Incremental Unplanned Generation Outages, Derates, and Failures to Start BY CAUSE, December 21-26, Total Event Area



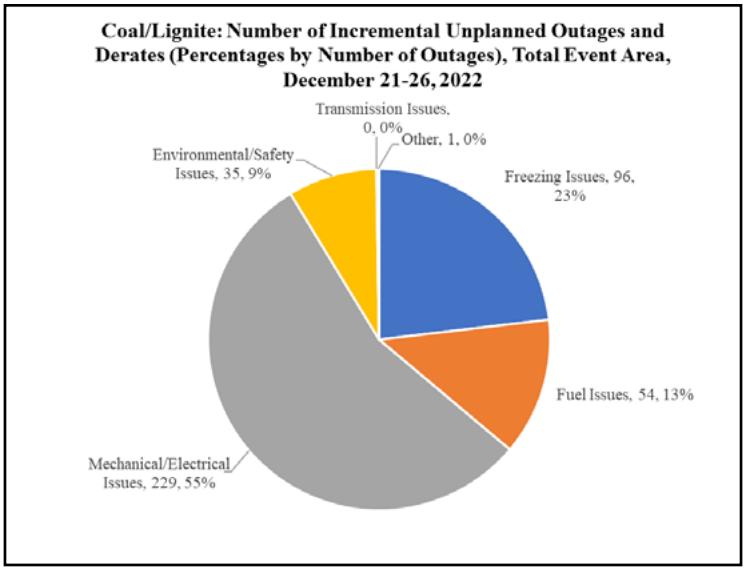
2. Unplanned Generation Outages by Fuel Type

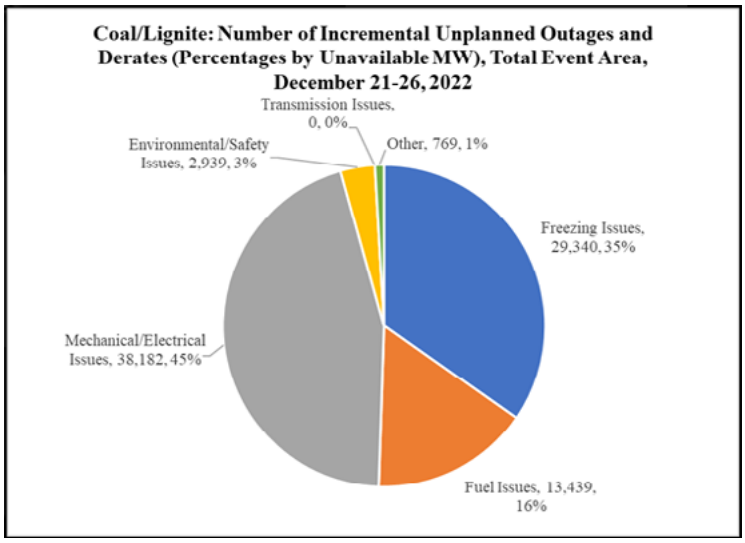


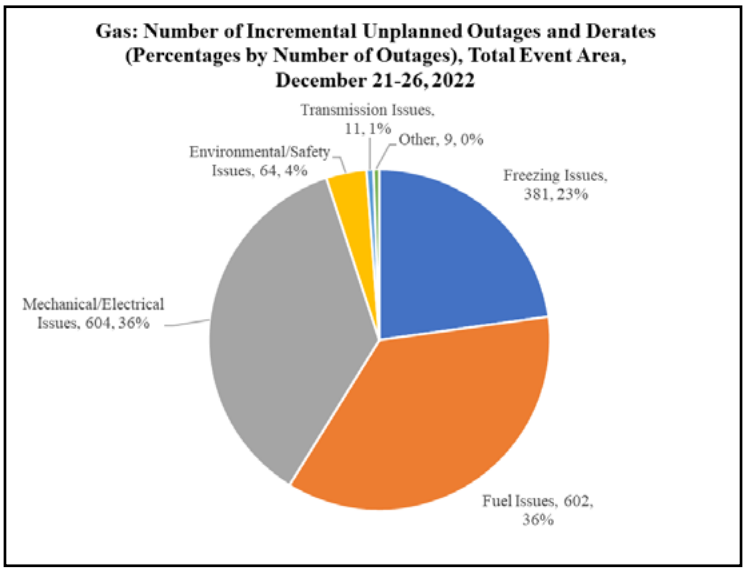


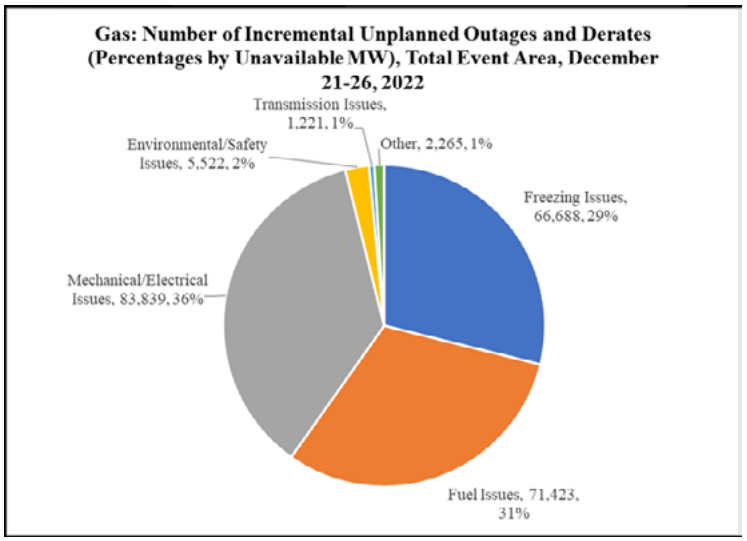


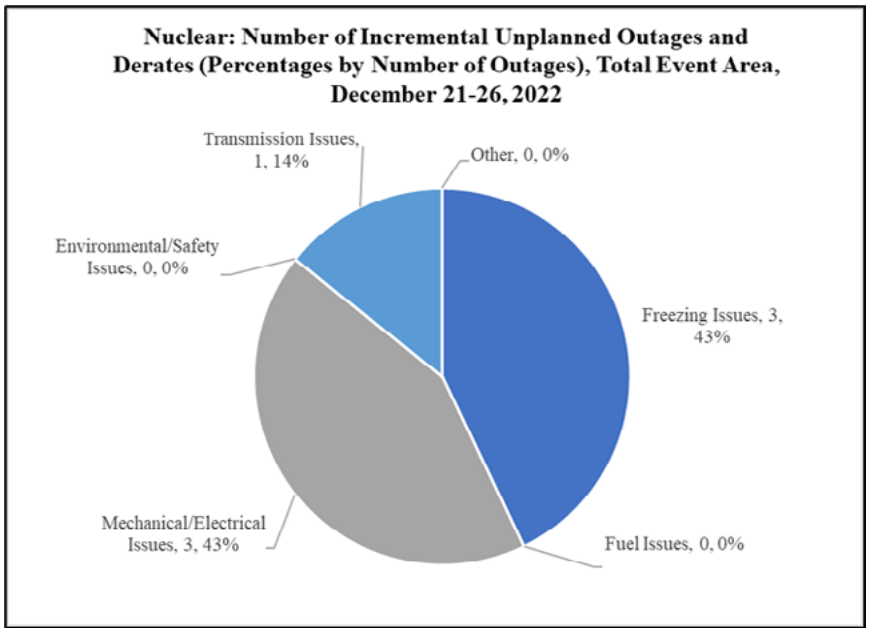
3. Causes of Unplanned Generation Outages, by Fuel Type of Generation

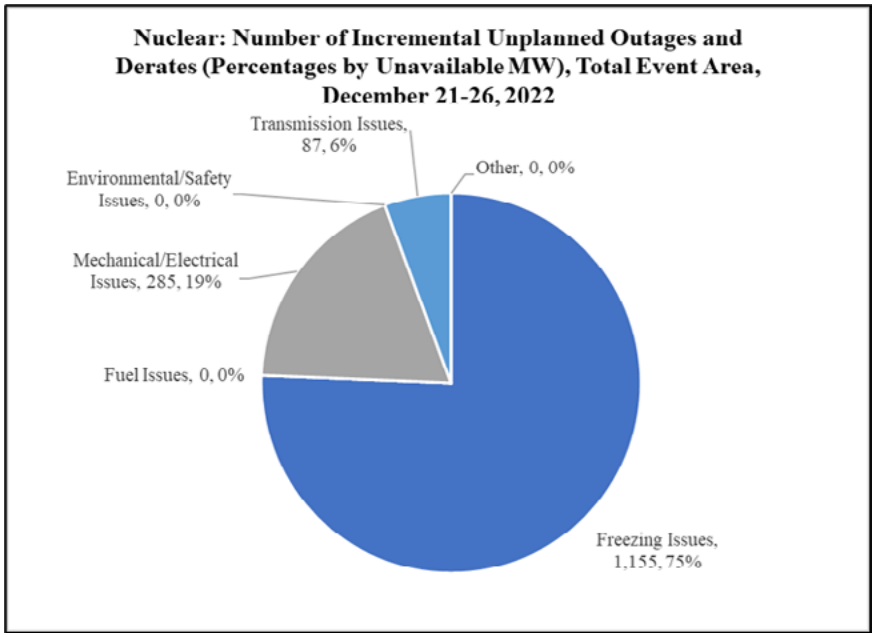


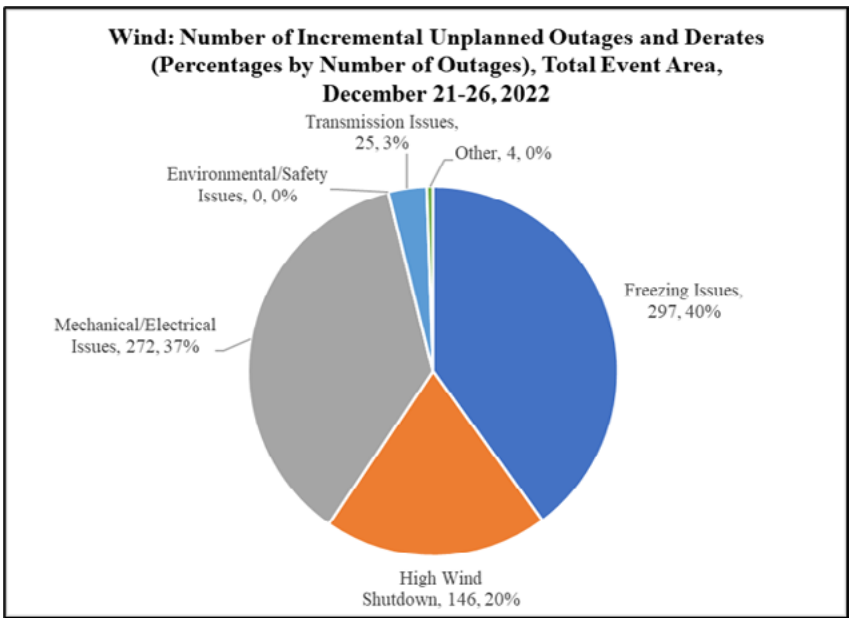


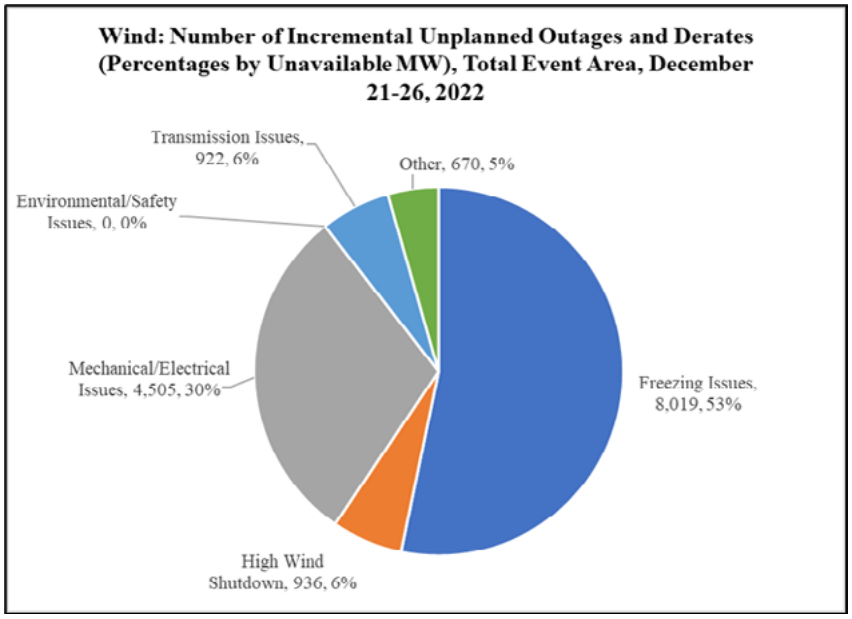

Gas: Number of Incremental Unplanned Outages and Derates (Percentages by Number of Outages), Total Event Area, December 21-26, 2022
Transmission Issues, 11, 1%
Other, 9, 0%
Environmental/Safety Issues, 64, 4%
Freezing Issues, 381, 23%
Mechanical/Electrical Issues, 604, 36%
Fuel Issues, 602, 36%

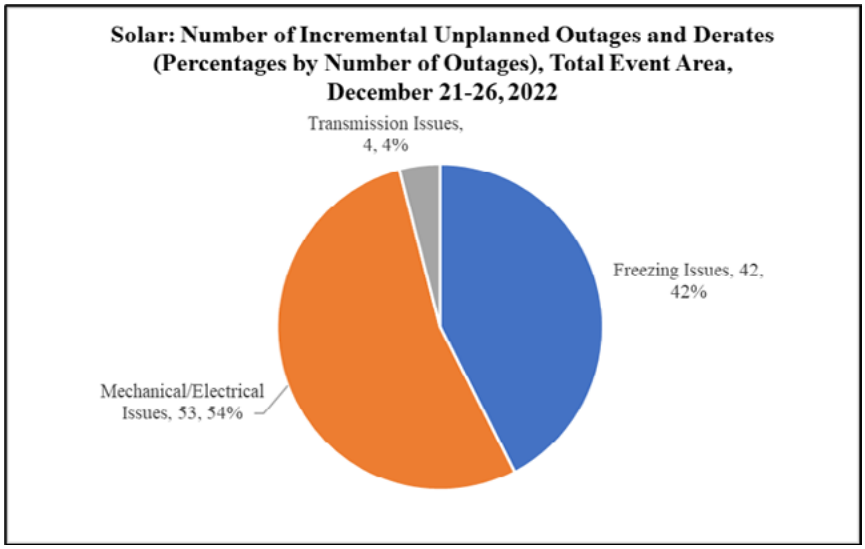

Gas: Number of Incremental Unplanned Outages and Derates (Percentages by Unavailable MW), Total Event Area, December 21-26, 2022
Transmission Issues, 1,221, 1%
Other, 2,265, 1%
Environmental/Safety Issues, 5,522, 2%
Freezing Issues, 66,688, 29%
Mechanical/Electrical Issues, 83,839, 36%
Fuel Issues, 71,423, 31%

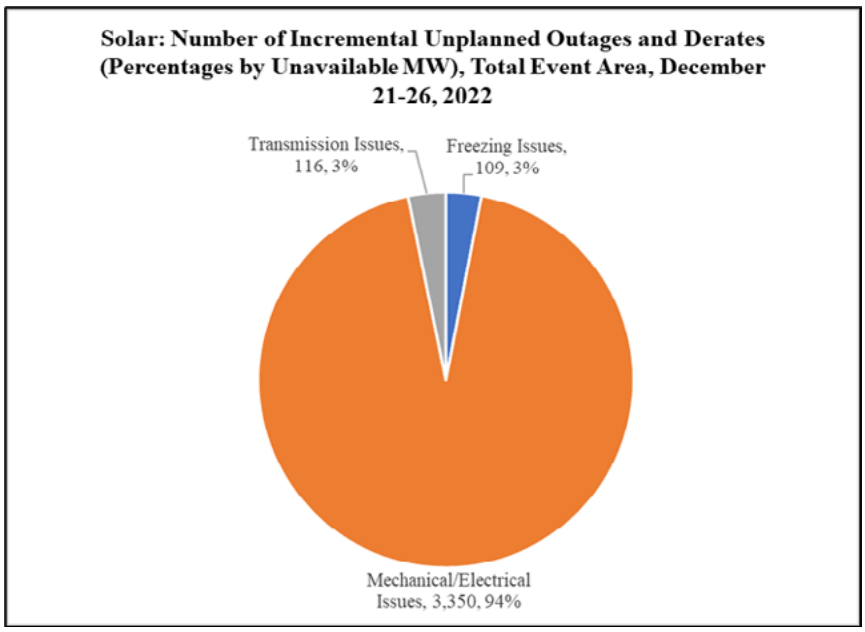

Nuclear: Number of Incremental Unplanned Outages and Derates (Percentages by Number of Outages), Total Event Area, December 21-26, 2022
Transmission Issues, 1, 14%
Other, 0, 0%
Environmental/Safety Issues, 0, 0%
Freezing Issues, 3, 43%
Mechanical/Electrical Issues, 3, 43%
Fuel Issues, 0, 0%

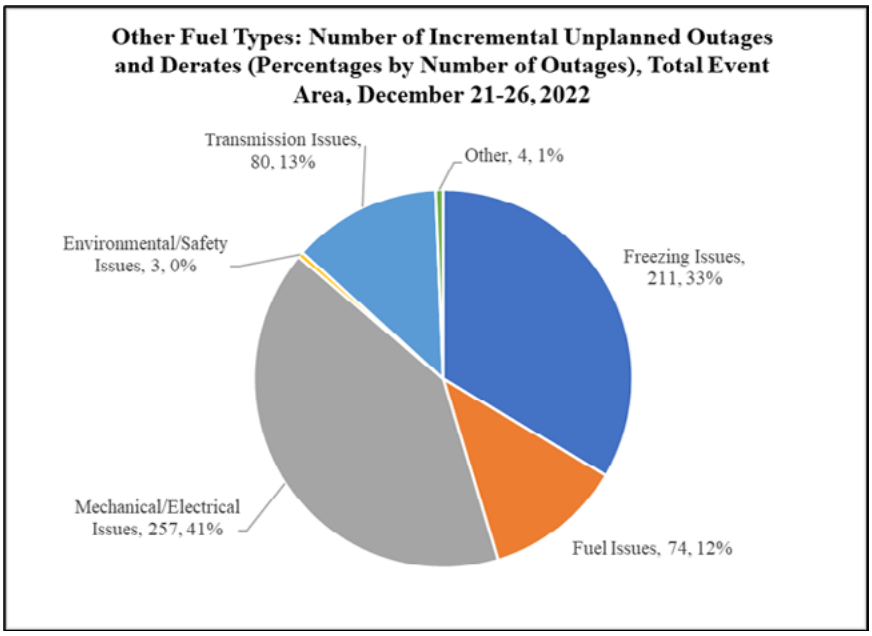

Nuclear: Number of Incremental Unplanned Outages and Derates (Percentages by Unavailable MW), Total Event Area, December 21-26, 2022
Transmission Issues, 87, 6%
Other, 0, 0%
Environmental/Safety Issues, 0, 0%
Mechanical/Electrical Issues, 285, 19%
Fuel Issues, 0, 0%
Freezing Issues, 1,155, 75%

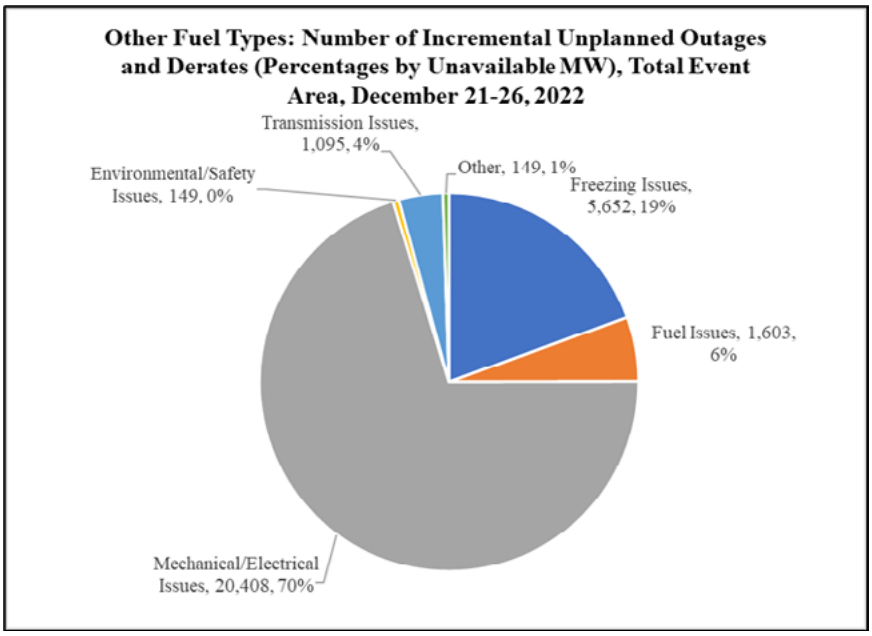

Wind: Number of Incremental Unplanned Outages and Derates (Percentages by Number of Outages), Total Event Area, December 21-26, 2022
Transmission Issues, 25, 3%
Other, 4, 0%
Environmental/Safety Issues, 0, 0%
Freezing Issues, 297, 40%
Mechanical/Electrical Issues, 272, 37%
High Wind Shutdown, 146, 20%


Wind: Number of Incremental Unplanned Outages and Derates (Percentages by Unavailable MW), Total Event Area, December 21-26, 2022
Transmission Issues, 922, 6%
Other, 670, 5%
Environmental/Safety Issues, 0, 0%
Freezing Issues, 8,019, 53%
Mechanical/Electrical Issues, 4,505, 30%
High Wind Shutdown, 936, 6%

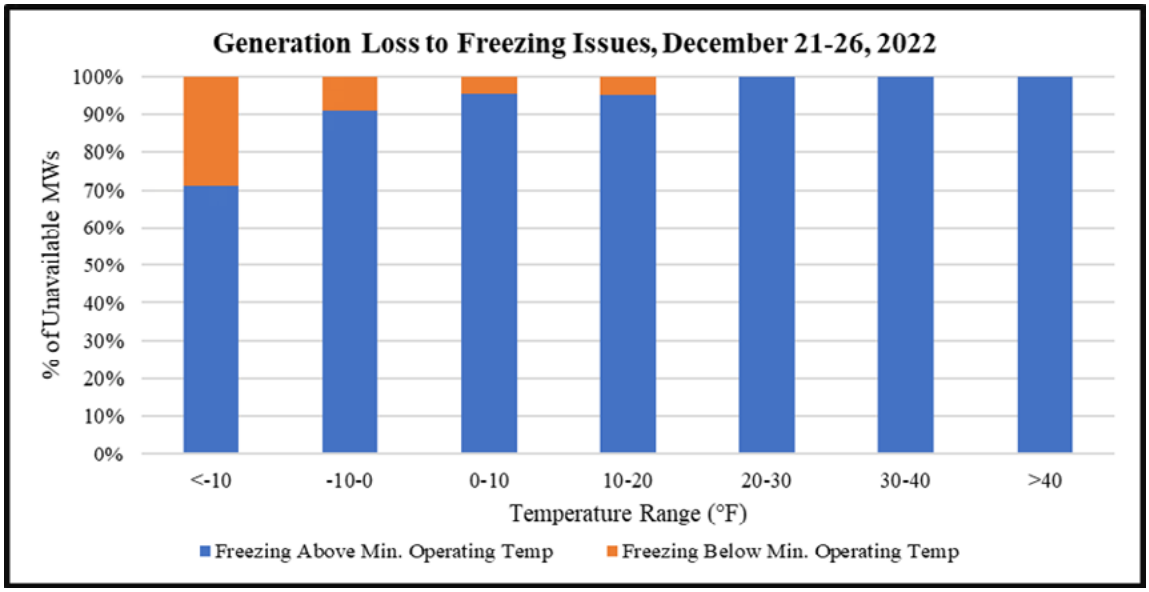

Solar: Number of Incremental Unplanned Outages and Derates (Percentages by Number of Outages), Total Event Area, December 21-26, 2022
Transmission Issues, 4, 4%
Freezing Issues, 42, 42%
Mechanical/Electrical Issues, 53, 54%

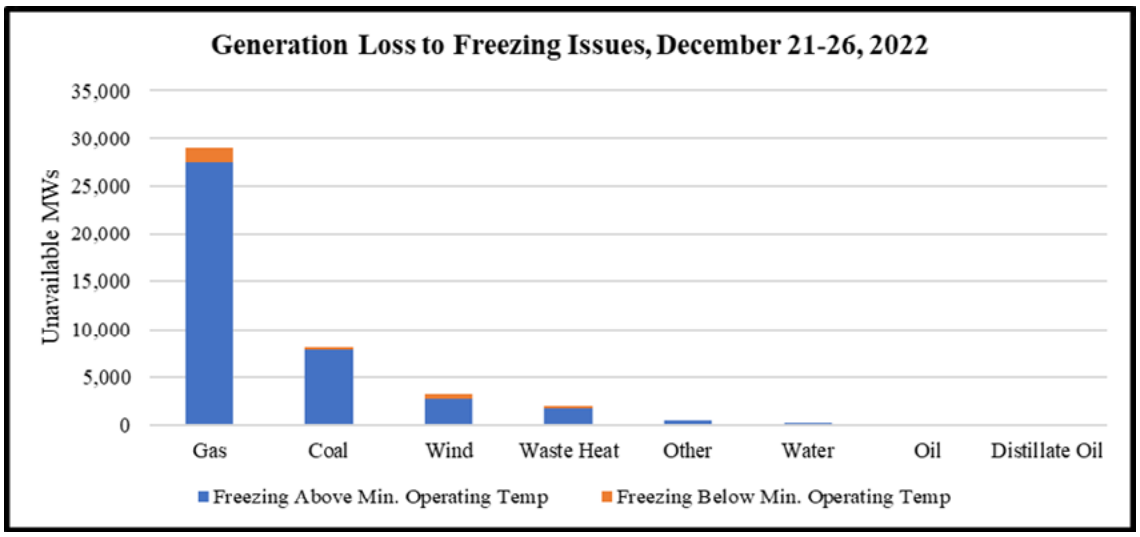

Solar: Number of Incremental Unplanned Outages and Derates (Percentages by Unavailable MW), Total Event Area, December 21-26, 2022
Transmission Issues, 116, 3%
Freezing Issues, 109, 3%
Mechanical/Electrical Issues, 3,350, 94%


Other Fuel Types: Number of Incremental Unplanned Outages and Derates (Percentages by Number of Outages), Total Event Area, December 21-26, 2022
Transmission Issues, 80, 13%
Other, 4, 1%
Environmental/Safety Issues, 3, 0%
Freezing Issues, 211, 33%
Mechanical/Electrical Issues, 257, 41%
Fuel Issues, 74, 12%

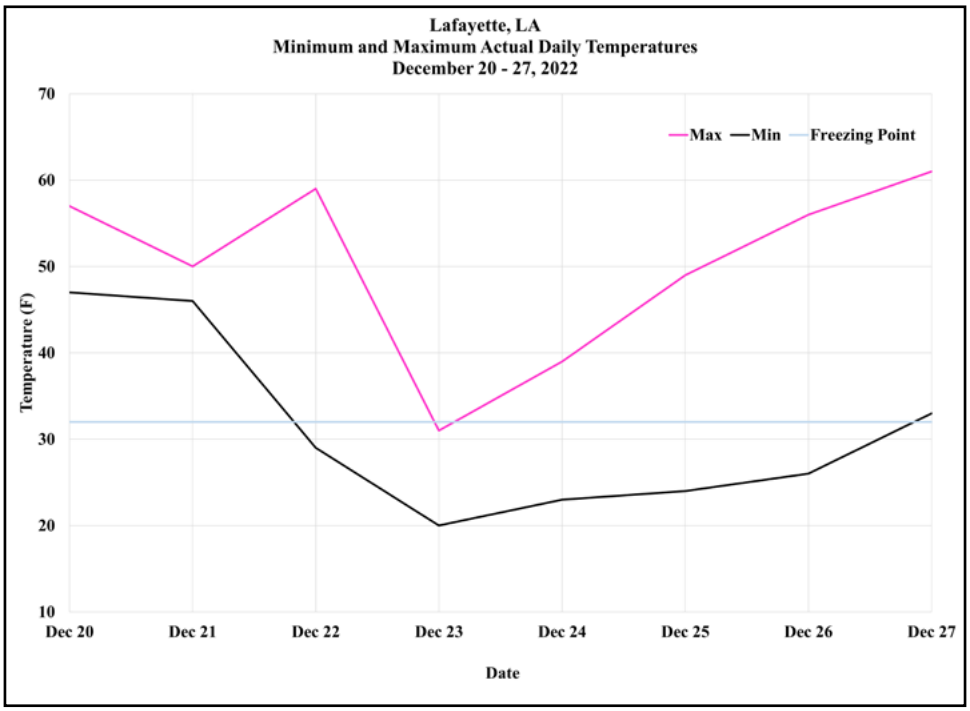

Other Fuel Types: Number of Incremental Unplanned Outages and Derates (Percentages by Unavailable MW), Total Event Area, December 21-26, 2022
Transmission Issues, 1,095, 4%
Other, 149, 1%
Environmental/Safety Issues, 149, 0%
Freezing Issues, 5,652, 19%
Fuel Issues, 1,603, 6%
Mechanical/Electrical Issues, 20,408, 70%

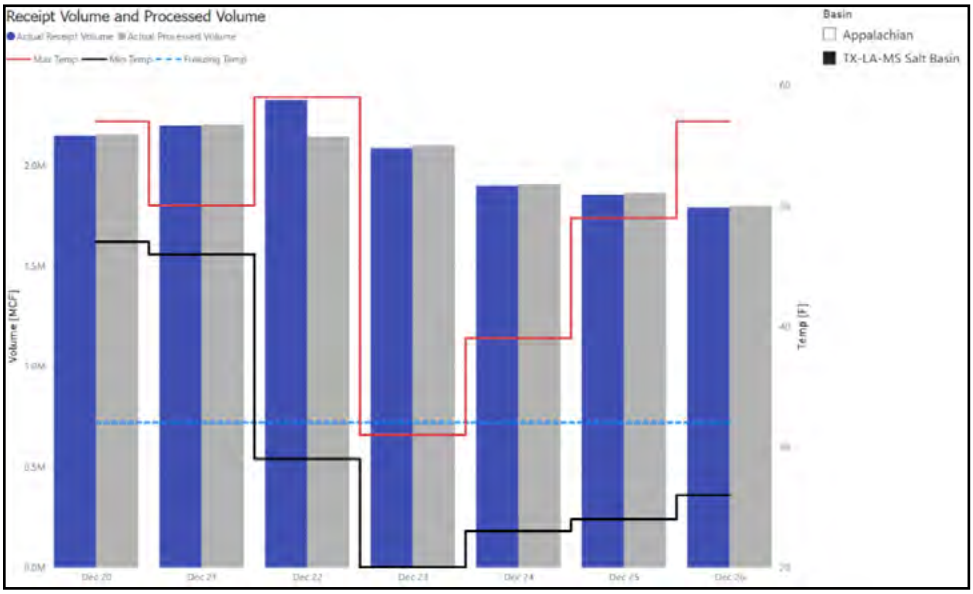
4. Cause: Freezing Issues – Additional Charts and Figures





APPENDIX D: NATURAL GAS PROCESSING DATA FOR TEXAS-LOUISIANA-MISSISSIPPI SALT BASIN

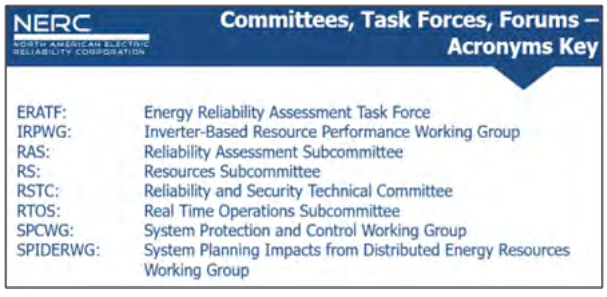




APPENDIX E: PROGRESS ON 2021 INQUIRY REPORT

FERC-NERC-Regional Entity Cold Weather Inquiry Reports - Recommendations Completion Tracking (as of October 2023)

URI Report Recommendations	URI / Percent Completed	Completion Notes		Elliott Report Recommendations (abbreviated text)
Extreme Cold Weather Event Prevention and Preparedness-Oriented Recommendations				
Rec. 1: Develop Reliability Standards for electric generator cold weather reliability	70%	Submitted Part of Ph. 2 Stds. to FERC by 11-1-23	Related to Elliott Rec.	Rec. 1: Robust implementation monitoring of freeze protection Standards to determine if reliability gaps exist
Rec. 2: Generator compensation opportunities for investments	(states)			---
Rec. 3: Generator winter readiness technical conference	100%	FERC/ERO conference held April 2022		---
Rec. 4: Generator freeze protection inspection and maintenance timing	20%	observation from Elliott event inquiry	Related to Elliott Rec.	Rec. 1: Seven recommendation sub-parts (1a-1g) for assuring freeze protection sufficiency
Rec. 5: Require natural gas facility cold weather preparedness plans and measures	20%	Now Required in Texas	Related to Elliott Rec.	Rec. 4a: Establish reliability rules for natural gas infrastructure, requiring cold weather plans, freeze protection, and operating measures for extreme cold weather periods
Rec. 6: Voluntary measures for natural gas facility cold weather preparedness	(states)		Related to Elliott Rec.	Rec. 6: Commission consider whether to have jurisdictional gas entities provide one-time reports on assessing, responding to natural gas vulnerabilities in extreme cold weather
Rec. 7: Establish natural gas-electric reliability forum	100%	NAESB, Commission Forums, NAESB Report		---
Rec. 8: Understanding generator natural gas contract risks	50%	NERC drafting new fuel assurance/risk guideline		---
Rec. 9: (Seasonal) Peak load forecasts and reserve margin calculations	100%	Incorporated in NERC Winter Assessment	Related to Elliott Rec.	Rec. 10: joint-regional reliability assessments of electric grid conditions during extreme cold weather periods, for use in power supply planning to reduce the risk of firm load
Rec. 11: Generator cold weather effects-mechanical, electrical systems	0%	observation from Elliott event inquiry	Related to Elliott Rec.	Rec. 2: Technical review of root causes of generator cold-related mechanical/electrical outages to identify prevention measures, determine if additional Standards are needed
Rec. 12: Generator use of weather forecasts for operating plans	50%	observation from Elliott event inquiry		---
Rec. 14: Natural gas production facilities SCADA control	(states)			---
Rec. 16: Improve Near-term Load Forecasts	0%	observation from Elliott event inquiry	Related to Elliott Rec.	Rec. 9: BAs should improve their short-term load forecasts for extreme cold weather periods cold weather periods by implementing the lessons and practices identified below and sharing newly identified effective practices with peer BAs for continuous improvement
Rec. 17: Analyze Intermittent Generation to improve Load Forecasts	50%	observation from Elliott event inquiry		
Rec. 19: Retail Incentives for Energy Efficiency Improvements	(states)			---
Rec. 23: Report Times for Generation and Transmission Outages	25%	observation from Elliott event inquiry		---
Rec. 24: Study: Measures to Address Natural Gas Supply Shortfalls	50%	NERC & NERC RAS	Related to Elliott Rec.	Rec. 7: Study: analyze whether additional natural gas infrastructure, including interstate pipelines and storage, is needed to support reliability of electric grid, meet needs of LDCs
Rec. 28: Study: Guidelines to Identify Critical Natural Gas Facility Loads	(states)	Now Required in Texas	Related to Elliott Rec.	Rec. 4c: Establish rules requiring designation of critical natural gas infrastructure loads for priority treatment during load shed
Average Percent Addressed (excluding state-level recs.) - URI:	**49%**			Rec. 4b: Establish rules requiring establishing regional natural gas communications coordinators, with situational awareness ofnatural gas infrastructure similar to grid's RCs
Number of state-level recommendations to help support prevention - URI:	5			Rec. 5: The North American Energy Standards Board should convene natural gas / electric grid / LDC entities to identify communication improvements during extreme cold
				Rec. 8: BAs assess whether new or modified processes, such as multi-day risk assessment processes or advance reliability commitments are needed to address anticipated capacity shortages or transmission reliability problems during extreme cold weather
Emergency Response-Oriented Recommendations				
Rec. 10: Improve rotational load shed plans	90%	NERC RAS & RTOS		---
Rec. 13: Study of ERCOT generators to review low-frequency effects	10%	PRC-024 SDT, combined with Rec. 27 effort		---
Rec. 15: Develop or enhance emergency response centers	(states)			---
Rec. 18: Additional Rapidly-Deployable Demand Response	(states)			---
Rec. 20: Perform Bi-Directional Seasonal Transfer Studies	90%	NERC RAS & RTOS		---
Rec. 21: Operator-Training Rotational Firm Load Shed Simulations	100%	NERC RTOS		---
Rec. 22: Generator Protection Settings/ UFLS Coordination	100%	ERCOT completed		---
Rec. 25: Study: Additional ERCOT Interconnection Links	100%	ERCOT, completed		---
Rec. 26: Study: ERCOT Black Start Unit Reliability	98%	FERC/ERO Report near completion	Related to Elliott Rec.	Rec. 3: Study: Black start unit reliability covering all portions of the U.S. not already studied
Rec. 27: Study: Low-Frequency Effects in Eastern, Western Interconnects	10%	NERC SME staff assigned; gathering data	Related to Elliott Rec.	Rec. 11: Study: examine potential stability risks on December 23-24 for periods of decreased frequency and low responsive reserves during Winter Storm Elliott
Average Percent Addressed (excluding state-level recs.) - URI:	**75%**			
Number of state-level recommendations to help support response - URI:	2			



BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-9

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

Exhibit 44

PJM Elliott Report

Winter Storm Elliott

Event Analysis and Recommendation Report

July 17, 2023

For Public Use

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Executive Summary

Winter Storm Elliott hit the eastern United States over the Dec. 23–25 weekend and tested the reliability of much of the Eastern Interconnection. Precipitous temperature drops and powerful winds caused widespread generator failures and froze up natural gas supplies while driving up electricity demand, leading to power outages in some of PJM's neighbors.

PJM and its members were able to maintain the reliability of the system, serve customers and even support neighboring systems during some periods, which was a significant accomplishment. Specifically, PJM operators were able to avoid electricity interruptions throughout this event. Nevertheless, PJM operators had to implement multiple emergency procedures and a public appeal to reduce energy use to maintain reliability in the PJM footprint serving 13 states and the District of Columbia.

Advanced Planning

As documented in this report, PJM was prepared for the 2022/2023 winter, as well as Winter Storm Elliott, based on the information available, and conducted extensive preparations and communications with members, adjacent systems and the natural gas industry in advance of the storm, in addition to the regular steps PJM takes each year to prepare for winter.

PJM's annual pre-winter analysis indicated that PJM would have enough generation to meet load even under a combination of extreme and unlikely conditions, including pipeline disruptions similar to those previously seen under similar winter conditions, close-to-zero wind/solar generation, high generation outages and extreme weather. Despite numerous refinements to both the capacity market rules and winter preparation requirements that came out of the 2014 Polar Vortex, Winter Storm Uri in 2021, and other recent examples of increasingly extreme weather patterns, Winter Storm Elliott created a convergence of circumstances that strained the grid.

PJM's load forecasts for Dec. 23 and Dec. 24 were approximately 8% under the actual peak. The modeling challenges that resulted in this under-forecast are detailed in this report. Given the operational uncertainty, PJM operators scheduled prudently on both days (in excess of the actual load plus reserve requirements).

Operations and Generator Performance

Elliott's rapidly falling temperatures coincided with a holiday weekend that combined to produce unprecedented demand for December. This was further complicated by unexpectedly high resource unavailability and/or failures to perform.

On the first day of the storm, Dec. 23, the stress on PJM's neighbors began to signal extreme conditions headed for the region PJM serves. The Southwest Power Pool (SPP) set a new winter peak that day; the Tennessee Valley Authority (TVA) experienced the highest 24-hour electricity demand supplied in its history. PJM exported energy to TVA, Duke Carolinas and Duke Energy Progress before having to curtail most exports during peak conditions in the face of emergency conditions.

PJM's forecast for Dec. 23 was about 127,000 MW, and load came in at about 136,000 MW. This demand level is approximately 25,000 MW above a typical winter peak day. In preparation for this day, PJM had approximately 158,000 MW of operating capacity based on what was scheduled in the Day-Ahead Market plus available generation able to be called upon in real time. PJM was able to meet this load with the help of a Maximum Generation Action and Demand Response. Looking to Dec. 24, the coldest day of the weekend, PJM operators decided to schedule conservatively in terms of reserves (the electricity supplies that are not currently being used but can be quickly available in the case of an

unexpected loss of generation). Based on the information it had received from generation resources, PJM anticipated that approximately 155,700 MW of generation should have been available for Dec. 24.

Complications arose on Dec. 24 resulting from the unanticipated failure of generation resources that were called into the operating capacity on that day. At one point, almost a quarter of the generation capacity – 47,000 MW – was on forced outages. While generators are required to provide updates on their operating parameters, including operating status, ramp times and fuel availability, in 92% of generator outages, PJM operators had an hour's notice or less – in most cases, PJM was informed of outages when dispatchers called generators to request them to turn on.

When examined over the entire generation fleet, gas generators accounted for 70% of the outages on Dec. 24. Most outages were caused by equipment failure likely resulting from the extreme cold, though broader issues of gas availability also contributed to the outages.

Market Outcomes

Elliott was the first wide-scale use of PJM's Capacity Performance rules, which were introduced in 2016 as a market tool to incent generator performance following the 2014 Polar Vortex – a similar event characterized by extreme cold weather and high forced outage rates. The high outage rates for generators during Winter Storm Elliott resulted in substantial Non-Performance Charges that are part of Capacity Performance rules. As of this report, PJM estimates there are approximately $1.8 billion in Non-Performance Charges based on the current rules. Those charges are allocated to suppliers that exceeded their committed capacity level.

Outreach

PJM's communications and government policy teams relayed critical situation updates in a timely fashion; short operational update videos from PJM leadership were used to reach a wide audience by television, print and digital media, while external-facing personnel used the same videos to update their important state and federal contacts. The Call for Conservation was widely amplified by Transmission Owners, regulators and even governors' offices on social and traditional media, and PJM is looking at strategies to build on that effective partnership.

Recommendations Overview

The analysis of PJM's experience during Winter Storm Elliott confirms the decisions by PJM planners and operators in preparing for and navigating through the storm, including communications, emergency procedures, and the scheduling and management of interchange in support of the Eastern Interconnection. In addition, the capacity market's performance rules were implemented as written in the Tariff and manuals.

At the same time, Elliott also provides some clear lessons for PJM and its stakeholders that drive the 30 recommendations contained in this report. These recommendations are broadly focused on:

- Addressing winter risk with enhancements to market rules, accreditation, forecasting and modeling
- Improving generator performance through winterization requirements, unit status reporting and testing/verification
- Tackling long-standing gaps in gas-electric coordination, including timing mismatches between gas and electric markets, the liquidity of the gas market on weekends/holidays, and the alignment of the electricity market with gas-scheduling nomination cycles
- Evaluating how the Performance Assessment Interval (PAI) system of rewarding or penalizing generator performance is impacted by exports of electricity to other regions, whether excusal rules can be simplified, PAI

triggers need to be refined, and if the contributions of Demand Response and Energy Efficiency are accurately valued

- Pursuing opportunities with Generation Owners, other members and states to improve education, drilling and communication regarding PJM's emergency procedures, Call for Conservation and PAIs

Many of these recommendations, as indicated in the chart below, are currently being developed through the Critical Issue Fast Path – Resource Adequacy process or through other forums.

Recommendations

ID	Category	Recommendation	Type	Status
1	Resource Performance	Evaluate needed enhancements to the generator Cold Weather Checklist and the Cold Weather Operating Limit reporting practices used to prepare for cold weather to help improve generator cold weather performance in the future. Incorporate lessons learned as necessary to improve these checklists to include validation procedures. Evaluate reasons why the information provided by Curtailment Service Providers regarding their ability to curtail load was not accurate. Incorporate lessons learned as necessary to include validation procedures.		Under internal PJM review
2	Emergency Procedures	Reinforce PJM and member steps and expectations in Manual 13 for operation during emergency procedures through additional training and manual clarifications. Specific focus on: • Existing actions in Cold Weather Advisory and Cold Weather Alert regarding winterization and staffing procedures • Criteria, sequencing, and communication of alerts, warnings and actions • Consideration of potential opportunities to clarify member expectations in M-13		New
3	Operating Reserves	Evaluate triggers for increasing the Operating Reserve Requirements in advance of the operating day based on risks imposed by projected extreme temperatures, unusual temperature changes, load uncertainty, solar/wind uncertainty, generator performance uncertainty, OFOs, etc.		Pending internal process change
4	Load Forecast	Evaluate opportunities for improvements to the extreme weather load forecast processes and methodology with independent and peer analysis.		Under internal PJM review
5	Unit Parameters	PJM will provide additional training relating to the use of Parameter Limited Schedules (PLS) and price schedules. The focus of the training will include the time to start parameters for the various schedule types and the use of PLS parameters. The intended training audience is for anyone managing and updating the PLS and price schedules.		New

ID	Category	Recommendation	Type	Status
6	Unit Status	Evaluate the Temporary Exception and Real-Time Value processes that require gas-fired generators to either update their operating parameters, or confirm that no updates are needed, when Cold Weather Advisories, Alerts, Conservative Operations, or pipeline OFOs are issued that may impact their ability to procure gas outside of standard nomination timelines. Make improvements to ensure accurate offer information from generation resources.		Under discussion at the Electric Gas Coordination Senior Task Force (EGCSTF)
7	Gas Electric Coordination	Develop solutions to address near-term gas generator unavailability resulting from gas and electric market timing issues, particularly during periods of cold temperatures and high winter demand.		Under discussion at the EGCSTF
8	Gas Electric Coordination	Explore opportunities to increase alignment between the scheduling of natural gas-fired resources with nomination cycles.		Under discussion at the EGCSTF
9	Gas Electric Coordination	Evaluate the current multi-day commitment process for use during expected critical high demand periods so as to analyze the costs and benefits of providing greater certainty of fuel supply procurement through the critical period, with a focus on weekends when the gas commodity market can be less liquid.		Under discussion at the EGCSTF
10	Gas Electric Coordination	Provide recommendations to FERC to investigate weekend gas supply liquidity to facilitate increased gas procurement ability during weekend/holiday periods.		Under discussion at the EGCSTF
11	Gas Electric Coordination	Work with states to discuss opportunities to increase prioritization of natural gas for usage in electricity production for resources behind LDCs.		Under discussion at the EGCSTF
12	Gas Electric Coordination	Explore opportunities to better align submitted offer data to true availability of natural gas resources.		Under discussion at the EGCSTF
13	Gas Electric Coordination	Evaluate the ability to include fuel-specific information in the capacity accreditation model. Consider including items such as: 1. Different levels of fuel security, including dual-fuel capability, firm gas and non-firm gas 2. Minimum requirements for onsite fuel		Under discussion in the CIFP process
14	Unit Status	Evaluate options for requiring generators to provide procurement information to PJM in real time and day ahead to provide greater situational awareness to PJM regarding the ability and timeliness of procuring fuel.		Under discussion at the EGCSTF
15	Voltage Reduction	Review and update, as necessary, the expected load reduction achieved during a Voltage Reduction Action due to changing composition of load. This recommendation specifically focuses on the Voltage Reduction Summary table in Manual 13.		New

ID	Category	Recommendation	Type	Status
16	Reserve Performance	Evaluate opportunities to increase the performance of Synchronized Reserves to achieve the desired response. This may include levels procured, procurement practices, compensation or other aspects of the Reserve Market design.		Stakeholders notified that PJM's reserve requirement will be increased to 1.3 times the largest contingency MW effective May 19 until further notice
17	Reserve Pricing and Penalties	Evaluate the current Reserve Market design to ensure reserve products, estimated reserve capabilities on resources, procurement practices and timelines, quantities procured, performance incentives, etc., align with operational needs and that prices and performance incentives are similarly aligned.		Issue charge planned for August
18	Cost Offer Verification	Distribute training on the Cost Offer Verification process to members (standard email or similar notification) before cold weather events and send alerts to update MIRA ahead of time.		New
19	CIFP	Evaluate how risk modeling in the reliability analysis used in the capacity market can be improved to better account for the drivers of reliability risk experienced in the winter.		Under review at the CIFP
20	CIFP	Evaluate reforms to capacity market rules and incentives to improve the performance of resources, including: • Review the Capacity Performance construct, with consideration of financial risks. • Strengthen capacity accreditation and qualification criteria (e.g., winterization/fuel assurance). • Evaluate opportunities to improve testing rules to complement assessments during actual reliability events, including frequency of the tests, defined guidelines for test success/failure, and penalties for test failure. • Evaluate current practices in other ISO/RTOs for requiring generator inspections and implement any best practices.		Under review at the CIFP
21	CIFP	Evaluate opportunities to align the incentives from the capacity market via PAIs with real-time operating conditions, particularly with regard to PAI triggers.		PJM filed changes to the PAI triggers on May 30. Discussions will continue as part of the larger reforms in the CIFP process.
22	CIFP	Evaluate if and how exports should be accounted for in the balancing ratio.		Under review at the CIFP
23	CIFP	Reevaluate what happens in the scenario that a resource has not submitted a valid offer.		Under review at the CIFP
24	CIFP	Explore opportunities to refine and simplify excusal rules to reduce manual and case-by-case review processes.		Under review at the CIFP

ID	Category	Recommendation	Type	Status
25	CIFP	Review the M&V calculations of Energy Efficiency and Demand Resources for PAIs to assess if the determination of actual performance and bonus accurately reflects the reliability benefit provided.		Under review at the CIFP
26	CIFP	Evaluate the performance issues regarding NRBTMG, and provide recommendations on enhancing its performance or altering its participation in the capacity market.		Reviewed at the May 8 DISRS Stakeholder group
27	CIFP	Explore opportunities for further education on PAIs, such as providing periodic training sessions.		In Progress
28	Call for Conservation	Evaluate opportunities to enhance Public Notification Language in Attachment A of Manual 13 regarding Call for Conservation to better direct the appeal to all customers, not just residential. Establish a process for annual review of state alert contacts, and explore additional opportunities to further amplify PJM's message through state communication channels, up to and including Emergency Alert Systems.		In Progress
29	Outreach	Operations, Corporate Communications and SGP will seek ways to enhance communications, specifically looking at timeliness, relevance and clarity of information provided along with curating and updating of appropriate contacts for each audience and channel for messaging.		In Progress
30	Drills & Exercises	Operations, Corporate Communications and SGP will also strengthen their periodic drilling with states, Transmission Owners and other members by: 1) Finding opportunities to include states in PJM crisis exercises; 2) Providing education on PJM emergency procedures and Call for Conservation during summer and winter operations drills; 3) Following up with parties not represented at drills to make sure they are aware and contacts are up to date.		In Progress

Legend for Type

- Operational Change
- Market Construct Process Change or Addition
- Process Improvement
- Training and awareness improvement

About This Report

Purpose

The purpose of this analysis and subsequent report is to review the events up to and during Winter Storm Elliott, assess the actions of PJM and its members during those times, and look for lessons learned and associated recommendations to help improve grid reliability.

Analysis Process

The review process performed for this report was driven by the Human Performance and Operating Experience (HP&OE) program at PJM. The HP&OE program promotes excellence in human performance through behaviors that support reliable grid operations, fair and efficient energy markets, and infrastructure planning. The goals of this program are to:

- Reduce the frequency and impact of human error
- Share and learn from internal and external events
- Analyze events to identify corrective actions to prevent and reduce impacts of adverse events
- Ensure that processes and procedures are executed correctly to achieve the desired results

The fundamental aspects of the HP&OE program are:

- Prevention: Reduce errors that lead to events
- Detection: Identify potential issues across the organization
- Correction: Learn from events through event analysis and completion of remedial actions

To conduct this review and event analysis, PJM employed the Learning Teams analysis tool. Learning Teams are utilized in the industry as a collaborative event analysis best practice because it focuses on bringing people together to better understand an event with the basis on learning and identifying successes and improvements.

PJM conducted multiple different focused area Learning Team sessions with subject matter experts and independent participants across various areas of PJM to allow for open and collaborative discussions. The Facilitation Team followed a structured and consistent methodology with a focus on the event itself, and additionally on the timeline and decisions leading into the event, which allowed all members of the team to share their perspective. From the Learning Team sessions, successes and opportunities for improvement were identified that lead to recommendations for future analysis of enhancements to rules and procedures. The recommendations from PJM's Learning Team's sessions on Winter Storm Elliott are contained in this report. The recommendations are then tracked through the HP&OE program until they are resolved.

Organization of This Report

This report outlines the operational preparations that PJM takes in advance of winter generally, and took for Winter Storm Elliott during the Dec. 23–25 holiday weekend specifically, including emergency procedures, communications with members and forecasting. It documents the operating conditions PJM operators faced and the actions they took, and it details the working of the PJM markets just before and during the storm. The Conclusion summarizes the processes and forums that will be used to act on the set of recommendations. For definitions of industry terms, consult the PJM Glossary on PJM.com.

Advance Preparations

Each year, PJM performs winter readiness assessments and exercises in advance of the cold weather months. These assessments include power flow analyses that simulate potential conditions on the power system for expected and extreme winter conditions, as well as a capacity "waterfall chart" to determine if adequate capacity is expected to be available based on various stress cases. This analysis is known as the Winter Operations Assessment Task Force Study.

In 2021, in light of the severe cold weather issues experienced in Texas during February 2021, PJM initiated an analysis that resulted in numerous additional improvements to its winter preparedness efforts. Those improvements included approving rules to assist Transmission Owners (TOs) in identifying and prioritizing service to critical facilities in emergencies, prohibiting Load Management programs from including any critical gas infrastructure, further improving information sharing with the natural gas industry, and confirming that TOs were prepared to rotate outages if load shedding was required.

PJM also collects data on generating resource fuel inventory, supply and delivery characteristics, emissions limitations, and minimum operating temperatures via the Seasonal Fuel Inventory and Emissions Data Request (PJM Manual 14D, Section 7.35) and also via Periodic Fuel and Emissions Data Requests issued as needed throughout the season. Furthermore, PJM validates that Generation Owners have adequately prepared for winter by requiring that they confirm they have completed the Cold Weather Preparation Guideline and Checklist.

Also, as a result of increasing supply chain risks to fuel deliveries, PJM initiated a weekly fuel and non-fuel consumables data request for all generators that utilize coal or oil as their primary or backup fuel. Capturing this data more frequently allows PJM to better understand any fuel supply, supply chain or transportation issues that could impact generators. Due to the continued concern with supply chain issues, the practice was extended through all of 2022, including the winter of 2022. Current system conditions do not necessitate this weekly data request but will be re-initiated, if necessary. These rule changes provided better visibility into generators' supply of fuels and other material critical to their operation and enhance the flexibility those generators need to rebuild their supplies when facing shortfalls beyond their control. The data requests did not identify any issues.

As described above, PJM prepares extensively for the peak winter season, including the following key annual activities:

- PJM Winter Operations Assessment Task Force Study
- Generation Resource Cold Weather Preparation Guideline and Checklist
- Cold Weather Resource Operational Exercise
- Pre-Winter Emergency Procedures Drill
- PJM Winter Readiness Meeting

This section details PJM's processes leading up to the storm, including regular winter preparations, issuing Cold Weather Advisories and Cold Weather Alerts, and other activities taken during the week of Dec. 18 in advance of Dec. 23 and Dec. 24.

PJM Winter Operations Seasonal Study

The PJM Operations Assessment Task Force (OATF) consists of representatives from PJM and PJM Transmission Owners. This team, under the direction of PJM, conducts seasonal studies for the summer and winter periods. Each

study analyzes the PJM system with the transmission and generation configuration approximating the expected conditions for that study period.

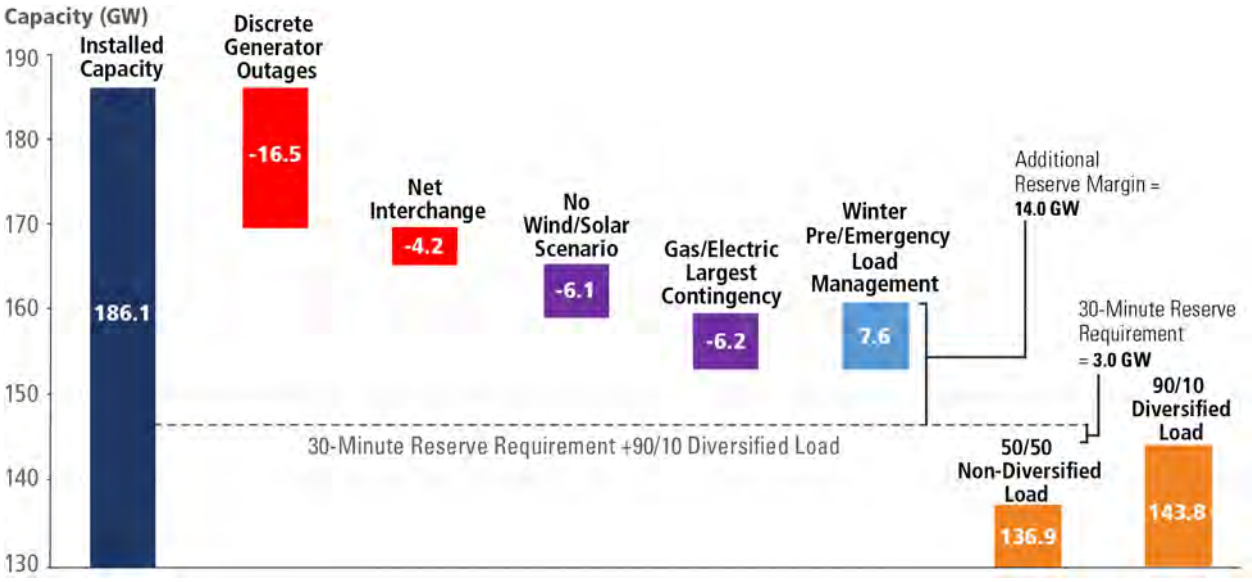
The study conditions include forecasted demand based on forecast weather and estimated outages, as well as a series of more extreme scenarios, including, but not limited to:

- External contingencies that could impact PJM reliability
- The loss of more than one bulk electric system (BES) element (N-1-1 relay trip conditions)
- A Maximum-Credible Contingency Analysis (e.g., loss of a substation, loss of multiple lines in a common right of way)
- An import capability analysis
- An extreme (90/10) load forecast study
- A solar and wind generation sensitivity study
- A gas pipeline disruption study

The results of this analysis indicated that there was sufficient generation for the 2022/2023 winter period to meet the demand under all studied conditions. The process for conducting the OATF study is documented in PJM Manual 38, Operations Planning, Attachment A.

As shown in Figure 1, PJM projected that more than adequate capacity should have been available for the 2022/2023 winter period.

Figure 1. Projected Capacity for 2022/2023 Winter Period



The OATF study is reviewed at the System Operations Subcommittee (SOS) and the Operating Committee (OC).

Generation Resource Operational Exercise

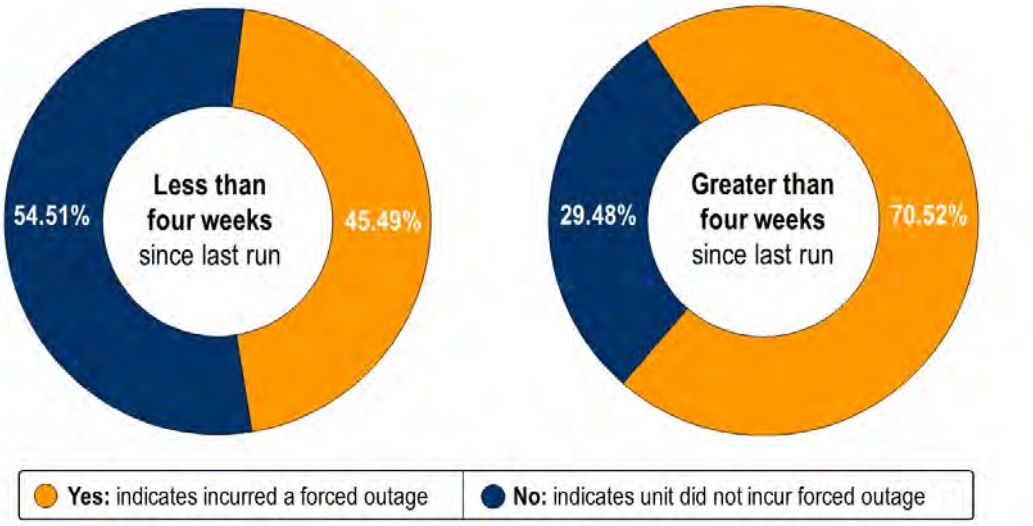
Following the 2014 Polar Vortex, PJM made several changes to its Cold Weather Operating Procedures, including establishing a Generation Resource Operational Exercise Program and a Generation Resource Cold Weather Checklist. The Generation Resource Operations Exercise Program is intended to enhance unit performance during cold weather operations and encourage generating units to be prepared for extreme cold weather and can start and run on alternate fuels, if necessary. The exercise assists in the identification and correction of start-up and fuel-switching problems (PJM Manual 14D, Section 7.5).

PJM also recommends that Generation Owners conduct an operational exercise prior to the onset of cold weather to validate a unit's cold weather operations. Specifically, PJM recommends that Generation Owners self-schedule any of their resources that have not operated in the eight weeks leading up to Dec. 1 to determine whether they are capable of reliably operating on both primary and alternate fuel and responding to PJM's dispatch instructions. Generation Owners are requested to submit an informational eDART ticket with a cause of "Cold Weather Preparation Exercise" to document that the generation resource has been scheduled to operate under the cold weather operational exercise.

The charts in Figure 2 present the forced outage rates during Elliott for units that had not run in the weeks leading up to the event. A four-week time period was used as the cutoff for the performance analysis. Those units that had not run in more than four weeks had higher forced outage rates. This data demonstrates that generators that had run in the few weeks prior to Winter Storm Elliott performed better than those that did not. As a result, PJM believes consideration should be given to making this currently recommended exercise a requirement.

When reviewing generator performance for units that did not operate for four weeks prior to Winter Storm Elliott, 70.5% of units incurred a forced outage during the event. This data supports continuing or expanding the Generation Resource Operational Exercise described in PJM Manual 14D, Section 7.5.1, which is currently recommended, but not required for Generation Owners to perform.

Figure 2. Forced Outages Versus Last Run Time



Generation Resource Cold Weather Preparation Checklist

Similarly, the Generation Resource Cold Weather Checklist (presented in PJM Manual 14D, Section 7.5 and Attachment N), or a similar one developed and maintained by the Generation Owner, should be used annually prior to the local

National Oceanic and Atmospheric Administration (NOAA) first frost date to prepare its generation resources for extreme cold weather event operations.

This checklist includes verification by Generation Owners that they have performed everything from increasing staffing for weather emergencies to performing required maintenance activities to prepare equipment for winter conditions. This checklist was first developed and issued to Generation Owners in 2014 and is updated annually as new industry lessons learned are published by NERC and others. For this winter, the checklist was updated to require information about a generating unit's cold weather operating limits. This was added as a result of the lessons learned from Winter Storm Uri.

The checklist identifies and prioritizes components, systems and other areas of vulnerability that may experience freezing problems or other cold weather operational issues such as safety staffing, equipment preparation, fuel preparation and environmental preparation; as well notes the actions to be taken when cold weather is forecast and actions during cold weather. Between Nov. 1 and Dec. 15 of each year, the Generation Owner is required to verify via eDART that the represented generation resources have completed the items on the checklist, or a substantially equivalent one developed by the Generation Owner. Ahead of Winter Storm Elliott, 99% of the generation resource owners in the PJM region verified that they completed the items on the Generation Resource Cold Weather Preparation Checklist or equivalent.

Table 1 summarizes the Cold Weather Checklist responses:

Table 1. Cold Weather Checklist Response Summary 2022

	Unit Count	Installed Capacity (MW)
Yes – Using Generation Owner Equivalent Guideline and Checklist	1,043	179,332
Yes – Using PJM Guideline and Checklist	270	16,974
No	52	1,262
No Response	37	238

The Cold Weather Checklist is discussed in the System Operations Subcommittee (SOS), Operating Committee (OC) and Market Reliability Committee (MRC). Additional information on generation performance is presented in the Operating Day section of this report.

Transmission Outage Deferrals

Transmission outage deferrals are an approved measure to promote the ability to transfer power across the RTO and promote an abundance of caution to be as prepared as possible. When PJM issues a Cold Weather Alert, PJM recalls/cancels non-critical transmission maintenance outages. Specifically, the following transmission outages were deferred or returned to service early:

- BLACKOAK-HATFIELD (eDART # 1053409 12/19 – 12/22) outage request was denied due to a conflict and cold weather.
- Two major outages returned to service early on Dec. 23. PJM was in close coordination with the TOs for the return of Mt. Storm-Valley 500 kV and the Malizewski-Marysville 765 kV lines.

Due to emergency procedures and multiple day-ahead outage approval processes, these lines were requested to be in service for Dec. 23.

Cold Weather Advisory

In advance of the mandatory North American Electric Reliability Corporation (NERC)[1] Winterization Standard becoming effective on April 1, 2023, PJM established the Cold Weather Advisory. A Cold Weather Advisory provides an early notice that forecast temperatures may call for a Cold Weather Alert. The early notification of an Advisory is intended to provide PJM members ample time to gather information required by NERC standards EOP-011, Emergency Preparedness and Operations, IRO-010 RC Data Specification and Collection, and TOP-003 Operational Reliability Data. Members are to take any necessary precautions to prepare generating facilities for cold weather operations. PJM attempts to issue the advisory as far in advance as possible, typically within three to five days, but given fluctuating and changing weather forecasts, advisories could be issued up to 24 hours in advance.

Members are expected to perform the following actions upon the issuance of a Cold Weather Advisory:

- Prepare to take freeze protection actions, such as erecting temporary windbreaks or shelters, positioning heaters, verifying heat trace systems, or draining equipment prone to freezing.
- Review weather forecasts to determine any forecasted operational changes and notify PJM of any changes.
- Update Markets Gateway by entering unit-specific operation limitations associated with cold weather preparedness, including the following limitations:
  - Generator capability and availability
  - Fuel supply and inventory concerns
  - Fuel switching capabilities
  - Environmental constraints
  - Generating unit minimums (design temperature, historical operating temperature or current cold weather performance temperature as determined by an engineering analysis)

PJM conducted a Cold Weather Advisory drill on Dec. 16, 2022. In advance of the drill at the December OC and the SOS meetings, PJM reviewed the objective of the upcoming drill and the expected member actions to be performed during the drill.[2]

Pre-Winter Emergency Procedures Drill

Pursuant to PJM Manual 13, PJM conducts emergency procedure drills prior to every summer and winter that include PJM, Generation Owners and Transmission Owners, and are focused on capacity shortage events. The drill encourages all entities to be familiar with the required actions and communications required for each emergency procedure, up to and including load shed action, as specified in PJM Manual 13, Emergency Operations.

On Nov. 3, 2022, PJM conducted the 2022 Winter Emergency Procedures Drill, testing established procedures for capacity shortages in accordance with conservative operations. Participants included PJM Operations, Dispatch staff and personnel from PJM Corporate Communications/State Government Policy, Local Control Centers and Market Operations Centers.

[1] NERC is a not-for-profit international regulatory authority whose mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid. NERC develops and enforces NERC Reliability Standards, which define the reliability requirements for planning and operating the North American bulk power system.
[2] Cold Weather Advisory Process, PJM System Operations Subcommittee, Dec. 2, 2022.

The following emergency procedures were implemented in the simulation stage of the drill: Cold Weather Alert, Low Voltage Alert, Maximum Generation Emergency Alert, Unit Startup Notification Alert, Primary Reserve Alert, and a Voltage Reduction Alert. All emergency procedure warnings and actions were issued as part of the drill to encourage participants to properly notify government agencies and to exercise internal communications for each member company.

Information about the drill scenario is contained in a packet sent to external participants and in a script for PJM staff. PJM also offers an eLearning module each year in support of the drill. This online training course, available via the PJM Learning Management System on the PJM website, provides an overview of the emergency procedures that participants may encounter during the drill exercise.

The plans for the drill are reviewed at the Dispatcher Training Subcommittee (DTS), the SOS and the OC.

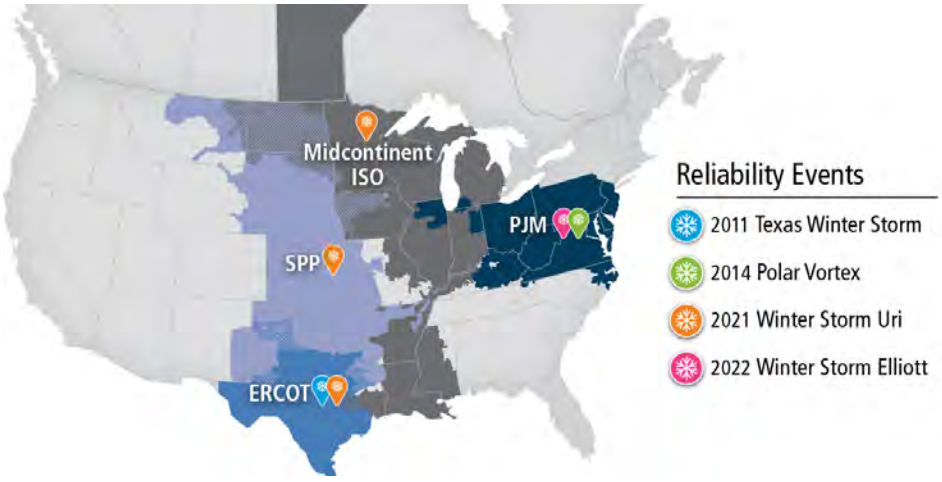
Reliability Analysis Used in the Capacity Market

PJM performs several reliability studies that inform the clearing of the capacity market.

- Installed Reserve Margin (IRM) Study – Study run by PJM that determines the amount of reserves beyond the peak load necessary to maintain a Loss of Load Expectation (LOLE) of one event in 10 years
- Capacity Emergency Transfer Objective (CETO)/Capacity Emergency Transfer Limit (CETL) Studies – Studies run by PJM to determine if the transmission system is capable of delivering enough energy to Locational Deliverability Areas (LDA) to meet reliability targets
- Accreditation – Calculation performed by PJM to determine how much capacity a resource can sell as a percentage of its nameplate capacity

These studies all assume that the reliability risk PJM may face aligns with peak loads, which typically occur in the summer. The assumption behind coinciding reliability risk with peak loads is that if enough capacity is scheduled for the expected peak load, it will also be sufficient for all other hours in the year. However, recent history in PJM and other RTO/ISOs indicates that reliability risk also occurs outside of the peak load and may be trending away from the peak to something else. Figure 3 presents the recent reliability events outside the peak load periods.

Figure 3. Recent Reliability Events



Finding the causes behind these events is important to determine how PJM's reliability risk modeling may need to be adjusted to better capture the likelihood, severity and patterns of risk. PJM and stakeholders are already working on identifying and modeling these new risks.

PJM Winter Readiness Meeting

PJM also conducts an internal, cross-divisional meeting each fall to review each PJM department's preparedness for winter operations. It includes discussions and presentations by PJM's Operations, Markets and Planning divisions. The following topics are addressed in these cross-divisional meetings:

- Weather and load forecast outlook
- Review of winter OATF study (including base case parameters, peak load study results and sensitivity studies)
- Potential gas/electric concerns for upcoming peak period
- Interconnection projects update (including key project upgrades and delays, generation additions and retirements, review of additional reactive resources coming online, generation preparation, outage and performance updates)
- Review of NERC Standard FAC-014, Requirement 6, list of multiple facility contingencies (if any) that result in stability limitations
- Review of any specific concerns or questions from PJM's Dispatch, Reliability Engineering and Markets personnel

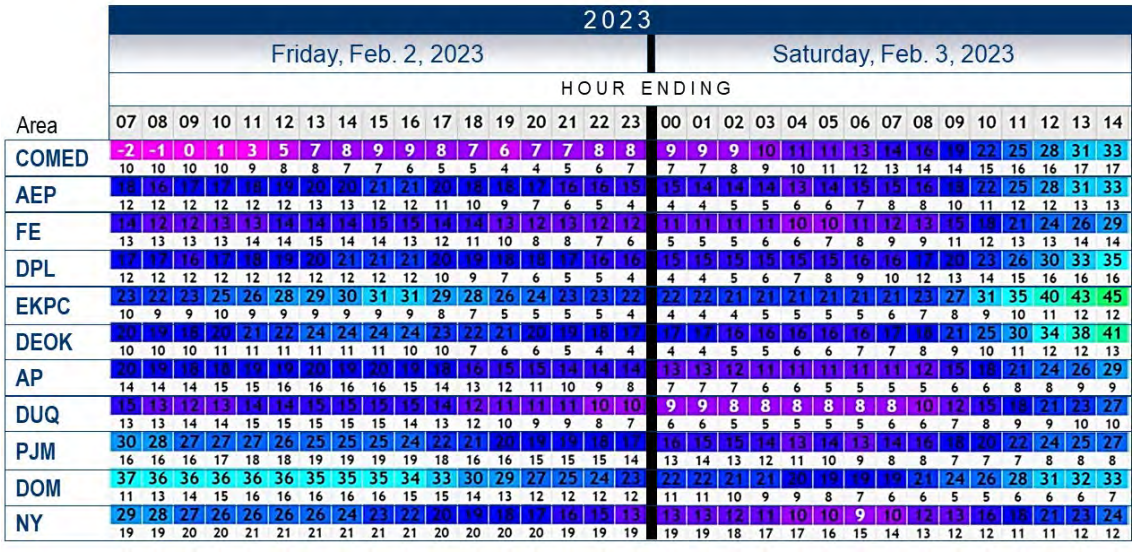
Preparations Ahead of Winter Storm Elliott

In preparation for Winter Storm Elliott, PJM performed the established load forecast planning process, issued Advisories and Alerts, and coordinated activities with both the adjacent systems and the natural gas industry. PJM also planned for the commitment of resources needed to meet the Dec. 23 and Dec. 24 operating days' demand and reserve requirements.

Load Forecast Planning Process

PJM uses a vendor tool to view forecast weather conditions up to 14 days out. At six days out, PJM begins to receive hourly weather forecast data from three separate vendors for 28 weather stations dispersed throughout the PJM region. This data is visualized in a heat map tool used by PJM system operators and engineers. Figure 4 presents a sample of the heat map tool for Feb. 2 and Feb. 3, 2023. This is an example of a wintertime heat map and does not present the actual temperatures from Winter Storm Elliott.

Figure 4. PJM Heat Map Tool Example



PJM's forecast team and Dispatch leadership also receive detailed weather forecast reports from vendors at various time horizons warning of extreme weather conditions. The PJM forecast team reviews and synthesizes data from all of these sources and delivers daily verbal reports on upcoming weather at the daily Dispatch morning meeting. The PJM forecast team supplements this communication with email summaries and dialogue with PJM system operators.

The load forecast is first performed six days out using a performance-weighted average of the three weather vendor forecasts as inputs. A suite of models trained on three years of historical data generate separate load forecasts that are then combined into one ensemble forecast using another weighted average system. Both the ensemble forecast and individual model forecasts are updated each hour as load actuals and updated weather forecast data is received.

To create the next-day load forecast, PJM Operations support staff reviews weather conditions and recent load forecast performance each day, then integrates this information with known strengths, weaknesses and biases of each model to identify adjustments to the forecast. The support staff then communicates the recommended adjustments to Dispatch, and the two groups collaborate to finalize the forecast. Extra attention is given to holidays, where the models have increased forecast error due to closures of schools and businesses and altered human behavior. Starting at least two days out, the team analyzes model error and weather conditions from that holiday in previous years, then calculates adjustments to counter repeated model biases.

The relationship between load and temperature can change with time, as behind-the-meter solar, data centers, and new types of appliances are connected to the system. PJM monitors these changes, continually evaluates load patterns to assess impacts, and retrains and enhances the models, as needed. Staff analyzed electric heating statistics from the Energy Information Administration and determined that there does not appear to be a significant transition to electric heating in the PJM footprint that would have caused under-forecasting of winter load.

The PJM Operations staff conducted the following load forecasting activities in advance of the Winter Storm Elliott event:

Date	PJM Team	Activity
Mon. Dec. 19:	Forecast	• Alerted PJM Dispatch of upcoming blizzard conditions and extreme cold via email • Met to discuss holiday forecasts (with extra support from other staff)
Tues.–Fri. Dec. 20–23	Forecast	• Delivered verbal updates on approaching storm risks at the daily Dispatch morning meeting
Wed.–Fri. Dec. 21–23	Forecast	• Provided on-site support, meeting daily with dispatchers to support adjusting the forecast
Thurs. Dec. 22	Dispatch + Forecast	• Collaborated on the load forecast for Dec. 23, increasing the peak forecast to 127,000 MW from the original forecast of 124,600 MW
	Forecast	• Created the preliminary forecast for Dec. 24 with a maximum peak of 124,000 MW
Fri. Dec. 23	Dispatch + Forecast	• Collaborated on load forecast for Dec. 24

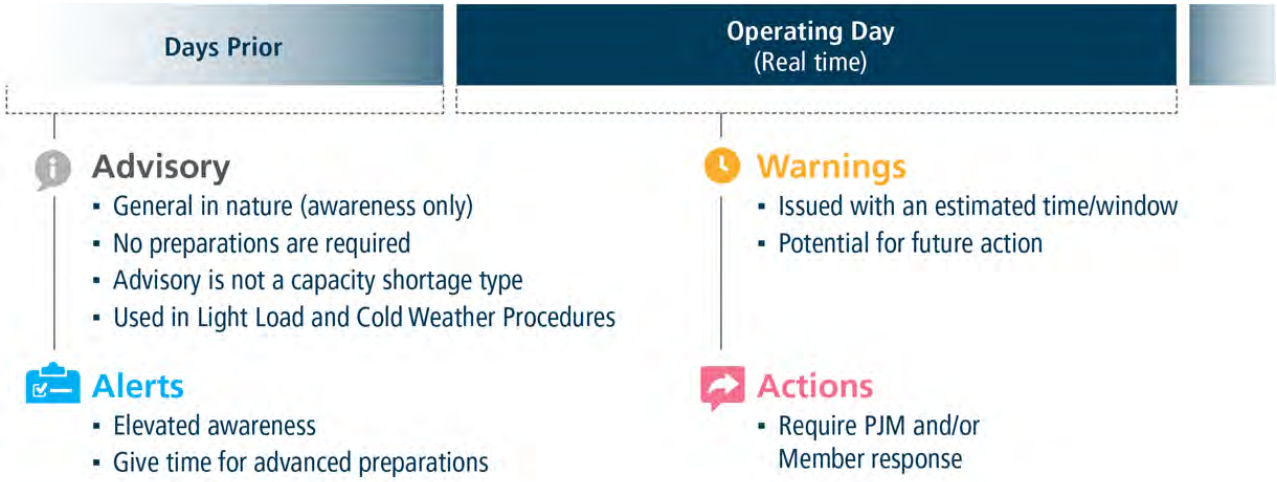
Date	PJM Team	Activity
	Forecast	• At the time of the forecast's creation, the actual load on Dec. 23 was coming in lower than the forecast. When the team began assessing the forecast for Dec. 24, they observed that the actual load was coming in lower than the previous day's forecast. This led the team to determine that holiday impacts were causing the load to come in low and that effect would persist into Dec. 24. • The PJM forecast team created the preliminary load forecast for Dec. 26.
Sat.–Mon. Dec. 24–26	Forecast	• Continued to provide load forecasting guidance and support to Dispatch

Emergency Procedures Issued and Actions Taken in Advance of Operating Day

PJM is responsible for determining and declaring that an emergency is expected to exist, exists or has ceased to exist in any part of the PJM RTO or in any other Control Area that is interconnected directly or indirectly with the PJM RTO. PJM directs the operations of the PJM members, as necessary, to manage, allocate or alleviate an emergency. PJM also is responsible for transferring energy on the PJM members' behalf to resolve an emergency, as well as executing agreements with other Control Areas interconnected with the PJM RTO for the mutual provision of service to meet an emergency.

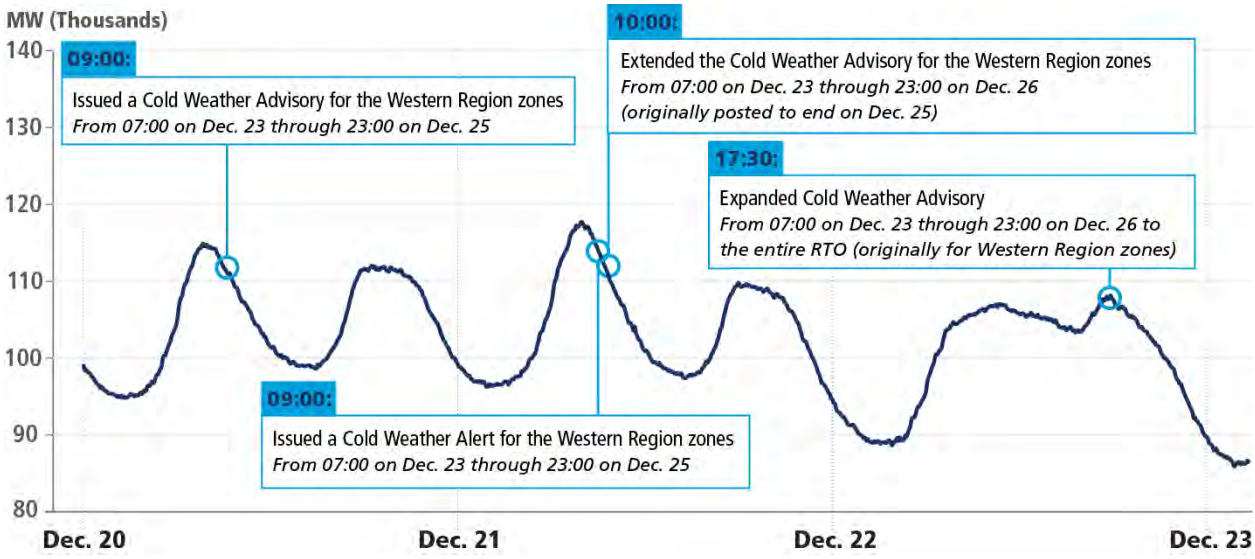
As described in PJM Manual 13, Section 2.3, PJM has established three emergency procedure levels for capacity shortages, as well as an advisory level.

Figure 5. Emergency Procedure Levels



To maximize PJM's ability to operate reliably during periods of extreme and/or prolonged severe weather conditions, procedures are necessary to keep all affected system personnel aware of the forecast and/or actual status of the system and to promote the maximum levels of resource availability are attained. PJM issued both advisories and alerts in the days leading up to Dec. 23 and Dec. 24, as presented in Figure 6:

Figure 6. Cold Weather Alerts and Advisories for Dec. 23 and 24



PJM initiated the following steps in advance of the Dec. 23 and Dec. 24 operating days:

- At 09:00 on Dec. 20, PJM issued a Cold Weather Advisory for the Western Region zones from 07:00 on Dec. 23 through 23:00 on Dec. 25. Members are to take any necessary precautions to prepare generating facilities for cold weather operations, including the following actions:
- Erecting temporary windbreaks or shelters, positioning heaters, verifying heat trace systems, or draining equipment prone to freezing
- Updating Markets Gateway by entering unit-specific operating limitations associated with cold weather preparedness (i.e., generator capability and availability, fuel supply and inventory concerns, environmental constraints)
- At 09:00 on Dec. 21, PJM issued a Cold Weather Alert for the Western Region zones from 07:00 on Dec. 23 through 23:00 on Dec. 25. At 10:00 on Dec. 21, PJM also extended the Cold Weather Advisory for the Western Region zones from 07:00 on Dec. 23 through 23:00 on Dec. 26. The purpose of a Cold Weather Alert is to prepare personnel and facilities for expected extreme cold weather conditions. PJM generally issues a Cold Weather Alert when the forecast weather conditions approach minimum or actual temperatures of 10 degrees Fahrenheit or below. PJM can initiate a Cold Weather Alert at higher temperatures if PJM anticipates increased winds or if PJM projects a portion of gas-fired capacity is unable to obtain spot market gas during load pick-up periods. When a Cold Weather Alert is issued, members are to perform the following actions:
- Update their unit parameters, including the Start-up and Notification, Min Run Time, Max Run Time, Eco Min, Eco Max, etc., in Markets Gateway.

- Report to PJM Dispatch any resource limited facilities, as they occur, via Markets Gateway.
- Determine whether alternate fuel will be made available to PJM for dispatch. If made available, any known alternate fuel resource limitations will be communicated via Markets.
- Based on direction received from PJM, call in or schedule personnel in sufficient time to ensure that all combustion turbines and diesel generators that are expected to operate are started and available for loading when needed for the morning pick up.
- At 17:30 on Dec. 22, PJM expanded its Cold Weather Advisory from 07:00 on Dec. 24 through 23:00 on Dec. 26 for the entire RTO. Given the expected weather, PJM was very prudent in developing the operating plans for Dec. 23, as presented throughout this section.

Figure 7 presents the expected member actions for the Advisories and Alerts that were issued in advance of the Dec. 23 and Dec. 24 operating days:

Figure 7. Expected Member Actions for Advisories and Alerts for Dec. 23 and Dec. 24

Dec. 20, 2022

Cold Weather Advisory for Western Region From Dec. 23–26 (Later Expanded to Entire RTO)

- Prepare to take freeze-protection actions, such as erecting temporary windbreaks or shelters, positioning heaters, verifying heat trace systems, or draining equipment prone to freezing.
- Review weather forecasts, determine any forecasted operational changes, and notify PJM of any changes.
- Members are to update PJM with operation limitations associated with cold weather preparedness. Operating limitations include: generator capability and availability, fuel supply and inventory concerns, fuel switching capabilities, environmental constraints, generating unit minimums.

Dec. 21, 2022

Cold Weather Alert Issued for the Western Region for Dec. 23–26 (Later Expanded to Entire RTO)

- Generation dispatchers review fuel supply/delivery schedules in anticipation of greater-than-normal operation of units.
- Generation dispatchers monitor and report projected fuel limitations to PJM dispatcher and update the unit Max Run field in Markets Gateway if less than 24 hours of run time remaining.
- Generation dispatchers contact PJM Dispatch if it is anticipated that spot market gas is unavailable, resulting in unavailability of bid-in generation.

Coordination With Adjacent Systems

In addition to its internal preparations for peak conditions, PJM also coordinates with adjacent systems prior to possible emergency conditions. This coordination can occur through the regional reliability entity responsible for compliance with NERC standards in that region or with the neighboring entity itself.

PJM participates in a daily morning conference call with adjacent systems at 03:30 during which peak load estimates, reserve requirements and estimated loads are discussed. Participants on the call include Tennessee Valley Authority (TVA), Virginia-Carolina (VACAR), Midcontinent Independent System Operator (MISO), PJM and Florida Reliability Coordinating Council (FRCC). There is also a call at 05:00 that PJM conducts with NYISO and a daily call at 08:00 with MISO. Load projections, reserves and anticipated daily challenges are discussed on these calls as well.

During the aforementioned calls, expected conditions were reviewed, and load projections and expected reserve quantities were shared. Members of the Northeast Power Coordinating Council (NPCC), the regional reliability entity for New York ISO (NYISO), ISO New England (ISO-NE), Independent Electricity System Operator (IESO), the Canadian Maritimes, and New Brunswick Power, were anticipating large temperature drops from the incoming arctic air mass and temperatures to be in the single digits. Council members coordinated anticipated operating conditions from multiple transmission facilities that tripped from previous ice storms that had impacted Canadian entities. These transmission facilities limited the entities' ability to export energy to adjacent areas. Members of the NPCC were anticipating tight operating conditions from the reduction of imports and anticipated higher loads from the incoming arctic air mass and agreed to conduct further calls and coordination throughout the duration of the storm.

PJM also met with SERC Reliability Corporation members to review expected conditions and share information to prepare for the event. SERC members were in close coordination throughout the event as well. The FRCC issued conservative operations on Friday, Dec. 23. TVA was managing capacity concerns as they lost units over the midnight period from extreme cold conditions. TVA declared conservative operations on Dec. 23 and EEAs up to an EEA 3 at 05:12 on Dec. 23. Southwest Power Pool (SPP) issued a cold weather advisory along with a resource advisory. On Dec. 23, SPP set a new winter peak of 47, 214 MW. Its previous winter peak was 43,661 MW.

PJM met with MISO to prepare for the event. MISO was monitoring the Arctic air mass forecasted to move into the footprint beginning Dec. 21 and Dec. 22 that was pushing temperatures below normal. MISO was not anticipating any capacity or reliability concerns.

MISO's Outage Coordination Team was evaluating all planned transmission outages, in the event some may need to be delayed due to the cold temperatures. MISO continued to closely monitor the numerous gas pipelines' cold weather notices, and Operational Flow Orders (OFOs) for any potential impact to generation. MISO declared a maximum generation warning for its southern region on Dec. 23 from 09:15 until 13:00 as well as for its entire footprint from 17:30 to 22:00 EST on Dec. 23. PJM had two coordination calls with MISO on each day of the event to exchange information, one at 03:30 and one at 08:00.

The Southern Company Balancing Authority declared an EEA 1 at 01:09 and EEA 2 at 05:33 due to lower-than-optimal generation reserves. The Southern Company Balancing Authority received 1,000 MW of emergency energy from Florida Power & Light and 100 MW of emergency energy from MISO.

As described later in this report, PJM coordinated extensively with TVA throughout the event to coordinate interchange transactions and system conditions. PJM ran studies to simulate additional interchange being exported to its neighbors. PJM will continue to participate in seasonal assessments and preparedness with its neighbors and seek opportunities to enhance coordination with neighbors.

Coordination With Natural Gas Industry

Prior to each winter season, PJM, along with fellow members of the ISO/RTO Council Electric Gas Coordination Task Force, meet with the pipeline industry to review the upcoming winter and discuss mutual preparedness activities.

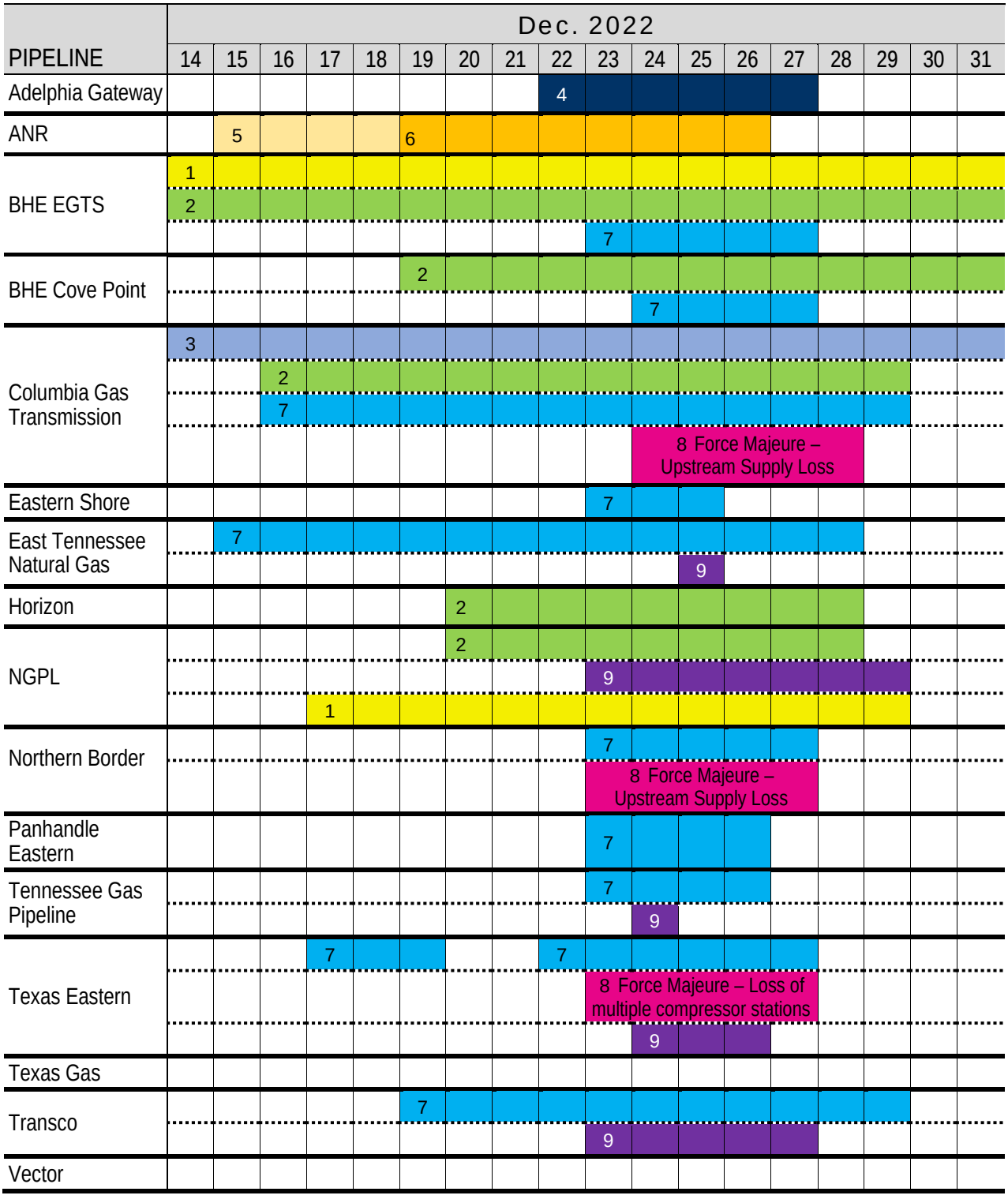
In addition to daily team meetings to review pipeline conditions and operational impacts, the PJM Gas-Electric Coordination Team conducts weekly operational calls during the winter months (November through March) with all of the major interstate natural gas pipelines within the PJM service territory. These interstate pipelines serve generation resources directly and also serve local gas distribution companies (LDCs), which in turn serve a smaller subset of PJM generators behind the LDC citygates. The purpose of these calls is to assess mutual system conditions. This includes reviewing load forecasts for both the electric and gas systems, any system outages that might impact service to

generators, active and pending pipeline capacity restrictions, and any gas generation pipeline nomination anomalies. As a result of FERC's issuance of Order 787, PJM established a Memorandum of Understanding (MOU) with nine of the major pipelines in 2015 and has individual agreements in place with the majority of pipelines and multiple LDCs. During critical gas pipeline capacity-constrained periods, LDCs have the ability to interrupt gas supply to certain gas-fired generators that are served behind the LDC citygates as generators are served at a lower priority level than core residential customers that are considered human needs customers. As such, it is important for PJM to understand when those generators may be interrupted, and for those generators subject to interruption to effectively communicate that information to PJM in a timely manner.

With respect to gas-electric coordination activities leading up to Winter Storm Elliott, these calls with the pipelines began early in the week immediately preceding the impacts of Elliott, and at that point, most of the pipelines had provided notification on their electronic bulletin boards announcing various cold weather alerts and system restrictions. This was in the form of OFOs and Ratable Take Requirements. OFOs are issued to enforce daily balancing rules requiring customer imbalances (difference between nominated gas volume and burned gas volume) to stay within a certain tolerance percentage. Ratable Take Requirements mandate that customers deliver and burn their gas at uniform hourly rates. Pipelines take these actions to mitigate large swings in system pressures. These restrictions gradually increased throughout the week, and by Friday morning, all pipelines had active notices of varying degrees. Operationally, all pipelines appeared to be well prepared for the cold, and even on the morning of Friday, Dec. 23, reports from the pipelines indicated that line pack was high, systems were ready and that load had not yet begun to pick up significantly, particularly in eastern zones.

Figure 8 provides a summary of the pipeline restrictions that were in place from Dec. 14 through Dec. 31.

Figure 8. Interstate/Infrastructure Pipeline Restrictions



	Pipeline Notice
1	Restrictions on Non-Firm Contracts Customers with interruptible transportation contracts at higher risk of not being able to schedule adequate pipeline capacity
2	Ratable Take Requirement Pipeline requiring customers to supply and burn gas at uniform hourly rates to avoid excessive pressure fluctuations
3	Critical Day (Transport Deliveries/Storage Withdrawals) Pipeline requiring customers to stay within their transportation and storage contractual requirements
4	Action Alert (Daily Balancing) Requires customers to ensure that their supply and demand is balanced at the end of each 24-hour gas day within the tolerances provided by the pipeline Tariff provisions
5	Phase 1 Cold Weather Advisory Alerting customers of pending cold temperatures and tightening system conditions
6	Phase 2 Cold Weather Extreme Conditions Requires customers to abide by their specific contract and rate provisions and to burn gas on a uniform hourly basis as their contracts direct; interruptible contracts at greater risk of having service cut
7	Daily Balancing OFO Requires customers to ensure that their supply and demand is balanced at the end of each 24-hour gas day within the tolerances provided by the pipeline Tariff provisions
8	Force Majeure Declared when there an event outside of the pipeline's control occurs that may render service unavailable to certain customers regardless of contractual arrangements (e.g., loss of compressor station)
9	Loss of Upstream Supply As a result of less gas coming into the pipeline due to upstream supply failures, pipelines provide notice that risk of downstream pressure loss and customer nomination cuts are increasing.

On the gas commodity supply side, nearly all of the natural gas consumed by generation in PJM originates in the Marcellus and Utica shale in the Appalachian region. Historically, loss of supply due to gas production well freeze-offs during cold snaps has not been as severe as compared to gas basins in the south central and southwestern United States. This was confirmed during outreach with a sample of producers after Winter Storm Uri in February 2021. While Uri did not have a major direct impact on PJM, there was a desire to get out ahead of the issues to determine if the supply losses experienced during Uri could occur in the Appalachian region. The feedback from those producers indicated that gas production and midstream processing and transport were much more hardened against cold temperatures compared to the same facilities in the south and southwest. Typical losses due to well freeze-off conditions range from around 2 to 3 Bcf (billion cubic feet) per day in the Appalachian region and this was the general assumption going into Elliott. In the end, the actual supply loss was closer to 10 Bcf, which significantly challenged the ability for natural gas-fired resources to procure fuel, likely leading to a portion of the outages on these resources.

It is important to note that while PJM coordinates with the natural gas industry prior to and during events such as Winter Storm Elliott, the tools used by PJM system operators to commit and dispatch resources relies on the availability and

offer data submitted for each generator. If the generator availability and offer data is not consistent with the resource's true capability, PJM operators are left with an inaccurate view of the true capability of the fleet.

Day-Ahead Market and Reliability Assessment Commitment Results

The PJM Energy Market consists of two markets: a Day-Ahead Market and a Real-Time Market. Two days prior to an operating day, PJM begins to set up the conditions, such as the expected outages and conditions for the operating day, in the model for the Day-Ahead Energy Market. (The two-settlement market mechanism is described in more detail in Appendix A.)

The Day-Ahead Market is cleared so that the cost to serve demand (physical and virtual) is minimized, while respecting the physical operating limits of the transmission system. Commitments in the Day-Ahead Market are financially binding on participants. Any differences between day-ahead commitments and what occurs in the operating day is addressed in the Real-Time Market. The PJM Day-Ahead Market utilizes the bid-in load from the Load Serving Entities, as well as virtual bids from Market Participants.

Capacity resources are required to offer into the Day-Ahead and Real-Time markets with accurate reporting of their availability and unit parameters, which include but are not limited to, start time, ramp rate, and minimum output and maximum output. In addition, resources can and do update their offers in both of these markets to reflect their actual fuel and operating costs.

For each operating day, PJM performs reliability analysis and develops an operating plan. PJM performs two reliability analyses a day ahead of the operating day. The first analysis, performed by the PJM reliability engineers, is an input into the PJM Day-Ahead Market performed prior to closing at 11:00. The second reliability analysis, called Reliability Assessment Commitment (RAC), is performed after the Day-Ahead Market clears and includes the commitments made in the Day-Ahead Market. After 16:15, PJM begins the RAC run, which commits adequate generation to meet the PJM forecasted demand plus reserves, while minimizing start-up and no-load cost. The focus of this commitment is reliability, and the objective is to minimize start-up and no-load costs for any additional resources that are committed. Using the most up-to-date weather forecast, load forecast, transmission facility and generator availability, and other information, PJM commits additional generation, if necessary, to satisfy both expected loads and the needed reserves for the operating day. This includes scheduling additional resources during the operating day that did not have a Day-Ahead Market commitment. PJM scheduled 4,411 MW of combustion turbines (CTs) between Dec. 23 and Dec. 24.

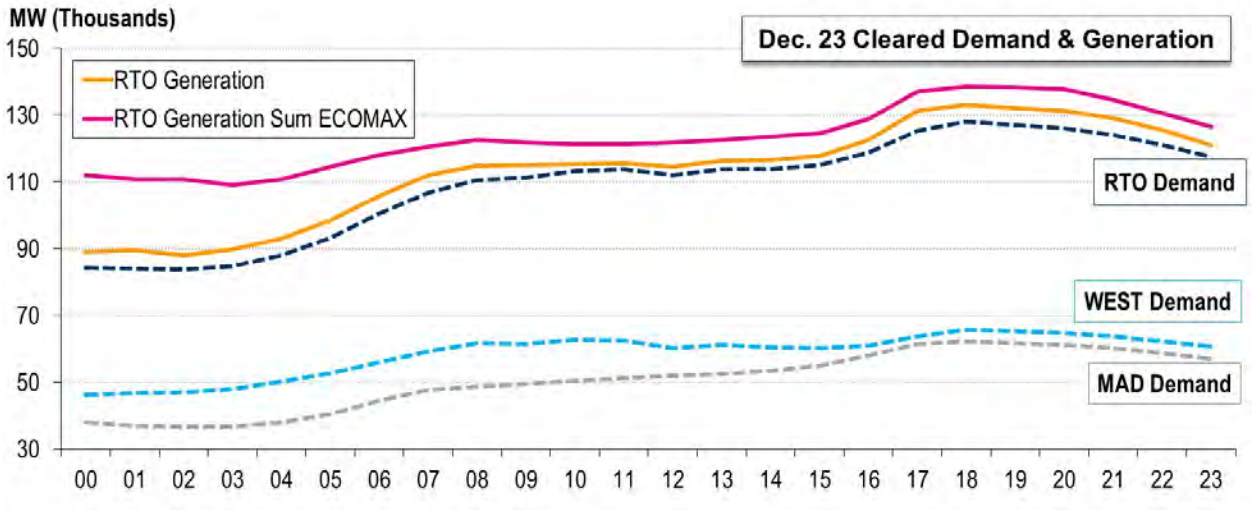
PJM also performs additional reliability analysis to confirm transmission facilities are operated within their equipment limits when committing generation. During severe winter weather events, PJM communicates extensively with both Generation Owners and gas pipeline operators to adequately understand the likelihood that natural gas-fueled generators are able to procure the gas needed to operate. PJM may perform additional resource commitment runs, as necessary, based on updated PJM load forecasts and updated resource availability information. It is important to note that these resource commitment runs use available offer data submitted into Markets Gateway by Generation Owner/operators. If the offer information is not accurate, the commitment results and operating plan PJM develops may be inadequate. Following these commitment runs, PJM sends out individual generation commitment updates to specific Generation Owners only.

The outcome of all of these processes is a set of resource commitments expected to be able to maintain reliability during the operating day.

Dec. 23

PJM's Dec. 23 operating day plan was prudent, given the expected. PJM scheduled the system such that almost 29,000 MW of reserve capacity was available to meet load and generation contingencies, and to support neighboring systems, according to the information submitted by Market Participants. Figure 9 presents the cleared day-ahead demand, and the generation committed to meet that demand, plus reserves for Dec. 23 operating day.

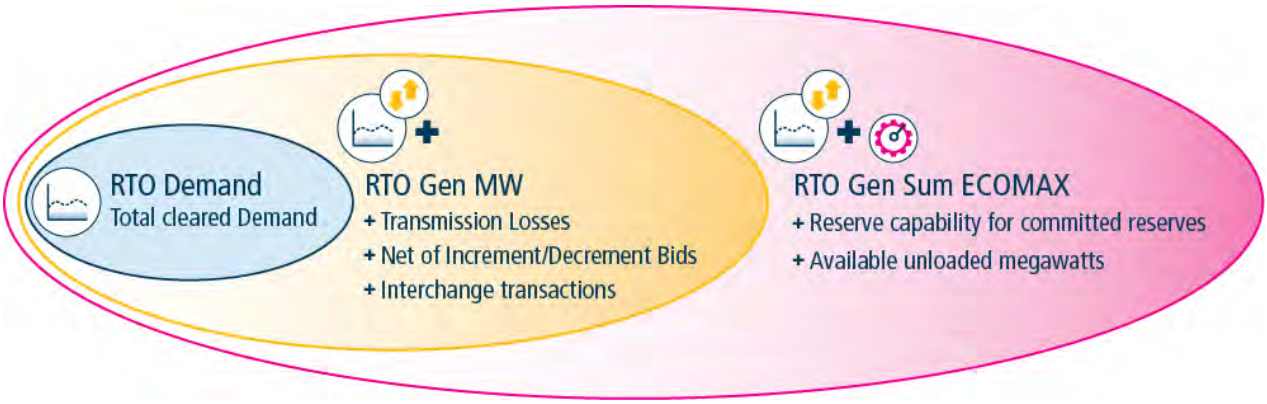
Figure 9. Dec. 23 Cleared Demand and Generation from Day-Ahead Market



In Figure 9:

- RTO Demand is the total cleared demand in the Day-Ahead Market, which includes fixed demand and cleared price-sensitive demand. The RTO Demand is not the same as the PJM Load Forecast.
- RTO Gen MW is the total generation megawatts loaded (or cleared) in the Day-Ahead Market. It includes all cleared generation. This value is greater than the RTO Demand because it accounts for transmission losses, the net of increment and decrement bids, and interchange transactions in or out of the PJM Balancing Authority.
- RTO Gen Sum ECOMAX is the total sum of all online generation resource's economic maximums committed in the Day-Ahead Market. This value is larger than the RTO Gen MW because it includes reserve capability for committed reserves and unloaded megawatts not explicitly needed in the clearing process but are available due to the mix of resources committed in the Day-Ahead Market.

Figure 10. Cleared Demand & Generation Representation



For the Dec. 23 operating day, the Day-Ahead Market committed 133,165 MW of generation for energy (yellow line in Figure 9), with 5,474 MW of unloaded generation (magenta line in Figure 9), including approximately 11,000 MW of combustion turbines (CTs) scheduled economically and 1,270 MW committed for reliability purposes to control constraints. PJM also scheduled an additional 3,168 MW in the RAC runs. In addition, there was another approximately 16,000 MW in CTs available for dispatch in real time that were not committed in the Day-Ahead Market.

Entering the operating day on Dec. 23, PJM had approximately 158,000 MW of operating capacity with a projected peak load of around 127,000 MW. Based on the Day-Ahead Market results, PJM did not anticipate the need to run a significant amount of additional CTs on Dec. 23 or Dec. 24. However, as more and more generating resources started to report their unavailability to PJM during the evening peak on Dec. 23 and through the early morning hours of Dec. 24, PJM Dispatch began scheduling additional CTs to come online.

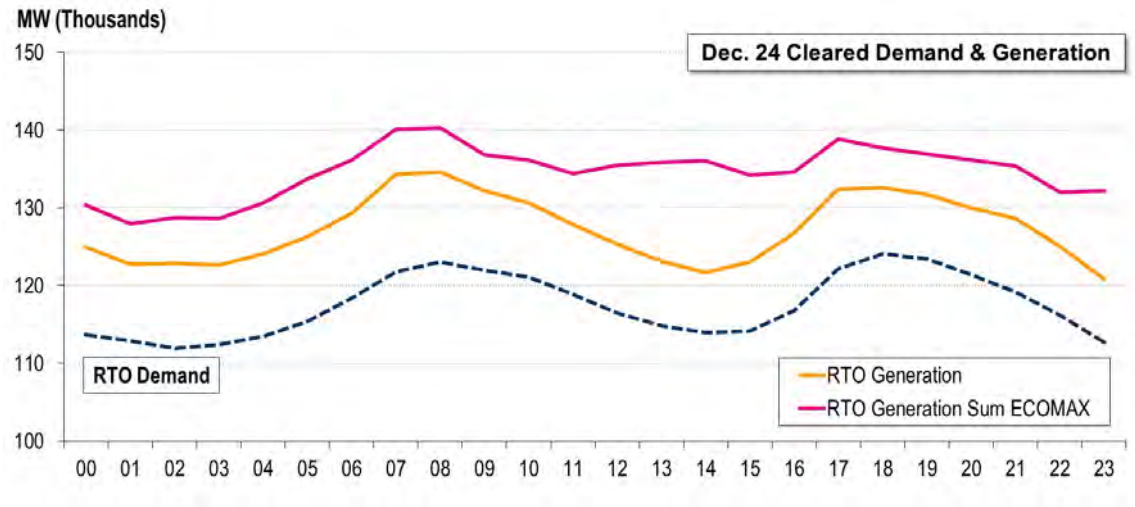
As early as Dec. 20, generation resource operating limitations and minimum operating, design or performance temperature were submitted to PJM in advance of the cold weather event after PJM declared a Cold Weather Advisory. All of the generator-submitted data was taken into consideration, with PJM forecasting a significant surplus of generation leading into the Dec. 23 operating day. This included accounting for a historical average of generator forced outages through cold weather events. As such, PJM did not declare a Unit Startup Notification Alert or commit any long lead generation or recall maintenance outages to meet capacity forecasts. As described in the Operating Day section of this report, in 92% of cases where generators failed to perform, PJM either had little or no notice, and very few resources provided updated parameters to reflect fuel supply constraints or other unit issues.

Dec. 24

Prior to the operating day of Dec. 24, PJM issued a Cold Weather Advisory on Dec. 20 for the period of Dec. 23 to 26. PJM then issued a Cold Weather Alert for the entire RTO on Dec. 23, effective for Dec. 24. The operating plan for Dec. 24 was updated based on operating conditions experienced on Dec. 23. Load forecasts were updated, and unit commitments' needs were updated based on generating resources that experienced forced outages throughout the day on Dec. 23.

Figure 11 presents the cleared day-ahead demand and committed generation to meet that demand, plus reserves for the Dec. 24 operating day.

Figure 11. Dec. 24 Cleared Demand & Generation from Day-Ahead Market



For Dec. 24, the Day-Ahead Market committed 134,615 MW of generation for energy (yellow line in Figure 11), with an additional 5,672 MW of unloaded generation (magenta line in Figure 11). PJM committed resources based on the RAC runs and for reliability. PJM also committed additional resources, based on unit availability and other parameters in Markets Gateway. In total, approximately 6,000 MW of additional capacity for Dec. 24 was committed, beyond what was committed in the Day-Ahead Market, to support the anticipated loads and reserve requirements. In addition, there were another 9,500 MW in CTs available for dispatch in real time, as communicated by generators to PJM. This results in a total of approximately 155,700 MW in operating capacity for Dec. 24.

PJM system operators knew that there was going to be uncertainty in the load forecast as a result of the extreme weather. In addition to accounting for weather and load uncertainty, PJM scheduled additional reserve resources in anticipation of generator failures. Generation failures often increase somewhat during bitter-cold conditions – recent history indicates on the order of 5% to 10%. On Dec. 24, several generating resources were committed in the Day-Ahead Market but were not available in the operating day due to forced outages. The decision was therefore made to operate prudently by scheduling additional reserves. Generation performance, including generation resources that were committed in the Day-Ahead Market but were not available in the operating day, is presented in the Operating Day section of the report.

Utilizing these commitments, as well as the generator parameters of units that did not have Day-Ahead Market commitments, but were reporting to PJM as available with short notice, PJM anticipated that approximately 155,700 MW of generation would be available for Dec. 24.

Operating Day

The Operating Day section of the report details the events and actions PJM initiated during the operating days of Dec. 23 and Dec. 24 to maintain reliability and not shed load. It describes the emergency procedures issued and actions taken, the public Call for Conservation, the Disturbance Control Standard event, as well as the generation and Demand Response performance, real-time interchange, and gas availability issues.

On Dec. 23 and Dec. 24, PJM remained reliable, was able to serve its customers, and was able to support neighboring areas to the south and minimize the amount of load shed in these external areas. PJM reliably met the demand on both

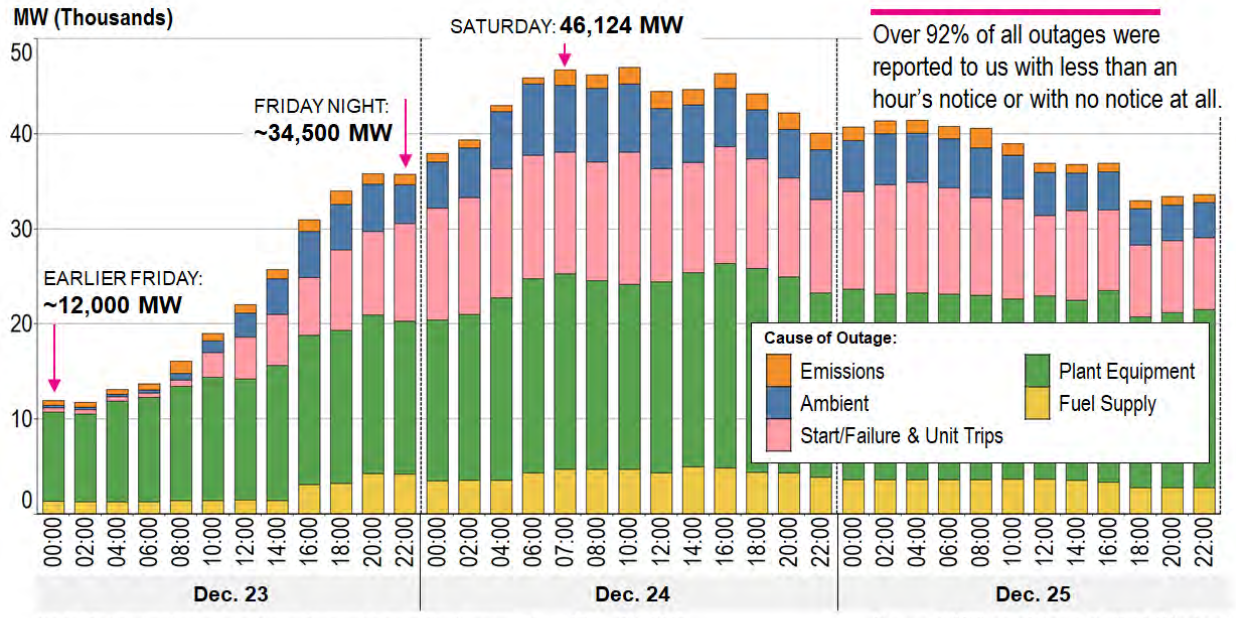
Dec. 23 and Dec. 24 by employing several emergency procedures and utilizing market signals to incent response from the supply and demand side resources. Although the 136,010[3] MW peak load on the evening of Dec. 23 was not one of PJM's top 10 peak winter load days, it essentially matched the forecasted 50/50 peak load for the 2022/2023 winter season (approximately 25,000 MW above an average winter day).

As described in the Advanced Planning section, going into the Dec. 23 operating day, PJM had over 158,000 MW of operating capacity with a projected peak load of around 127,000 MW, resulting in over 30,000 MW of reserves. Based on the Day-Ahead Market results, PJM did not anticipate the need to run a significant amount of additional generation on Dec. 23 or Dec. 24. However, as more and more generating resources started to report their unavailability to PJM during the evening peak on Dec. 23 and through the early morning hours of Dec. 24, PJM Dispatch began scheduling additional generators to come online.

Emergency Procedures Issued and Actions Taken During Dec. 23 and Dec. 24

As the extreme cold front moved into the PJM region throughout Dec. 23, the load shape looked more like a summer day, with a lower morning valley that ramped up throughout the day. Coincident with the increasing demand, PJM began experiencing rapidly increasing levels of forced generation outages, as shown in Figure 12. Additional information on generation performance is presented in later in this section.

Figure 12. Forced Outages by Cause



Note: Only even hours are shown for readability with the exception of Dec. 24, 2022, 07:00, which was the hour with the largest amount of forced outages and derates.

Source: GADS as of March 1, 2023. Wind and solar unit outages are not included in the data.

The conditions of Winter Storm Elliott led to PJM requesting the loading of Synchronized Reserve generation on five separate occasions during Dec. 23 and Dec. 24. Four of these events were called in response to a low Area Control Error (ACE) caused by increasing load and generation tripping and start failures. One of the events was called in direct response to the loss a generating unit. Five Synchronized Reserve Events over a two-day period is extremely unusual. All five of the events on Dec. 23 and Dec. 24 exceeded 10 minutes in duration, which is again extraordinary. Since the start of 2021, there have been 47 Synchronized Reserve Events, of which only 17 (36%) were more than 10 minutes in

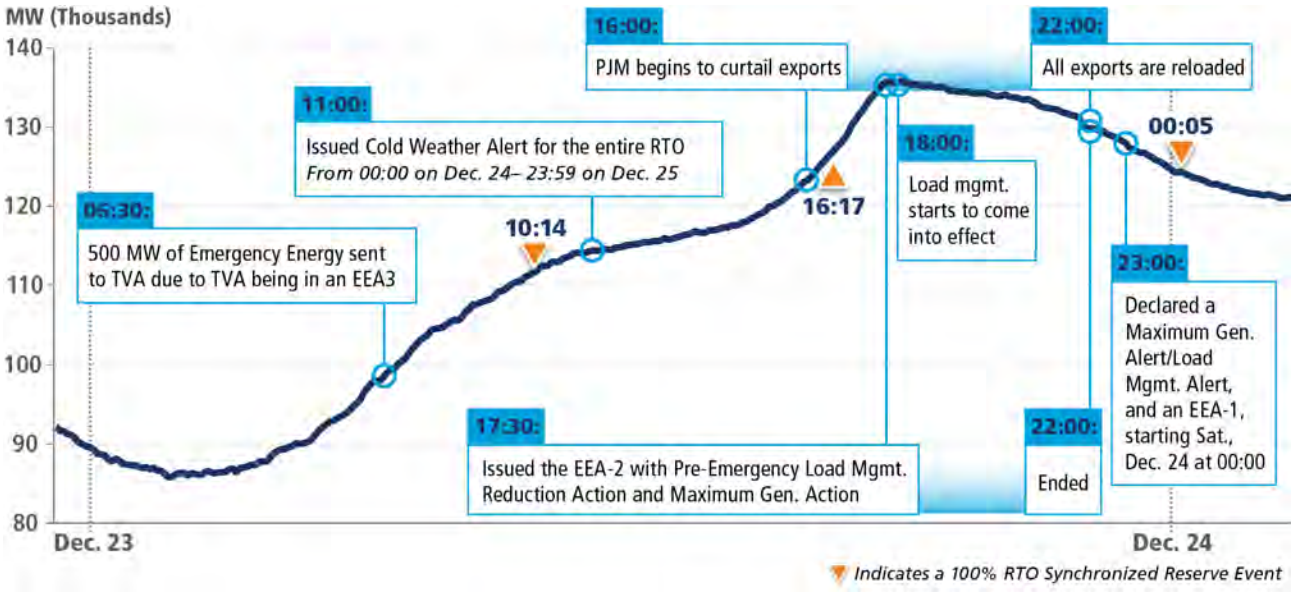
[3] The Dec. 23 peak of 136,010 MW incorporates Demand Response as part of the total.

duration, and five of these 17 occurred during Winter Storm Elliott. Additional information on Synchronized Reserve Events and Reserve performance is presented in the Markets Outcomes section of this report.

Dec. 23

PJM system operators initiated several actions on Dec. 23 as load continued to increase. Figure 13 presents the PJM emergency procedures initiated, as well as the PJM load and the Synchronized Reserve Events, for Dec. 23.

Figure 13. Dec. 23 Emergency Procedures



Early in the morning on Dec. 23, PJM was exporting energy to adjacent areas and tracking under the load forecast. At 06:30, PJM provided 500 MW of emergency energy to TVA, who had issued a NERC Energy Emergency Alert Level 3 (EEA3), which is issued when the Balancing Authority, in this case TVA, is unable to meet the minimum contingency reserves requirements. At 10:00 on Dec. 23, PJM conducted an SOS-Transmission call to inform Transmission Owners of anticipated system conditions and the operating plan for the day.

	Dec. 23 HE 05
Outages	13,449 MW
Interchange	7,517 MW
Load	88,237 MW

At 10:14 on Dec. 23, PJM deployed Synchronized Reserves to recover low ACE caused by increasing load combined with generation resources tripping offline and failing to start. At this time, total PJM reserves were approximately 1,500 MW. At 11:00 on Dec. 23, PJM issued a Cold Weather Alert for the entire RTO from 00:00 on Dec. 24 through 23:59 on Dec. 26.

Beginning around 14:00 on Dec. 23, generation continued to trip or fail to start at a rate of approximately 1,800 MW per hour. This posed a challenge for PJM's ability to deliver exports to neighbors. During this period, the operational situation was strained for a number of reasons:

	Dec. 23 HE 13
Outages	24,032 MW
Interchange	8,283 MW
Load	115,048 MW

- PJM's ACE was dropping and trending significantly below zero, indicating insufficient generation to support load due to generator outages and failures. PJM found that it was unexpectedly and rapidly exhausting its operating and Primary Reserves because of the unexpected generator outages.
- PJM had put generation resources on notice, through Advisories and Alerts, of PJM's need for them to be prepared to run. PJM relied on Generator Owner/operator-submitted data and believed these reserves were available. In

many cases, this data did not reflect the actual capability of the generator and PJM would only learn of the generation resource failures at the time PJM was expecting these resources to begin to run.

- A Disturbance Control Standard (DCS) event, discussed later in this report, was also unfolding during this same time period.

Late in the afternoon of Dec. 23, temperatures continued to drop rapidly, and load continued to increase very quickly. During this period of operational uncertainty and deteriorating system conditions, PJM took additional emergency steps it determined were necessary to preserve the reliability of the system. Despite margins being incredibly tight, no load was shed.

Shortly after 16:00, PJM began cutting non-firm exports, consistent with PJM Manual 13. Export transactions had been decreasing throughout the afternoon, but by 16:00, it was evident PJM could no longer support non-firm exports. Given the trends in ACE, the high outage rates being observed in real time, and the time it would take for the impacts of the capacity recalls to be known, PJM Dispatch believed capacity recalls alone were insufficient to stabilize the system.

	Dec. 23 HE 15
Outages	26,672 MW
Interchange	6,732 MW
Load	117,143 MW

While the export transactions were being curtailed, at 16:17, PJM entered into another Synchronized Reserve Event due to low ACE caused by increasing load and generation resources tripping and failing to start. PJM deployed Synchronized Reserves for almost two hours, before canceling at 18:09. Load was continuing to increase, and PJM had several additional generation resource trips throughout the Synchronized Reserve Event period. The PJM ACE did not recover until after Demand Response was implemented at 18:00.

Available Synchronized Reserves continued to drop as PJM began calling upon these resources for energy, with many failing to perform at expected levels. At times during this period, PJM was within 1,000 MW of its required Synchronized Reserve level of 1,667 MW. PJM dipped below this required Synchronized Reserve threshold for a portion of the hour ending 18:00 because it was deploying Synchronized Reserves but not getting the expected response.

At 17:30, ACE was very low at nearly -3,000 MW, and the load was continuing to grow. In response, PJM issued a NERC Energy Emergency Alert Level 2 (EEA-2[4]) with Pre-Emergency Load Management Reduction Action and Maximum Generation Action, directing generation resources to operate above their normal maximum output levels. An EEA-2 is issued to ensure all NERC Reliability Authorities understand the potential and actual PJM system emergencies and is typically issued when the following events have occurred: public appeals to reduce demand; voltage reduction; and interruption of non-firm load in accordance with applicable contracts, demand-side management, or utility load conservation measures (NERC Standard EOP-11).

	Dec. 23 HE 16
Outages	28,351 MW
Interchange	6,032 MW
Load	119,375 MW

Certain emergency warnings and actions trigger a Capacity Performance Assessment Interval (PAI). The issuance of the EEA-2 with Pre-Emergency Load Management Reduction Action and Maximum Generation Action triggered the first performance assessment event, requiring PJM to evaluate the performance of all resources located in the Emergency

[4] EOP-011 NERC Energy Emergency Alerts (EEAs):
EEA0 – No Energy Deficiencies
EEA1 – All Available Resources in Use or Anticipated to be In Use; triggered when PJM issues Maximum Generation Emergency Alert)
EEA2 – Load Management Procedures in effect; triggered when PJM issues Emergency Mandatory Load Management Reduction, Voltage Reduction Action, or Deploy All Resources Action (whichever is issued first)
EEA3 – Firm Load Interruption Imminent or in Progress; triggered when PJM issues Manual Load Dump Action

Action area for each applicable five-minute interval. The performance assessment events are described in more detail in the Markets Outcomes section of the report.

PJM also called for 30-minute and 60-minute Emergency Demand Response to be activated. The 30-minute Emergency Demand Response came into effect by 18:00, and the 60-minute Demand Response came into effect by 18:30. PJM did not call for the two-hour Demand Response resources, as these resources would not have been implemented until after the evening peak. Demand Response performance can be difficult to determine in real time due to the lack of visibility of the performance to the system operator. More information on the performance of Demand Response is described later in this section.

	Dec. 23 HE 18
Outages	33,040 MW
Interchange	1,527 MW
Load	130,856 MW

Generation resources continued to trip offline and fail to start, resulting in ACE trending low during the hour ending 18:00. Starting at 17:05, PJM called Northeast Power Coordinating Council (NPCC) for 1,500 MW of shared reserves. NPCC is made up of New York and the six New England states, as well as the Canadian provinces of Ontario, Québec and the Maritime provinces of New Brunswick and Nova Scotia. Shared Reserve Activation is a procedure between the NPCC and the PJM Mid-Atlantic Control Zone to jointly activate a portion of their 10-minute reserve following any of the following situations:

- Generation or energy purchase contingencies equal to or greater than 500 MW (300 MW for the Maritimes) occur under conditions where activation assists in reducing a sustained load/generation mismatch.
- Two or more resource losses below 500 MW (300 MW for the Maritimes) within one hour of each other
- Periods of significant mismatch of load and generation

The objective of Shared Reserve Activation is to provide faster relief of the initial stress on the interconnected transmission system.

Over the evening peak on Dec. 23, PJM attempted to commit additional generating units that reported to PJM as being available to schedule. PJM system operators also considered long-lead-time resources that were beyond the window to be requested to start, which totaled about 3,000 MW. Generator maintenance outages that were recallable totaled about 1,692 MW; however, these are only recallable with 72-hours' notice. (Note: if PJM determines that it must rescind its approval of a Generator Maintenance Outage of a Generation Capacity Resource that is already underway in order to preserve the reliable operation of the PJM region, PJM must provide the member at least 72-hours' advance notice.)

Following the peak at approximately 18:10, PJM began lifting export transaction curtailments. By 22:00, PJM exports had returned to full flow. (Additional information on the real-time interchange is presented later in this section.)

	Dec. 23 HE 22
Outages	36,054 MW
Interchange	3,274 MW
Load	133,096 MW

At 23:00, load began to slowly ramp down, leading PJM to cancel the EEA-2 and the Pre-Emergency Load Management Reduction action at 23:00, ending the first performance assessment event. In addition, at 23:00 on Dec. 23, PJM declared a Maximum Generation Alert/Load Management Alert for Dec. 24, which provides an early alert that system conditions may require the use of the PJM emergency procedures. This is implemented when Maximum Emergency generation is called into the operating capacity or if Demand Response is projected to be implemented. When PJM declares a Maximum Generation Alert/Load Management Alert:

- Member transmission and generation dispatchers are expected to review plans to determine if any maintenance or testing, scheduled or being performed, on any monitoring, control, transmission, or generating equipment can be

deferred or canceled. Transmission and generation dispatchers are expected to suspend any high-risk testing of generating or transmission equipment.

- Member generation dispatchers are expected to report to PJM Dispatch any and all resource-limited facilities as they occur via Markets Gateway and update PJM Dispatch. Member generation dispatchers are also expected to update the "early return time" for any planned generator outages as indicated in PJM Manual 10, Section 2.

PJM also issued a NERC Energy Emergency Alert Level 1 (EEA-1) starting Saturday, Dec. 24, at 00:00, indicating PJM foresees or is experiencing conditions where all available resources are scheduled to meet firm load, firm transactions, and reserve commitments and is concerned about sustaining its required contingency reserves.

Shortly before midnight on Dec. 23, PJM issued a Call for Conservation for the entire PJM footprint, asking consumers to scale back their energy use, where possible, between the hours of 04:00 on Dec. 24 and 10:00 on Dec. 25.

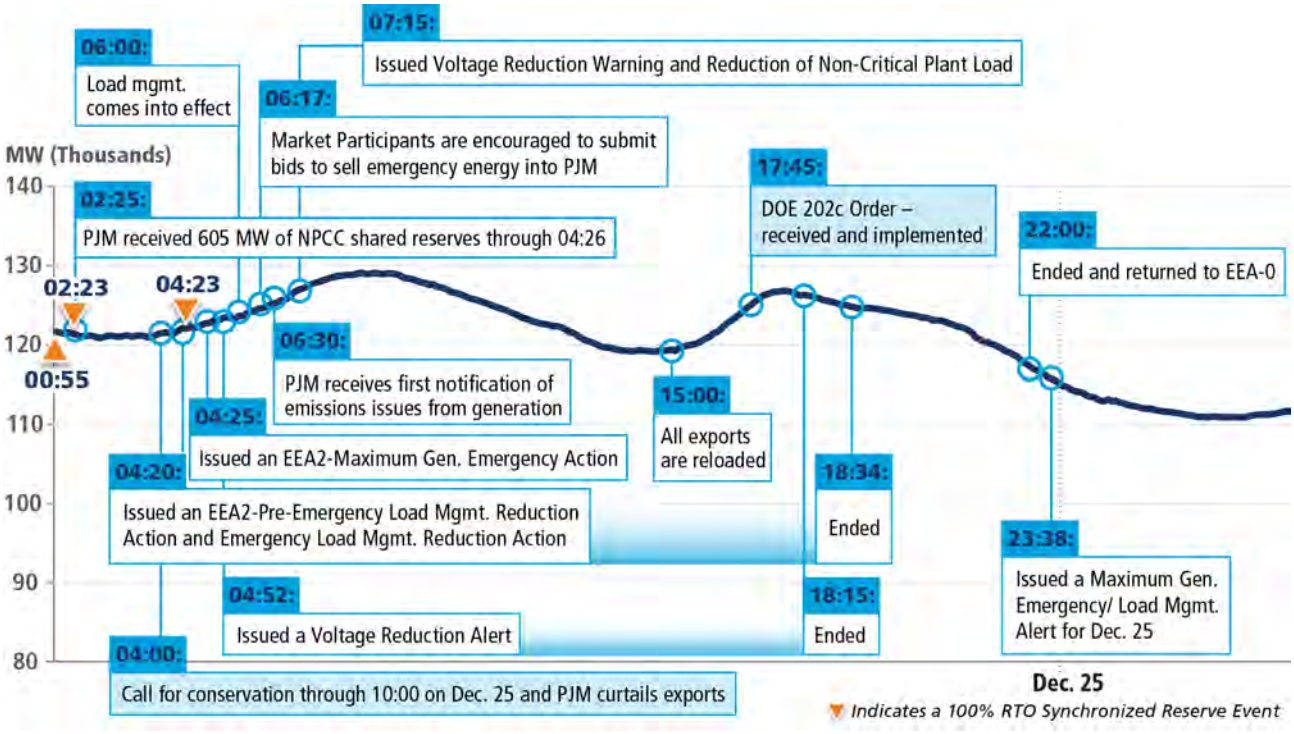
Dec. 24

The high demand for electricity continued after the peak on Dec. 23 and into the overnight period of Dec. 24. In addition to forced outages, approximately 6,000 MW of generators were called but were not online for their expected start time for the Dec. 24 morning peak, with the vast majority of these being gas-fired resources.

The high rates of generator outages also limited PJM's ability to replenish pond levels for pumped storage hydro prior to the morning peak on Dec. 24, leaving PJM with extremely limited run hours for pumped storage generation. Between forced outages, derates, generators not starting on time, and the inability to fill pumped storage hydro ponds, approximately 47,000 MW of the generation fleet in the PJM region was unavailable for the Dec. 24 morning peak. Additionally, the valley load during the early morning hours on Dec. 24 was atypically high. It was approximately 40,000 MW higher than the next-highest valley over the last decade.

PJM system operators took the several actions on Dec. 24 to maintain system reliability and serve load. Figure 14 presents the PJM emergency procedures issued, as well as the PJM load, for Dec. 24.

Figure 14. Dec. 24 Emergency Procedures



At 00:05 on Dec. 24, PJM deployed Synchronized Reserves due to low ACE caused by increasing load and generator trip and start failures. At 02:23, PJM deployed Synchronized Reserves again for approximately one hour to recover from another generation resource trip. At 02:25, PJM received 605 MW of NPCC shared reserves from 02:25 through 04:26. More information on the Synchronized Reserve Events is presented in the Markets Outcomes section of this report.

	Dec. 24 HE 01
Outages	38,368 MW
Interchange	4,604 MW
Load	124,757 MW

During a typical midnight period, load reduces, and PJM would operate pumped storage resources as pumps to fill their ponds so that they have the ability to generate for the upcoming peak. Operating a pumped storage resource in pumping mode increasing load on the system because electricity is consumed to operate the resource as a pump. Given the tight conditions, PJM was not able to pump at any of the pumped storage facilities prior to the morning peak. This left PJM with extremely limited run hours for pumped storage generation. As previously stated, going into the morning peak on Dec. 24, resource unavailability was approximately 47,000 MW, including the unavailability of pumped storage hydro generation.

At 04:20 on Dec. 24, PJM issued an EEA-2 – Pre-Emergency Load Management Reduction Action and Emergency Load Management Reduction Action. In this case, PJM dispatched all Load Management, starting with long lead (120 minute) at 04:20, short lead (60 minute) at 05:00, and quick lead (30 minute) at 05:30. Demand Response performance is described later in this section.

At 04:23, PJM deployed Synchronized Reserves again due to low ACE caused by increasing load and generation resources tripping and start failures. And then at 04:25, PJM issued an EEA-2 – Maximum Generation Emergency Action and began to load Maximum Emergency generation. This triggered the Dec. 24 PAI event. When PJM issues a Maximum Generation Emergency Action:

	Dec. 24 HE 03
Outages	40,243 MW
Interchange	3,322 MW
Load	121,487MW

- Member generation dispatchers are expected to report to PJM all resource-limited facilities as they occur in Markets Gateway and update PJM Dispatch. Generation dispatchers also suspend regulation and load all units to the Maximum Emergency generation level and then notify PJM Dispatch of any Maximum Emergency generation load prior to PJM requested Maximum Emergency generation is loaded.
- Non-Retail Behind-the-Meter Generation (NRBMG) is also loaded. NRBMG performance is described later in this section.

At 04:52, PJM issued a Voltage Reduction Alert. A Voltage Reduction Alert notifies members that a voltage reduction may be required during a future critical period. This alert is issued when the estimated Operating Reserve capacity is less than the forecasted Synchronized Reserve requirement. When PJM issues a Voltage Reduction Alert:

- Member generation dispatchers are expected to order all generating stations to curtail non-critical station light and power.
- Member transmission dispatchers and distribution providers (DPs) are expected to prepare to reduce voltage, if requested.
- Member transmission dispatchers/DPs and curtailment service providers (CSPs) are expected to notify appropriate personnel that there is a potential need to implement load management programs, in addition to interrupting their interruptible/curtailable customers in the manner prescribed by each policy, if it has not already been implemented previously.
- Market Participants are expected to remain on heightened awareness regarding PJM system conditions and the potential need for Emergency Energy Purchases.

At 06:17, PJM requested bids for emergency energy and PJM also repeated a public appeal to conserve energy. Note: PJM did not load emergency imports on Dec. 24.

	Dec. 24 HE 06
Outages	46,036 MW
Interchange	1,437 MW
Load	122,172 MW

At 07:15, PJM issued a Voltage Reduction Warning and Reduction of Non-Critical Plant Load, warning members that the available Synchronized Reserve is less than the Synchronized Reserve Requirement and that present operations have deteriorated such that a voltage reduction may be required.

At 07:30, PJM conducted an SOS-Transmission conference call with the PJM Transmission Owners to update their leadership on the situation and indicated PJM was in a very critical operating period, with the potential that PJM may need to shed load. Another SOS-Transmission conference call took place at 10:00.

As PJM approached the morning peak, PJM was a net importer of energy. TVA and Duke were both in an EEA-3 and shedding load. PJM was unable to provide assistance to TVA and Duke, and PJM was receiving assistance primarily from NYISO.

Forced outages of generation continued to increase through the morning peak on Dec. 24, with an estimated level of 41,000 MW of outages and 200 unit trips. Factoring in a number of reserve generators (units that are offline and available – that are called if needed) that missed scheduled start times Saturday morning or operated at less than capacity, combined with PJM's inability to replenish pumped storage based on the lack of availability of generators overnight, PJM was missing approximately 47,000 MW of the generation fleet by the morning peak of Dec. 24, the coldest day of the holiday weekend.

The morning peak for Dec. 24 was approximately 130,000 MW, occurring at 08:30.

As the morning peak was occurring, it was reported to PJM that several generators may need to come offline at or around the evening peak due to emissions restrictions. At this point, PJM contacted the U.S. Department of Energy (DOE) and held several calls to discuss the concerns and options available to ensure the units could remain online if needed. PJM also began outreach to state utility commissions and environmental agencies in states where there was a potential to operate units under a DOE Emergency Order.

Heading into Saturday evening, there was still uncertainty about resource performance. To mitigate the risk of generators coming offline due to emissions limitations, PJM submitted a petition to the DOE Saturday afternoon. At 17:30, the DOE issued an emergency order under Section 202(c) of the Federal Power Act, determining that an electric reliability emergency existed within the PJM region that required intervention by the United States Secretary of Energy to keep the power flowing.

The emergency order was effective Dec. 24 through 12:00 on Dec. 26. The order authorized all electric generating units serving the PJM footprint to operate up to their maximum generation output levels under limited, prescribed circumstances, even if doing so exceeded their air quality or other permit limitations.

Two generating units that fell under the order ran at levels that exceeded a condition in their operating permit. The Department of Energy requires PJM to identify those generators, which were Bethlehem Energy in Bethlehem, Northampton County, Pennsylvania, and York Energy 1 in Peach Bottom Township, York County, Pennsylvania. On Dec. 24, PJM communicated the need to operate these units under the DOE emergency order to the Pennsylvania Department of Environmental Protection. In accordance with the DOE's requests, PJM followed up with communications to the local communities where the plants are located through local media outlets.

The evening peak for Dec. 24 was approximately 136,000 MW. Following the evening peak, PJM started to cancel emergency procedures. At 18:15, PJM canceled the Voltage Reduction Warning and the Reduction of Non-Critical Plant Load. At 18:34, PJM canceled the Voltage Reduction Alert.

	Dec. 24 HE 17
Outages	47,310 MW
Interchange	3,607 MW
Load	120,183 MW

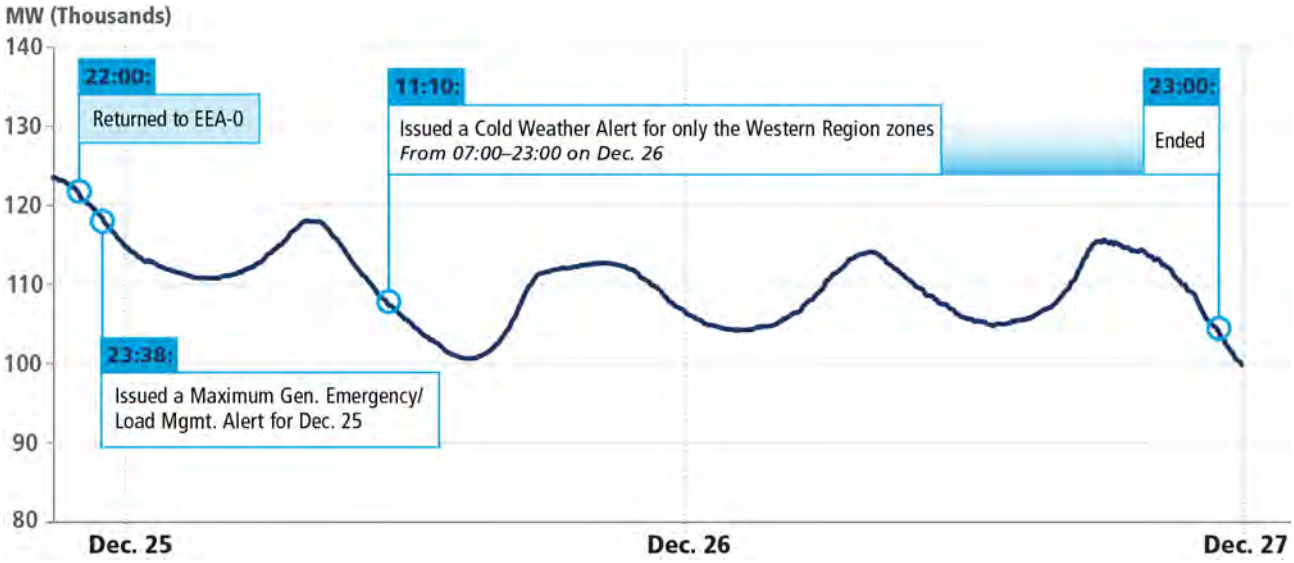
At 22:00 on Dec. 24, PJM canceled the Max Emergency Generation Action. This ended the Dec. 24 PAI. Around 22:00, the Demand Response ended, and PJM backed out of the EEA-2, indicating PJM was able to meet its load and Operating Reserve requirements. PJM's Call for Conservation also ended at this time.

At 22:38 on Dec. 24, PJM issued a Max Emergency Generation Alert for Dec. 25, resulting in PJM going into Dec. 25 in an EEA-1.

Dec. 25 and Dec. 26

On Dec. 25, a Sunday, PJM still had very high loads for a Christmas operating day. The morning peak was approximately 117,000 MW. There was sufficient capacity available to meet this morning peak as well as the evening peak, and PJM returned to EEA-0 at 22:00. Figure 15 presents the PJM emergency procedures, as well as the load for Dec. 24 at 22:00 to Dec. 26 at 23:00.

Figure 15. Dec. 25 and Dec. 26 Emergency Procedures



At 11:10 on Dec. 25, PJM issued a Cold Weather Alert for the Western Region zones only from 07:00 Dec. 25 to 23:00 Dec. 26. At 23:00 on Dec. 26, the Cold Weather Alert ended.

Figure 16 summarizes the emergency alerts, warnings and actions PJM implemented from Dec. 23 through Dec. 26.

Figure 16. Summary of Alerts, Warnings, and Actions Issued on Dec. 23, Dec. 24 and Dec. 25

Action Warning Alert Advisory

MESSAGE TYPE	DEC. 20	DEC. 21	DEC. 22	DEC. 23	DEC. 24	DEC. 25
Cold Weather Advisory			1	1	1	1
Cold Weather Alert				1	1	1
Emergency Load Mgmt Reduction Action				2	3	
Maximum Generation Emergency Action				1	1	
Maximum Generation Emergency/Load Management Alert				1	2	1
Non-Market Post Contingency Local Load Relief Warning	1	1		2	2	1
Post Contingency Local Load Relief Warning	3	3	1	25	26	6
Pre-Emergency Load Mgmt Reduction Action				2	3	
Synchronized Reserve Event				2	3	
Maximum Generation Emergency/Load Management Alert					1	
Voltage Reduction Warning and Reduction of NCPL					1	

As outlined in PJM Manual 13, Section 2.3: Capacity Shortages, "PJM dispatchers have the flexibility of implementing the emergency procedures in whatever order is required to ensure overall system reliability. PJM dispatchers have the flexibility to exit the emergency procedures in a different order than they are implemented when conditions necessitate." As such, PJM Operations evaluated the usage and combination of any and all emergency procedures during Winter Storm Elliott in order to best maintain overall system reliability. While many emergency procedures were issues by PJM throughout the event, some were considered and ultimately not issued.

- Cold Weather Alert – While a Cold Weather Advisory was issued for the entire PJM RTO on Dec. 20 for the operating period of Dec. 23–26, PJM Operations did not declare a Cold Weather Alert for the entire RTO until the Dec. 24 operating day, opting only to declare a Cold Weather Alert for the Western PJM zones for the Dec. 23 operating day. PJM Operations forecasted the potential for cold weather starting on Dec. 23 and, as such, issued the appropriate advisory, while continuing to monitor forecasted temperatures leading up to the operating day. Per PJM Manual 13, Section 3.3.2 Cold Weather Alert, "as a general guide, PJM can initiate a Cold Weather Alert across the RTO or on a Control Zone basis when the forecasted weather conditions approach minimum or actual temperatures of 10 degrees Fahrenheit or below." Outside of the Western zones, temperatures were never forecasted to reach near a minimum of 10 degrees and instead were expected to be several degrees higher at their minimum. As such, it was not appropriate to issue a Cold Weather Alert for the zones outside of the PJM Western footprint until Dec. 24 when the trigger temperatures were forecasted.
- Deploy All Resources Action – The Deploy All Resources Action is a unique emergency procedure with a unique application. Its purpose is to immediately load all available generation and Demand Response following a severe system disturbance to attempt to halt frequency decay. This could lead to unintended loss of system control with regard to energy balance. It is only expected to be used as a means of last resort. This specific emergency procedure was discussed by PJM Operations and decided against implementing for several reasons, as implementing a Deploy All Resource Action could have aggravated some of the thermal and voltage constraints that were being managed. In addition, PJM Operations was manually controlling the output of all pumped hydro facilities during the event. Issuance of this emergency procedure would have removed PJM's controlling ability of these resources and instead would have immediately depleted the pond levels, which were needed to be precisely managed through the event.
- Manual Load Dump Warning, Voltage Reduction Action & Manual Load Dump Action – These three steps constitute the most severe emergency procedures that can be utilized to maintain reliability. While PJM Operations has these steps in the queue to issue, as necessary, system conditions never dictated a need to utilize them. During a conference call held with PJM Transmission Owners at 07:30 on Dec. 24, prior to the most challenging system conditions of the event, which was the Saturday, Dec. 24, morning peak, PJM management made a clear statement for the Transmission Owners to be prepared to respond as quickly as possible to any or all of these emergency procedures as there was the possibility that they could be issued imminently. PJM Operations kept the Voltage Reduction Action in reserve to deploy, if additional generation tripped offline. Per PJM Manual 13, this would have been approximately 1.3% of the RTO load at the time. If a Voltage Reduction Action were issued, it would have been immediately followed with a Manual Load Dump Warning and EEA-3 declaration, as a Manual Load Dump would have been the only remaining emergency procedure to maintain reliability. Then, if required, PJM would have been prepared to issue a Manual Load Dump Action. PJM was ultimately able to maintain reliability through the event without issuance of these three emergency procedures.

Disturbance Control Standard Event

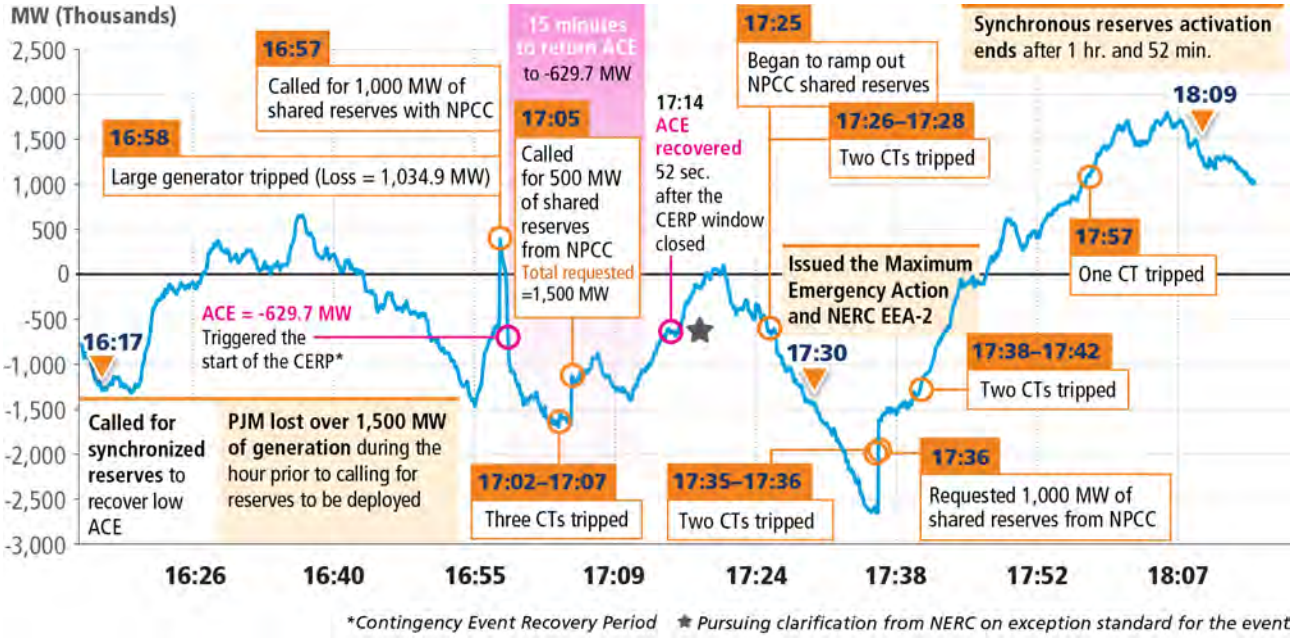
The purpose of the NERC Standard BAL-002, Disturbance Control Performance, is to ensure that PJM, a NERC Balancing Authority, is able to utilize its contingency reserve to balance resources and demand, and to return interconnection frequency to within defined limits following a Reportable Disturbance. NERC defines a Reportable Disturbance as any event that causes an Area Control Error (ACE) change greater than or equal to 80% of a Balancing Authority's or reserve sharing group's most severe contingency. ACE is a measure of how well the Balancing Authority is matching generation to the load. If load and generation are perfectly balanced, the ACE is zero. When a generator within

a Balancing Authority trips offline, the ACE goes down, and can go negative if it was already not above zero by a quantity at least as great as the output of the generator when it tripped. Because generator failures are far more common than significant losses of load and because contingency reserve activation does not typically apply to the loss of load, the application of Disturbance Control Standard (DCS) is limited to the loss of supply and does not apply to the loss of load.

PJM is required to have access to or operate with resource reserves to respond to disturbances. These reserves may be supplied from generation, controllable load, or coordinated adjustments to interchange schedules. The DCS Standard requires PJM to satisfy disturbance recovery criterion within a certain disturbance recovery period for 100% of Reportable Disturbances. The criterion requires PJM to return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE values just prior to the disturbance, a return of ACE is made to its pre-disturbance value. In either case, the disturbance recovery period is 15 minutes after the start of a Reportable Disturbance. Subsequently, PJM must fully restore the Synchronized Reserve within 90 minutes. All contingency losses (i.e., disturbances) with the lesser of 900 MW in the Eastern Interconnection or 80% of the Most Severe Single Contingency must be calculated and reported.

As described below, PJM was not able to recover the ACE within the prescribed 15 minutes. Figure 17 presents PJM's ACE on the evening of Dec. 23 during the DCS event:

Figure 17. ACE During DCS



Heading into the evening peak on Dec. 23, load was increasing rapidly and PJM was ramping the generation fleet to keep up with the increasing load. Load was increasing quicker than PJM was able to ramp generation, and, as a result, the PJM ACE started to go negative. By 16:17 on Dec. 23, ACE was trending at around negative 1,000 MW, indicating low capacity. In response, PJM called for Synchronized Reserves to be loaded to recover from the low ACE. After approximately ten minutes, the ACE partially recovered but, by 16:40, went negative again. By 16:55, the ACE was approximately negative 1,500 MW. At 16:57, PJM called for 1,000 MW of shared reserves from NPCC. At that point, PJM's ACE was 429 MW as a result of PJM deploying reserves for approximately 40 minutes.

Approximately one minute following PJM's call for shared reserves from NPCC, a large generator in PJM tripped, losing approximately 1,035 MW. The Generation Owner reported that the generator was loaded at 850 MW at the time the unit tripped. The loss of this large generation resource was the initiating event with respect to the BAL-002 standard reporting event. Prior to the unit tripping, PJM's ACE was negative 630 MW. After the unit tripped, PJM's ACE dropped below negative 1,500 MW. Per the BAL-002 standard, PJM is required to recover ACE to negative 630 MW within15 minutes.

PJM had been deploying reserves since 16:17. Load on the system was continuing to increase. Between 17:02 and 17:07, additional generation tripped, and, as a result, the ACE continued to decline to approximately negative 1,600 MW. At 17:05, PJM called for an additional 500 MW of shared reserves from NPCC, bringing the total shared reserves from NPCC to 1,500 MW.

By 17:14, the PJM ACE had recovered back to negative 630 MW, ending the DCS event 15 minutes and 52 seconds after the large generator tripped. Although the DCS event had technically ended, controlling the ACE continued to be a challenge. As reflected in Figure 17, the PJM ACE climbed back to around zero about five minutes later but then went negative again. Throughout all of this, PJM continued to deploy reserves and was ramping whatever resources were online and available.

At 17:25, PJM started to ramp out the shared reserves from NPCC, which can only be relied upon for 30 minutes (recall PJM called for shared reserves at 16:57). As load continued to increase and additional generation was lost, the PJM ACE was approaching negative 3,000 MW by 17:34.

At 17:36, PJM requested 1,000 MW of shared reserves from NPCC again, which helped the ACE to begin to recover. The ACE continued to recover until 18:09, at which time PJM ended the call for Synchronized Reserves to be loaded, 1 hour and 52 minutes after PJM began deploying them.

During this period, PJM was ramping generation as quickly as possible and deploying Synchronized Reserves for almost two hours. By 18:00, the rate that the load was increasing slowed as PJM was beginning to see the impact of the Demand Response that was called at 17:30.

PJM evaluated compliance with the BAL-002 standard, and engaged in communications with ReliabilityFirst regarding the matter. This evaluation included the consideration that BAL-002-3 R1.3 provides scenarios in which Responsible Entities are not subject to compliance with BAL-002-3 R1.1, provided certain thresholds are met.

In response to the low response rate and lack of available reserves, PJM will be reviewing procedures to identify triggering conditions that will further increase the amount of reserves that are scheduled leading into the operating day. This will include triggers to potential increase the amount of the Synchronized, Primary and/or Operating Reserves scheduled in the Day-Ahead, RAC and Real-Time market clearing.

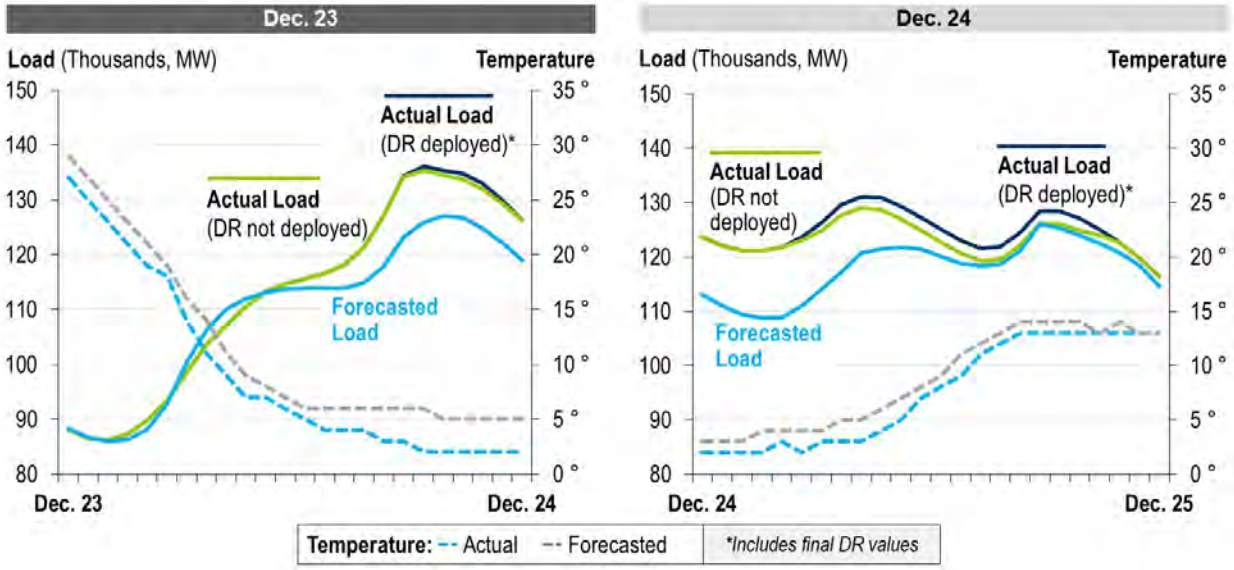
Load Forecast Versus Actual Load

The load forecasts for Dec. 23 and Dec. 24 presented a unique set of challenges. The winter holiday period has historically been a challenging time to forecast due to school vacations, business closures and atypical human behavior patterns, as presented in Figure 19. In the past, over-forecasting was more of an issue than under-forecasting, resulting in the PJM forecast team enhancing processes in recent years to correct for this over-forecasting trend. The winter 2022 holidays were further complicated by the extreme weather and Christmas Eve occurring on a Saturday, which had not occurred since 2016.

On Dec. 23, the forecasted peak load was 126,968 MW, and the actual peak was 136,010 MW, which included Demand Response added back into the load. On Dec. 24, the forecasted peak load was 121,723 MW, and the actual peak was

131,113 MW, which included Demand Response added back into load. On both Dec. 23 and Dec. 24, the actual load came in well higher than forecast, as presented in Figure 18.

Figure 18. Dec. 23 and Dec. 24 Actual Load



The high demand for electricity continued after the peak on Dec. 23 and into Dec. 24. The actual valley load, or low point of demand, on Dec. 24 was significantly greater than originally forecasted as well. The Dec. 24 valley load was higher than any other peak, or high point of demand, for that date over the previous decade, as shown in Figure 19, which presents the holiday load for 2022 and the previous 10 years.

Figure 19. Holiday Load for Previous 10 Years

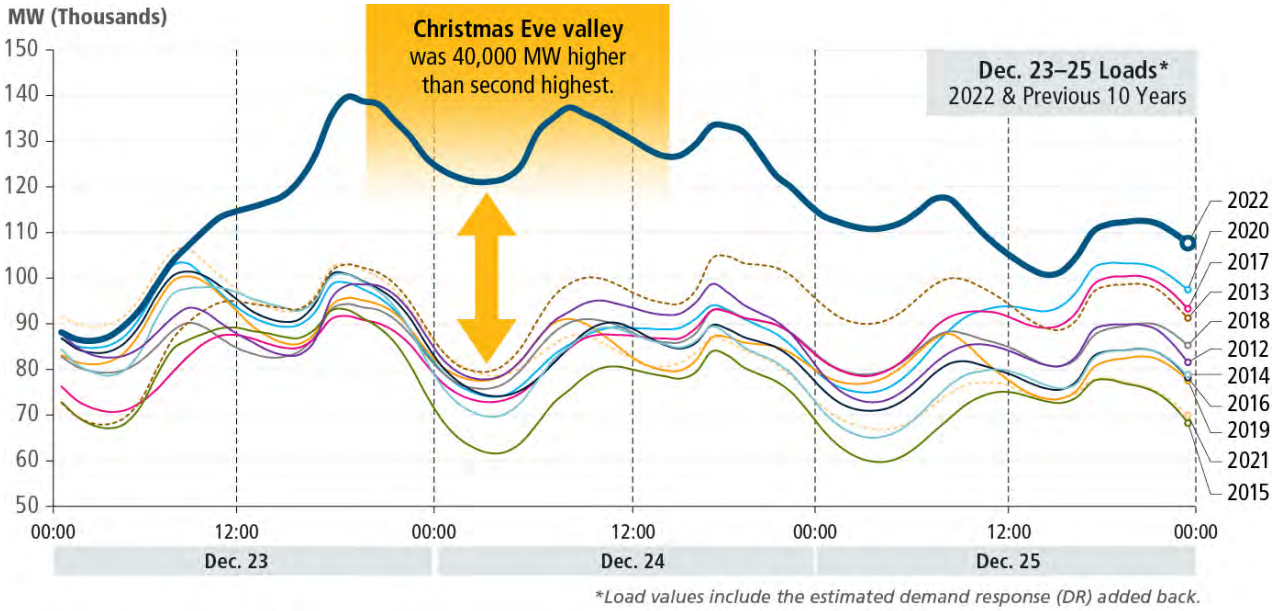
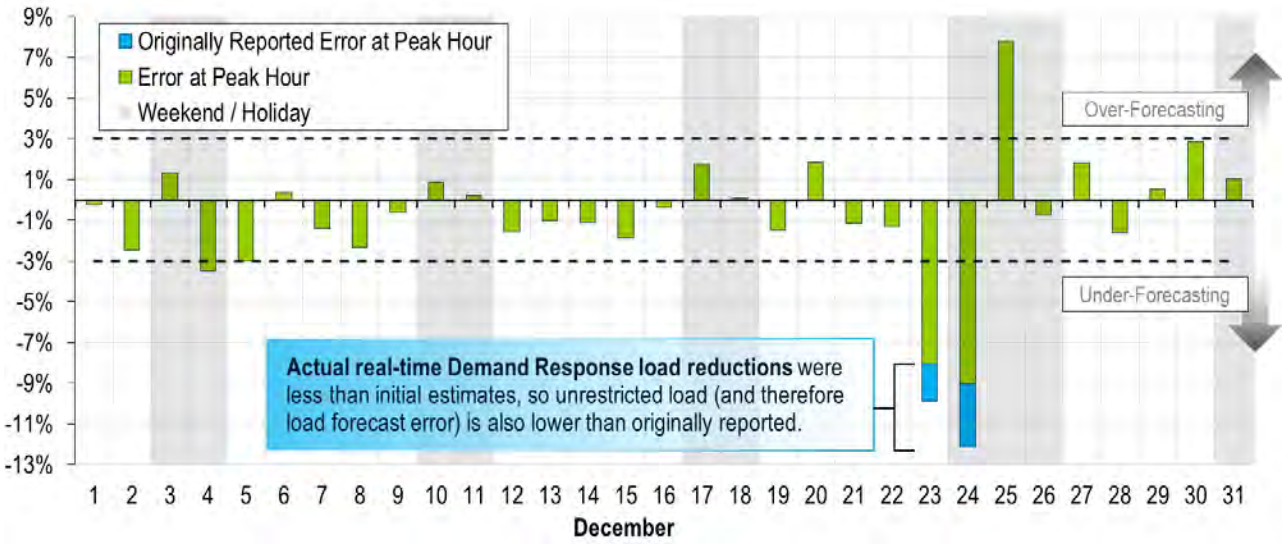


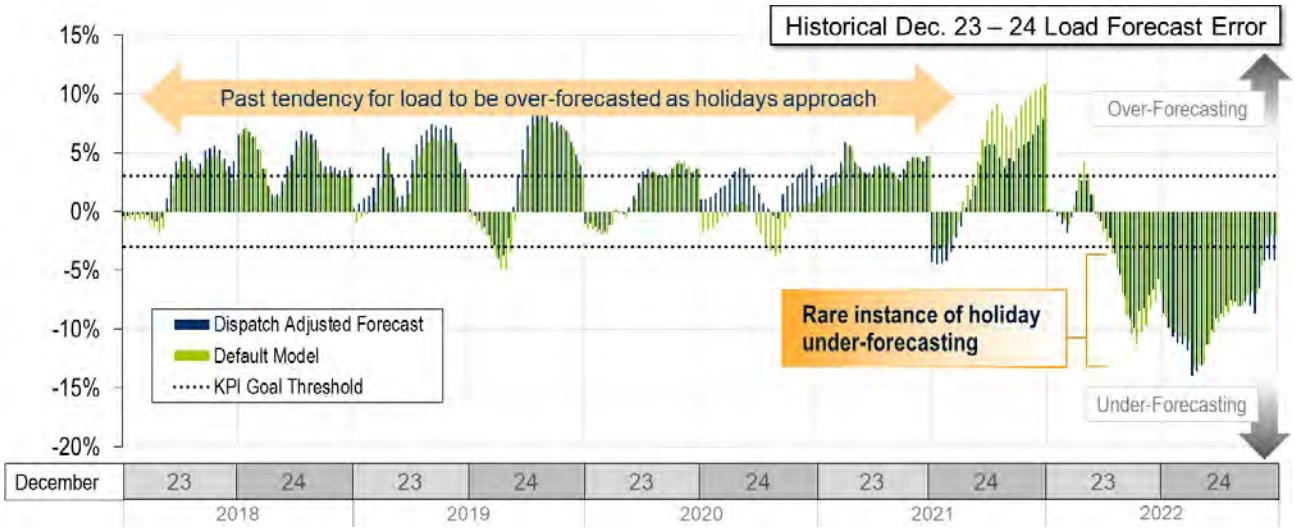
Figure 20 presents graphic presents the daily peak forecast error for December.

Figure 20. December Daily Peak Load Forecast Error



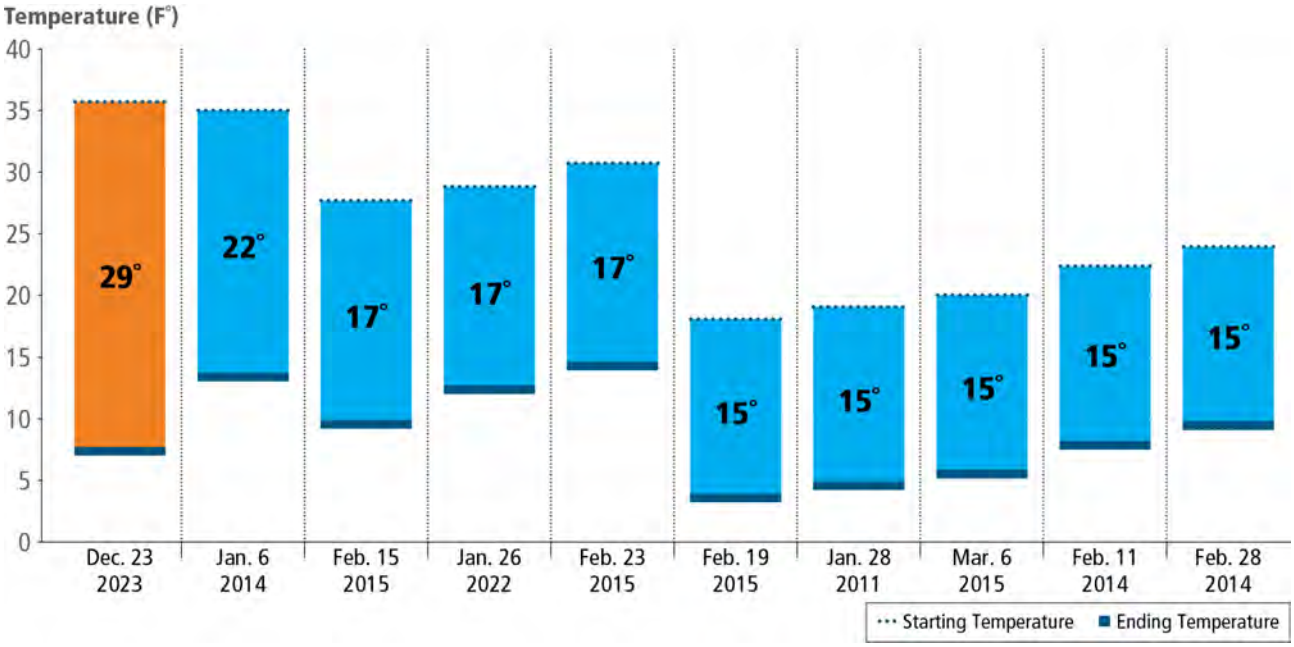
The extreme weather not only included bitter cold temperatures that were outside of the data sample used to train the load forecast models (mid-2019 to mid-2022), but also a rapid temperature drop, strong winds, heavy icing and snowfall, all of which occurred unusually early in this winter. Figure 21 presents the historical load forecast error the past five years.

Figure 21. Historical Dec. 23–24 Load Forecast Error



The load forecast is determined by an algorithm that considers expected weather conditions, day of the week and holidays. The model had not been exposed to the conditions that occurred on Dec. 23, with the confluence of unprecedented cold temperature drops, the holiday and the weekend. Within the PJM footprint, the difference between the high and low temperatures on Dec. 23 was one of the greatest in recorded history, as shown in the Figure 22.

Figure 22. Dec. 23 High and Low Temperatures



In Figure 22, the top and bottom of each bar represent the starting and ending temperature for each day, respectively.

The following primary drivers contributed to the load forecast error observed on Dec. 23 and 24:

- Extreme weather – severe cold and blizzard conditions, the most drastic temperature drop in at least 10 years, and early occurrence of cold weather
- Holiday impacts, which usually result in lower demand levels than normal

While PJM uses a sophisticated set of load forecasting tools and processes, we believe the Dec. 23 and 24 load forecasts highlight a case where two simultaneous conditions, a holiday and extreme weather with very limited analogous history, occurred together to produce atypically large forecast errors. PJM is already engaged with an independent party to further investigate enhancements to the load forecasting process, in general, and related to these specific events.

Emergency Generation and Demand Response Performance

Altogether, a Maximum Generation Action, Demand Response and public Call for Conservation helped address challenging operating conditions on Dec. 23 and 24. This section discusses information regarding the use of emergency resources. Information regarding the Call for Conservation is presented in the Government, Member & Media Outreach section.

PJM issued a Max Generation Action on Dec. 23 between 17:30 and 22:00 and observed a total increase of approximately 2,300 MW as a result of generation resources operating between their economic maximum and emergency maximum limits. Similarly on Dec. 24, PJM issued a Max Generation Action between 04:30 and 22:00 and observed a total increase of approximately 2,800 MW as a result of generation resources operating between their economic maximum and emergency maximum limits.

Demand Response was used to reduce peak loads in the entire PJM region during the winter storm. PJM called on Demand Response two times to address operational challenges with capacity shortages.

As described previously, PJM called for Demand Response on Dec. 23, which was to be implemented by 18:00. Demand Response with a capacity commitment is referred to as Load Management, which is comprised of Pre-Emergency and Emergency Demand Response. Load Management is required to reduce or maintain load at or below the committed value based on PJM dispatch within 30 minutes (quick lead time), 60 minutes (short lead time), or 120 minutes (long lead time). Based on the expected peak for the day, PJM dispatched both the 30-minute and the 60-minute lead resources on the evening of Dec. 23.

In total, PJM dispatched what it anticipated to be 4,336 MW of Load Management on Dec. 23 with 4,007 MW of 30-minute lead resources by 18:00 and another 329 MW of 60-minute lead resources by 18:30. In real-time, Curtailment Service Providers (CSPs) are required to provide estimates of their load reduction capability to PJM since customer load may already be low for other reasons (public appeal to reduce load, normal operating conditions, etc.). These estimates are intended to give PJM operators a quantity of load that will reduce if they deploy a specific category of Load Management. CSPs estimated, and therefore PJM expected, that 4,336 MW of load would be reduced based on the deployment on Dec. 23. PJM estimates, based on after-the-fact customer load data, that actual load reductions were approximately 1,100 MW. In total on Dec. 23, approximately 74% of the Demand Response that PJM operators dispatched and expected to reduce load did not.

As PJM was approaching the morning peak on Dec. 24, given the critical capacity condition, PJM system operators dispatched all Load Management with a total capacity commitment of 7,522 MW at 04:20.

4,007 MW of 30-minute Demand Response was expected to respond at 06:00.	329 MW of 60-minute Demand Response was expected to respond by 06:00.	3,186 MW of 120-minute Demand Response was expected to respond by 06:20.

CSPs estimated, and therefore PJM expected, that approximately 7,400 MW of load would be reduced. Based on after-the-fact customer load data, PJM estimates that actual load reductions from PJM dispatch was approximately 2,400 MW. This corresponds to approximately 68% of the Demand Response PJM operators dispatched and expected to reduce load not performing.

The significant difference between the data provided to PJM about load curtailment capability and the actual performance clearly identify an opportunity and need to improve the rules and processes regarding Load Management capability estimates.

Real-Time Interchange

Interchange transactions take the form of an import, meaning market participants purchase power from a neighboring area and sell into PJM, an export, where power is purchased from PJM and sold to an external area, or a wheel, where power is simultaneously purchased from a neighboring area, scheduled across PJM, and then sold to an external area. PJM is typically a net exporter of energy to neighboring systems, and that remained true in the days preceding Winter Storm Elliott. With this information in mind, PJM operators took a conservative stance in preparing for the Dec. 23 and Dec. 24 operating day and planned for sufficient reserves to meet both forecast internal load and the needs of neighboring systems who rely on support from PJM in the form of interchange transactions and emergency purchases.

As PJM made the decision to issue Cold Weather Advisories and Alerts for these operating days, the bitter cold temperatures traveled across the country from the north and west to the south and east. Early in the day on Dec. 23,

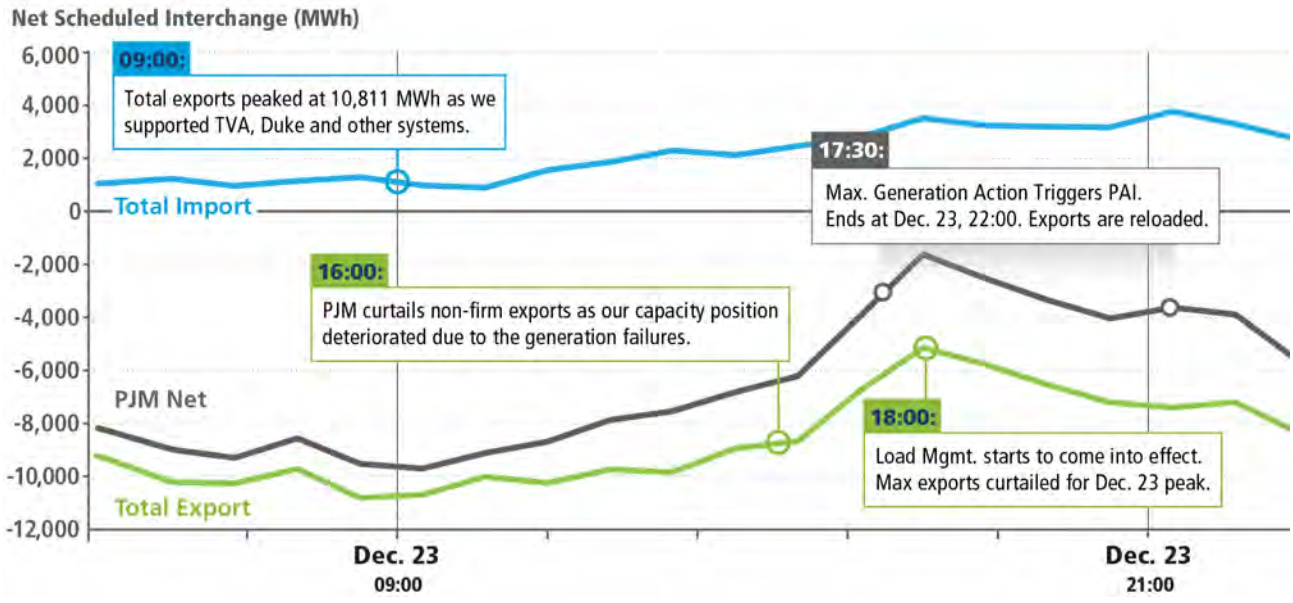
areas to PJM's west and south were already experiencing bitter cold temperatures. PJM was exporting energy throughout the morning and early afternoon on that day. Throughout the Dec. 23 to 24 period, PJM was balancing the extremely tight capacity situation due to the unprecedented amount of generator trippings and forced outages, controlling flows on the AEP-Dominion IROL[5] interface, as well as the extreme system conditions faced by our neighbors to the south.

Dec. 23

At the start of Dec. 23, PJM exported over 8,000 MWh for the hour ending 01:00 and increased that amount over the morning hours to reach almost 11,000 MWh for the hour ending 10:00 (Figure 23). These exports included the supply of emergency energy to TVA during the hours ending 07:00 through 11:00. During hour-ending 13:00, exports started a slight downward trend, and as PJM's capacity position continued to deteriorate, non-firm exports to adjacent areas were ultimately curtailed via a Maximum Generation Emergency Action. PJM system operators initiated the curtailment of non-firm export transactions at hour ending 17:00 by limiting roughly 400 MWh of exports, and quickly jumped to limiting well over 3,000 MWh of transactions each hour from hours ending 18:00 through 20:00. At that point, PJM system operators began a transition out from the heaviest Maximum Generation curtailments, with most transactions resuming full flow by hour-ending 22:00. In anticipation of, and in response to the Minimum Generation Action on Dec. 23, PJM curtailed in total almost 14,000 MWh of exports.

Figure 23 presents the Net Scheduled Interchange on Dec. 23.

Figure 23. Dec. 23 Net Scheduled Interchange



Dec. 24

When current and forecast system conditions indicated reduced availability to support exports on Dec. 24, the Transmission Load Relief (TLR) mechanism was considered as an option to provide relief for the AEP-Dominion IROL interface; however, the resulting analysis showed the need for an excessive volume of tag[6] curtailments on neighboring

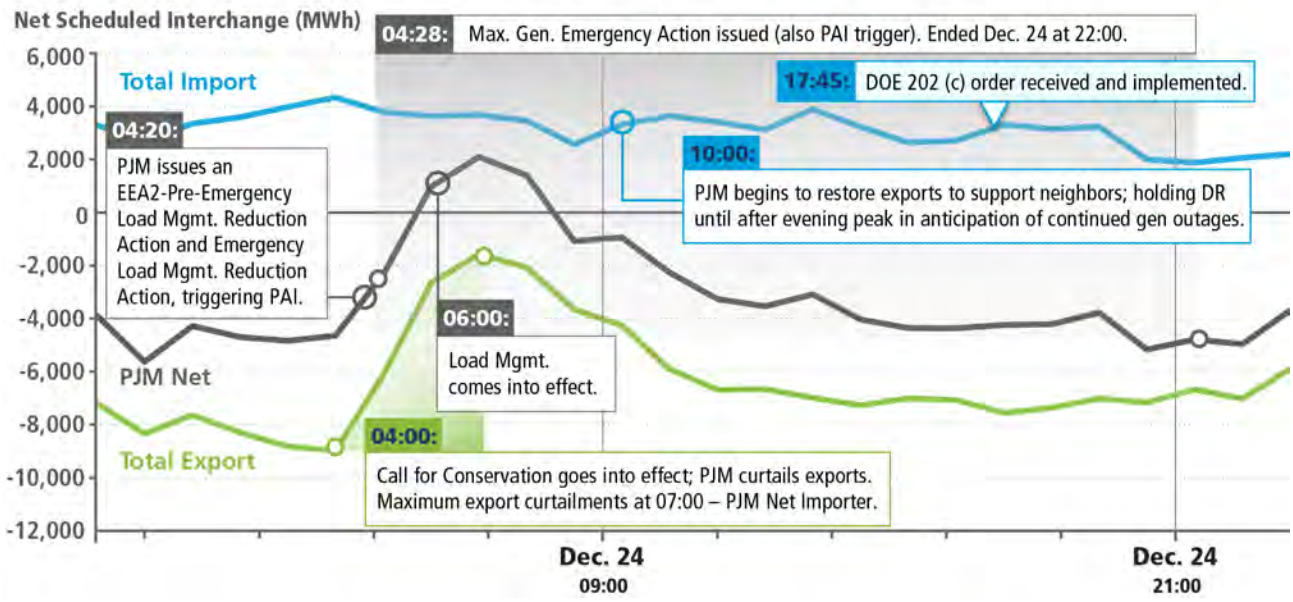
[5] Interconnection Reliability Operating Limit (IROL) is a system operating limit that, if exceeded, could lead to system instability, uncontrolled separation, or cascading that adversely impact the reliability of the bulk electric system.
[6] A tag is information describing a physical Interchange Transaction or Intra-BA Transaction and its participant.

systems that were already experiencing significant issues of their own. PJM system operators concluded that issuing a TLR would create far-reaching impacts across the Eastern Interconnection and likely make system conditions and emergencies worse for our neighbors. PJM also elected to limit curtailment of exports over the midnight period knowing the severe system conditions of our neighbors to the south. This limited PJM's ability to pump hydro stations.

Facing both a capacity emergency and lack of controlling options for AEP-DOM, PJM made the decision to take a more surgical approach and initiated curtailments in anticipation of a Maximum Generation Emergency Action, which was ultimately declared at 04:25. PJM system operators began limiting non-firm exports in hour ending 05:00 and increased the magnitude of curtailments by hour ending 06:00 when they had also begun limit firm exports. The most significant curtailments occurred in hour ending 08:00 with over 4,000 MWh of firm transactions limited and over 5,000 MWh of non-firm exports limited. Both PJM and its capacity deficient neighbors were experiencing peak loads at the same time, and PJM did not have excess capacity to support export requests regardless of the supporting transmission service priority. After the morning peak load, PJM slowly started to lift the limits on exports; however, the duration of this event was much longer than that seen on Dec. 23, with firm curtailments persisting until 12:00 and non-firm curtailments persisting until 15:00. For the event on Dec. 24, PJM curtailed over 45,000 MWh of export transactions. Conversely, PJM observed over 40,000 MWh of import transaction curtailments on Dec. 24, primarily resulting from TLRs issued by neighboring Reliability Coordinators (RCs). At the peak of the curtailments, PJM briefly transitioned to an overall net-importer of energy for several hours on the Dec. 24, with a net schedule of approximately 2,800 MWh into the footprint for hour ending 08:00.

Figure 24 presents the Net Scheduled Interchange on Dec. 24.

Figure 24. Dec. 24 Net Scheduled Interchange

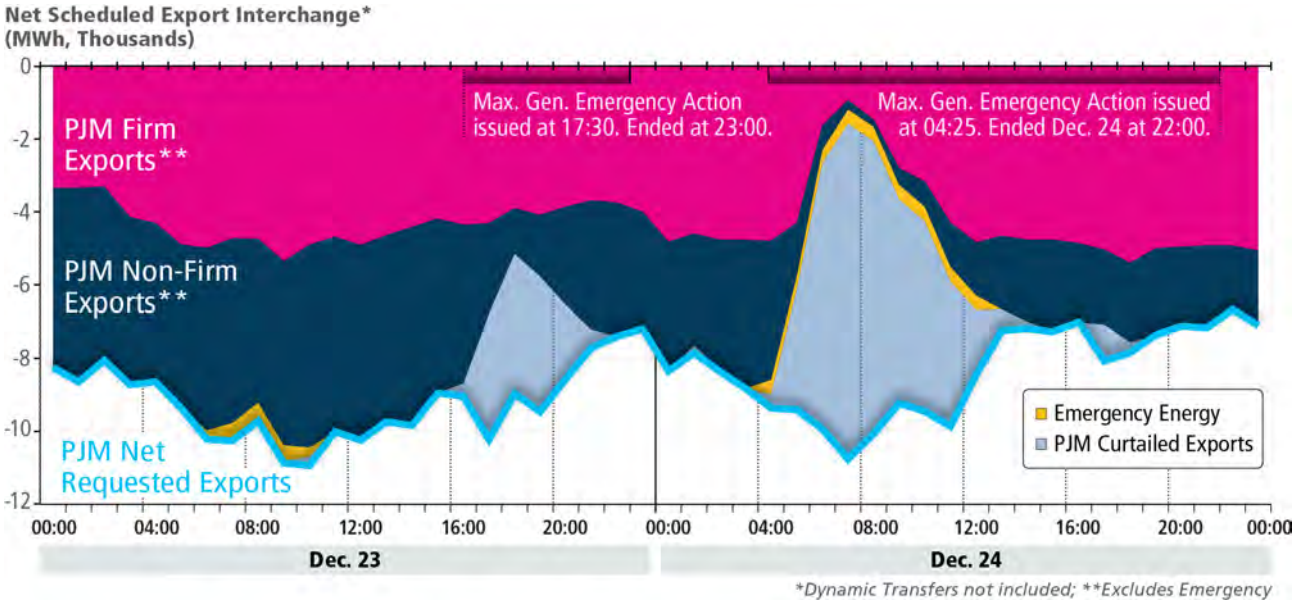


Coordination With Neighbors

As the extreme cold temperatures moved through areas to the southwest of the PJM footprint, neighboring systems began to experience strains. On both Dec. 23 and Dec. 24, PJM coordinated closely with its neighbors to maximize transfers. PJM provided emergency energy to adjacent systems as system conditions allowed on both Dec. 23 and Dec. 24 (Figure 25) before eventually having to reduce exports in order to serve consumers within the PJM footprint.

Transmission constraints also limited PJM's ability to support export transactions across the southern interfaces. These constraints included the pre-contingency emergency thermal limit of the Broadford 765/138 kV transformer and post-contingency transfer limit of the AEP-Dominion IROL interface. Figure 25 presents the Net Scheduled Exports for Dec. 23 through Dec. 24.

Figure 25. Dec. 23 and Dec. 24 Net Scheduled Exports



Comparing the values in Figure 25 to the supply/demand conditions that PJM actually experienced confirms that PJM could not have met system demand only by cutting non-firm exports. On Dec. 23, 2022, at 17:30, PJM issued a Pre-Emergency Load Management Reduction Action for the 30-minute and 60-minute Demand Resources that resulted in load reductions of about 1,100 MW. At the same time, PJM system operators also issued a Maximum Generation Emergency Action that resulted in an average of 2,372 MW of additional generation. In total, these actions had about 3,472 MW of impact. In comparison, non-firm exports were 1,241 MW for hour 18:00 and were 1,683 MWs for hour 19:00. Accordingly, even if the operators had cut all non-firm exports, there would have been a deficit of at least 1,789 MW needed to satisfy PJM load and firm exports. Pre-Emergency and Emergency Actions thus would have been necessary to satisfy capacity needs even if all non-firm exports had been cut.

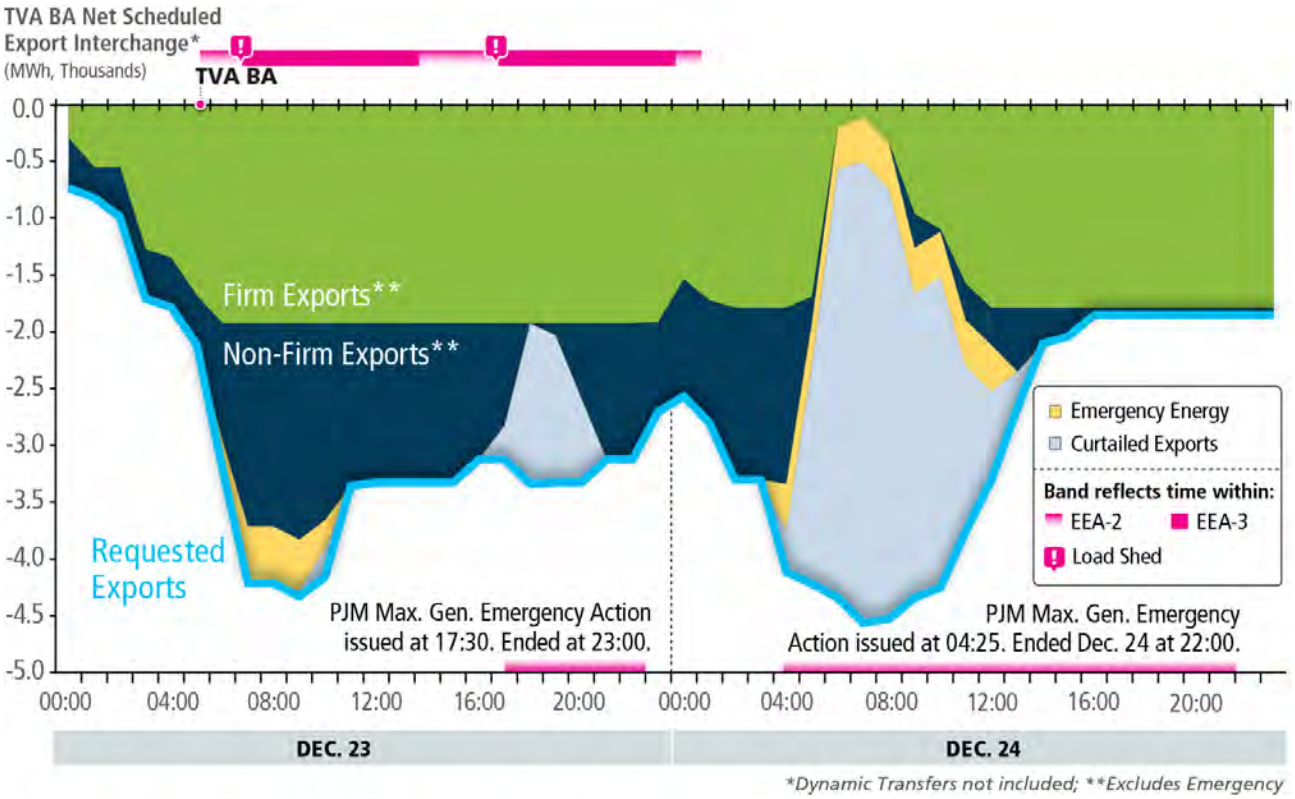
The situation for Dec. 24 is similar. At 04:20, PJM issued a Pre-Emergency Load Management Reduction Action and an Emergency Load Management Reduction Action that covered all Demand Resources and resulted in about 2,400 MW of load reduction. And at 04:28, PJM issued a Maximum Generation Emergency Action that it resulted in an average of about 2,879 MW in additional generation. In total, these actions had 5,279 MW of impact. In comparison, for hour 05:00, non-firm exports were 1,820 MW, falling to a low of 591 MW in hour 8:00 and increasing to a maximum level of 2,359 MW in hour 19:00 before the PAIs ended at 22:00. Accordingly, even if the PJM system operators had cut all non-firm exports there would have been a deficit between about 4,688 MW and 2,920 MW during this period needed to satisfy PJM load and firm exports. Pre-Emergency and Emergency Actions thus would have been necessary even if all non-firm exports had been cut.

Figure 25 also shows that PJM prioritized meeting its own load by cutting exports – both firm and non-firm – when necessary. The graph shows a significant number of hours in which the assistance requested by other regions was not

supplied. This correlates to the periods when PJM needed most of its generation for internal loads notwithstanding that, during some of these times, other regions were seeking emergency supplies.

As presented in Figure 26, PJM was able to assist TVA by providing non-firm exports during times that the TVA system was shedding load, which is represented by the fuchsia bars indicating when TVA was in an EEA-2 or EEA-3. Had PJM not done so, it is likely that TVA would have been required to engage in additional load shedding beyond what actually occurred.

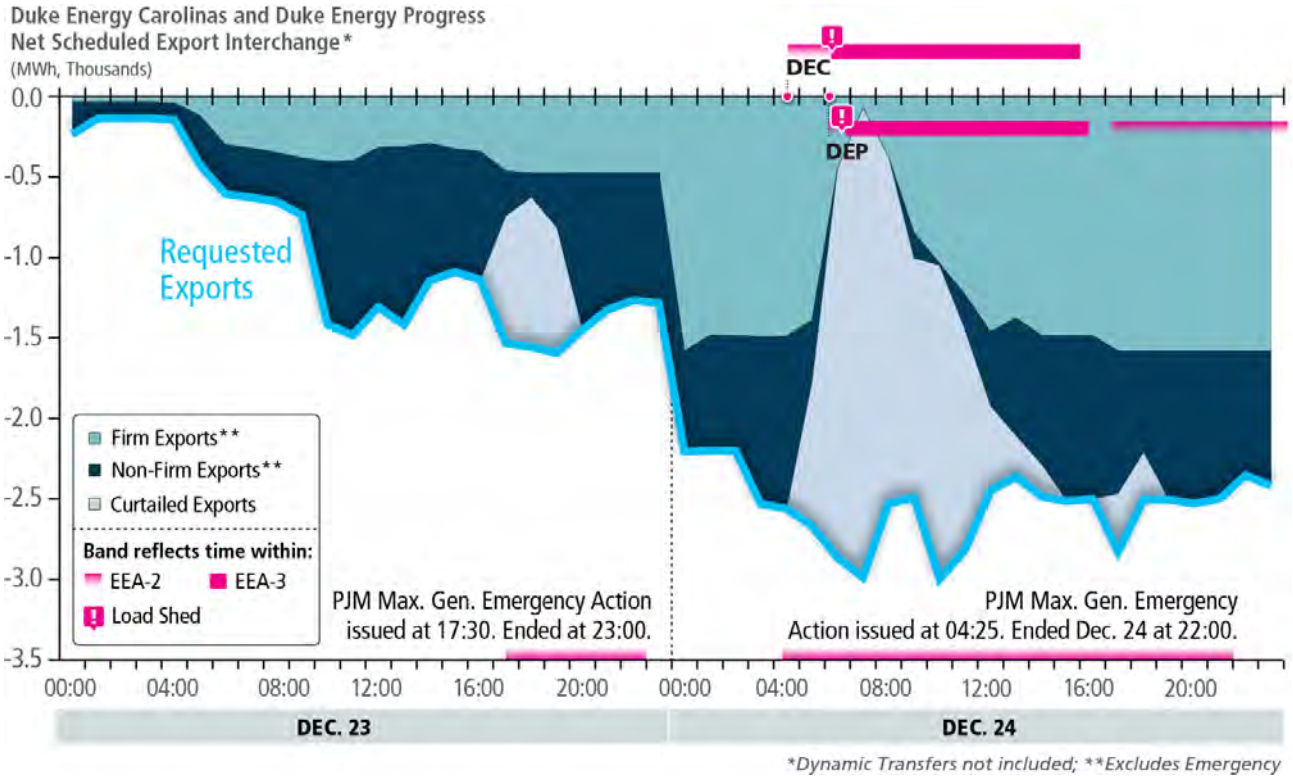
Figure 26. TVA BA Net Scheduled Export Exchange



The non-firm exports supplied to TVA provided assistance during periods when TVA was in a capacity deficient condition.

Similarly, the non-firm exports supplied to Duke Carolinas and Duke Energy Progress provided assistance to those systems when they were experiencing capacity deficient conditions as shown in the Figure 27.

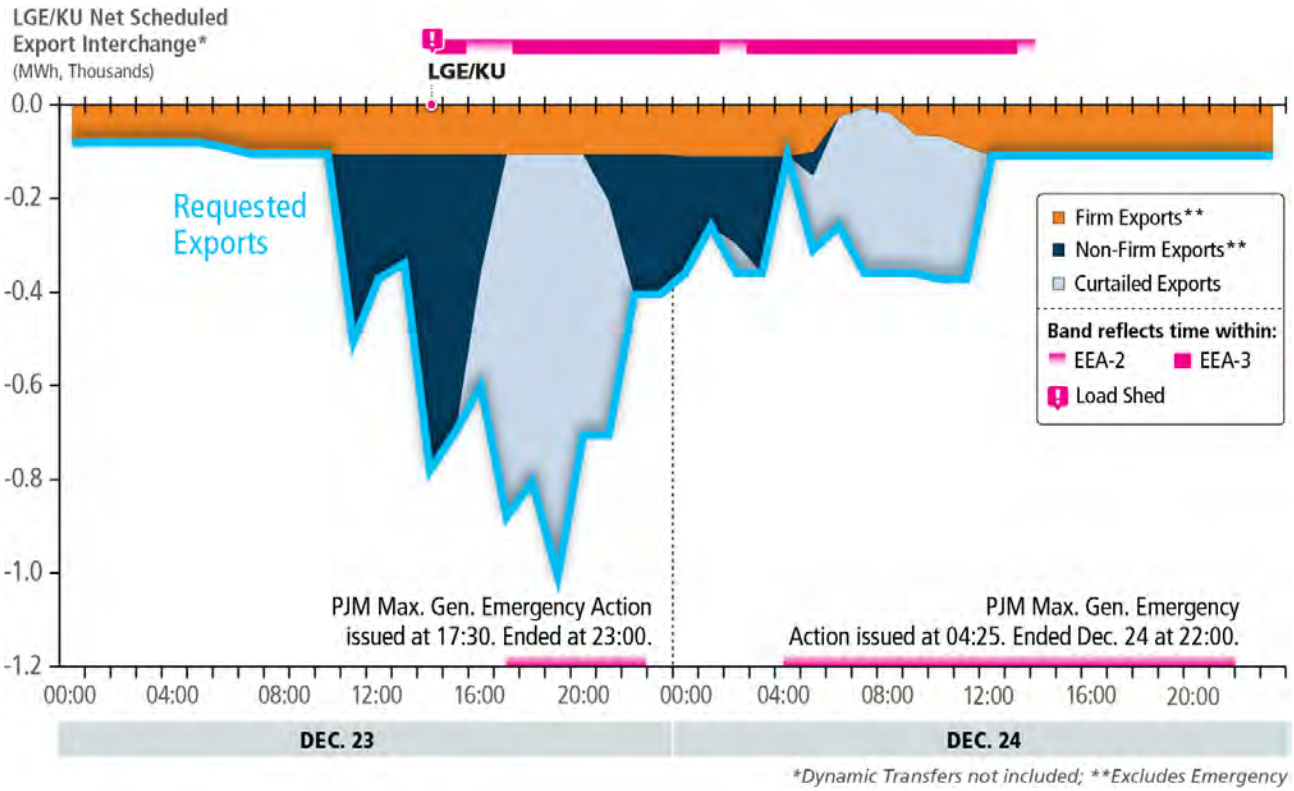
Figure 27. Duke Energy Carolinas & Duke Energy Progress Net Scheduled Export Interchange



As presented in Figure 27, PJM was also able to provide assistance by supplying non-firm exports to Duke Carolinas and Duke Energy Progress when they were shedding load. Again, if PJM had not provided this assistance, it is likely that Duke Carolinas and Duke Energy Progress would also have had to engage in more load shedding.

Lastly, Louisville Gas and Electric Company and Kentucky Utilities Company (LGE/KU) also received non-firm exports when they were experiencing capacity deficit conditions as shown in Figure 28.

Figure 28. LGE/KU Net Scheduled Export Interchange



PJM made non-firm deliveries to LGE/KU when the region was shedding load. Had PJM not made these exports, additional load shedding would likely have been needed.

Generation Performance

Prior to the operating day and Winter Storm Elliott, PJM had issued both Cold Weather Advisories and Cold Weather Alerts. Both procedures notify Generation Owners, Transmission Owners, and all PJM members of impending cold temperatures and to take action. Specifically, Generation Owners must take freeze protection actions, notify PJM of any operational changes or limitations as a result of the imminent cold weather, and update the operational parameters of generation units in Markets Gateway. These unit parameters include the Start-up and Notification Time, Min Run Time, Max Run Time, Eco Min, Eco Max, etc. Having accurate information about these unit parameters, in particular any changes to the start-up and notification times, are critical to PJM's decision making with respect to when a unit is given a commitment to run (i.e., when it is scheduled by PJM). PJM Dispatchers and their tools rely heavily on offer data information submitted by resource owner/operators. Given that 92% of forced outages that occurred were reported to PJM either after they occurred or with less than 60-minutes notice, it suggests that this information was not maintained throughout the event.

PJM started the operating day of Dec. 23 with 12,000 MW of unplanned outages, 4,293 MW of planned outages and 1,692 MW of maintenance outages at the evening peak on Dec. 23. These outages were primarily due to various equipment problems at generation facilities. PJM was tracking the cold temperatures arriving as a result of Winter Storm

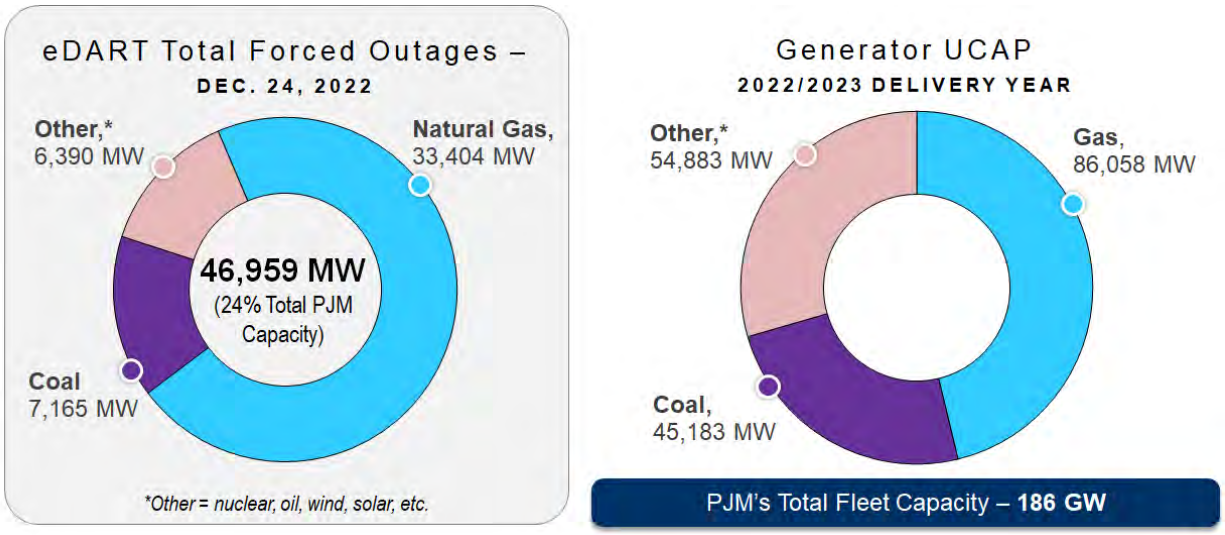
Elliott and did expect additional unplanned generation outages. For reference, the historic forced outage rate for winter is ~4.7%. The peak outage rate for the 2020/2021 winter period was 7.9%[7] and was 7.6%[8] for the 2021/2022 winter period.

While many generators performed well, the overall outage rate was unacceptably high. PJM had approximately 47,000 MW of units on forced outages during the hours when they were most needed. This correlates to a 24% forced outage rate. For comparison, the forced outage rate during the 2013 Polar Vortex was 22%. While a cross section of generation was impacted by the cold weather, gas plants and dual-fuel gas plants made up the majority of outages primarily due to mechanical issues likely resulting from the extreme cold.

Forced Outage Analysis

As presented in Figure 29, the majority of forced outage MW were from natural gas facilities. Approximately 70% of all outages were natural gas, about 16% coal, and the remainder were oil, nuclear, hydro, wind and solar.

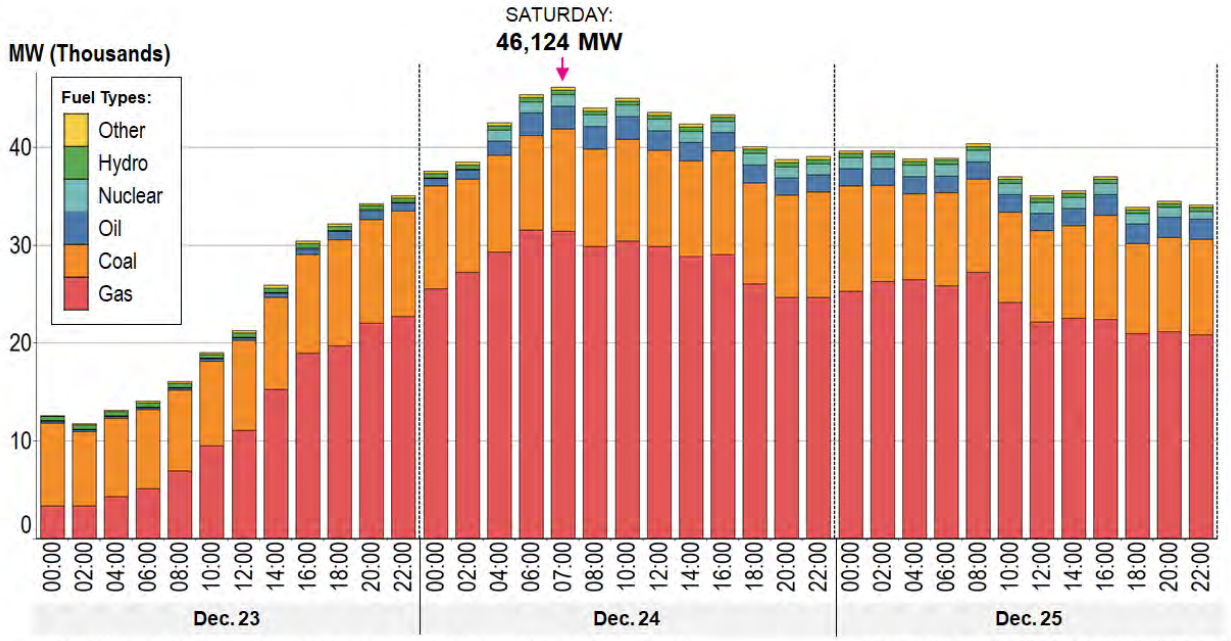
Figure 29. Forced Outages



As shown in the Figure 30, forced outages increased significantly and quickly throughout the day on Dec. 23 and peaked at over 46,000 MW at 07:00 on Dec. 24. Even as forced outage rates declined from the peak, they remained at an unacceptably high level through Dec. 25.

[7] Winter Operations of the PJM Grid: Dec. 1, 2020 – Feb. 28, 2021, PJM Operating Committee, April 8, 2021
[8] Winter Operations of the PJM Grid: Dec. 1, 2021 – Feb. 28, 2022, PJM Operating Committee, April 14, 2022

Figure 30. Dec. 23 and Dec. 24 Forced Outages

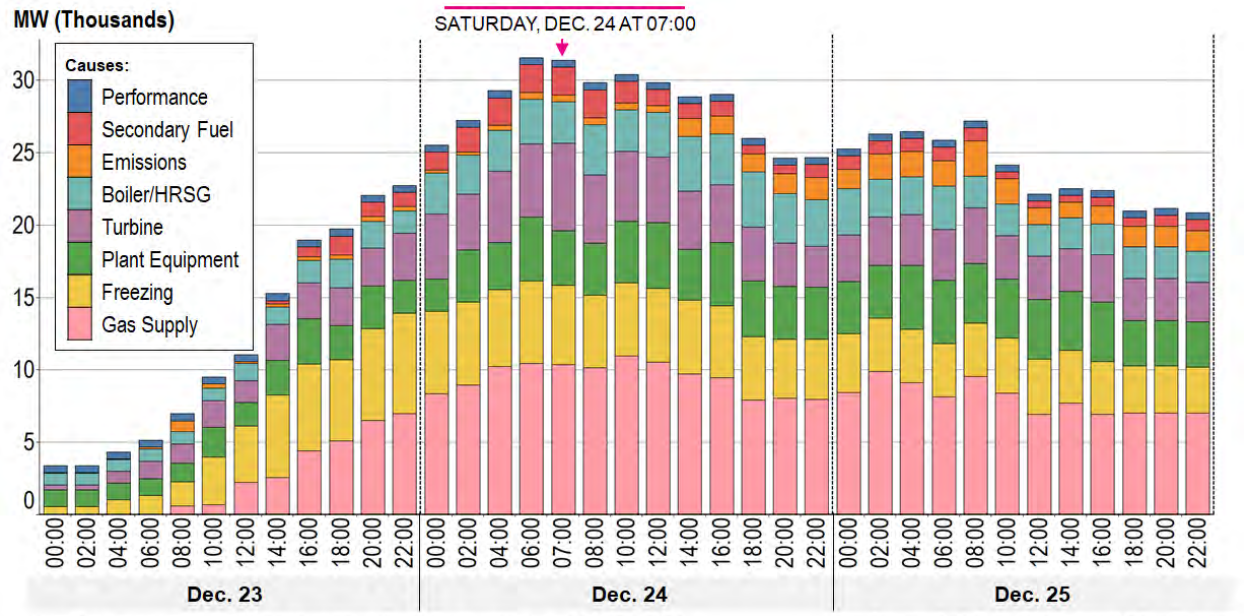


Note: Only even hours are shown for readability with the exception of Dec. 24, 2022, 07:00, which was the hour with the largest amount of forced outages and derates.

Source: GADS as of March 1, 2023. Wind and solar unit outages are not included in the data.

Looking more closely at the causes for the generation outages by fuel type indicates that various plant and mechanical failures, including freeze-related issues, were the major reasons units were unavailable. Figure 31 presents the gas unit forced outages. As with other resource types, outages on gas units were primarily attributed to physical plant issues (freezing and plant equipment issues), but gas generators also experienced a significant level of gas supply issues. The gas supply-related outages accounted for just over 11,000 MW (approximately 13% of total gas generation capacity) at the peak hour on Dec. 24. By contrast, during the 2014 Polar Vortex, the total gas resources that were unavailable on peak due to gas supply issues was 9,300 MW (approximately 19% of total gas generation capacity).

Figure 31. Dec. 23, 24 and 25 Gas – Forced Outages/Derates by Cause

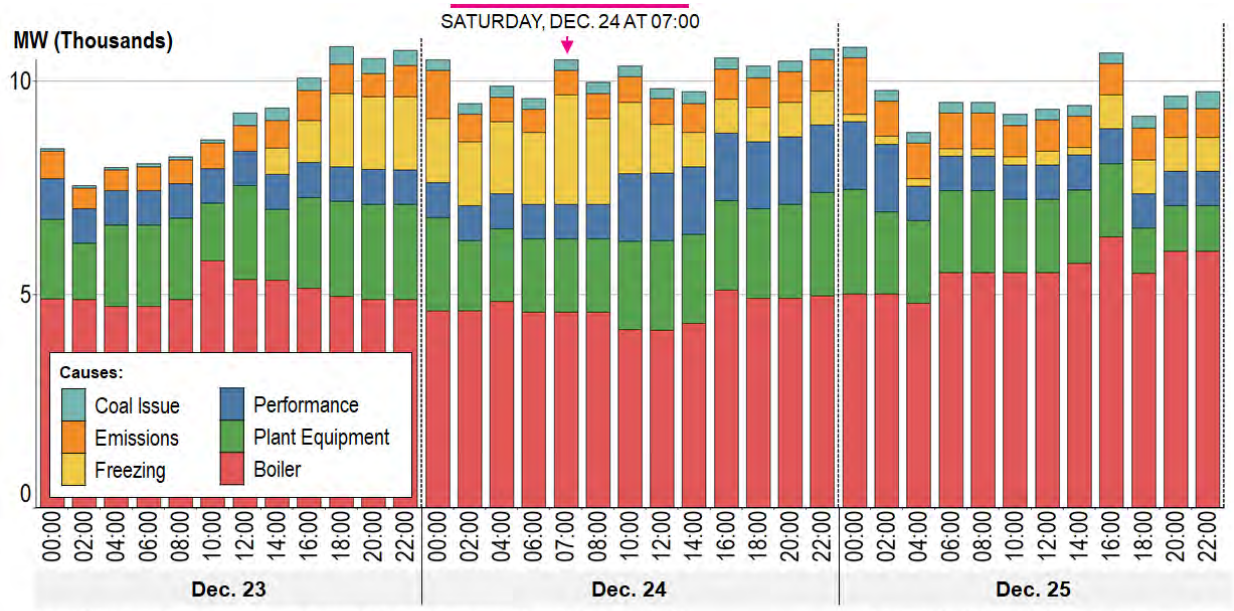


Note: Only even hours are shown for readability with the exception of Dec. 24, 2022, 07:00, which was the hour with the largest amount of forced outages and derates.

Source: GADS as of March 1, 2023. Wind and solar unit outages are not included in the data.

As presented in Figure 32, for coal units, boiler problems and tube leaks were the primary cause of outages and derates followed by other plant equipment issues. Freezing issues increased starting around 14:00 on Dec. 23 and peaked at approximately 07:00 on Dec. 24.

Figure 32. Dec. 23, 24 and 25 Coal Forced Outages/Derates by Cause

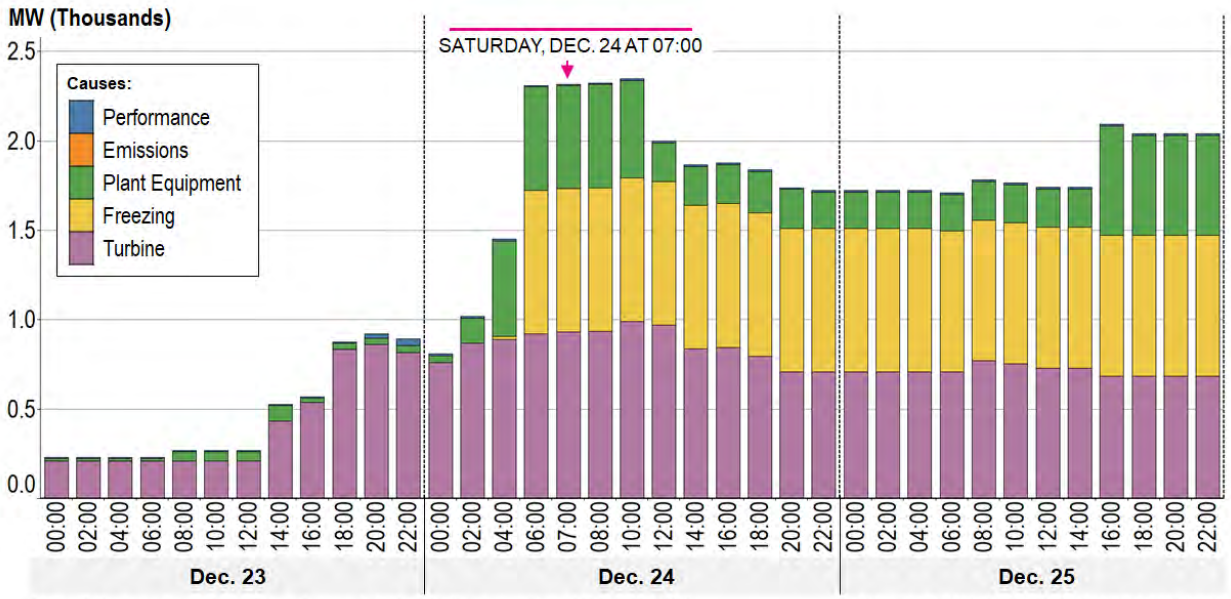


Note: Only even hours are shown for readability with the exception of Dec. 24, 2022, 07:00, which was the hour with the largest amount of forced outages and derates.

Source: GADS as of March 1, 2023. Wind and solar unit outages are not included in the data.

As shown in Figure 33, for oil units, turbine issues accounted for a large majority of the outages. A significant amount of freeze-related outages and derates were experienced from 06:00 on Dec. 24, and continued throughout the day on Dec. 25.

Figure 33. Dec. 23, 24 and 25 Oil Forced Outages/Derates by Cause

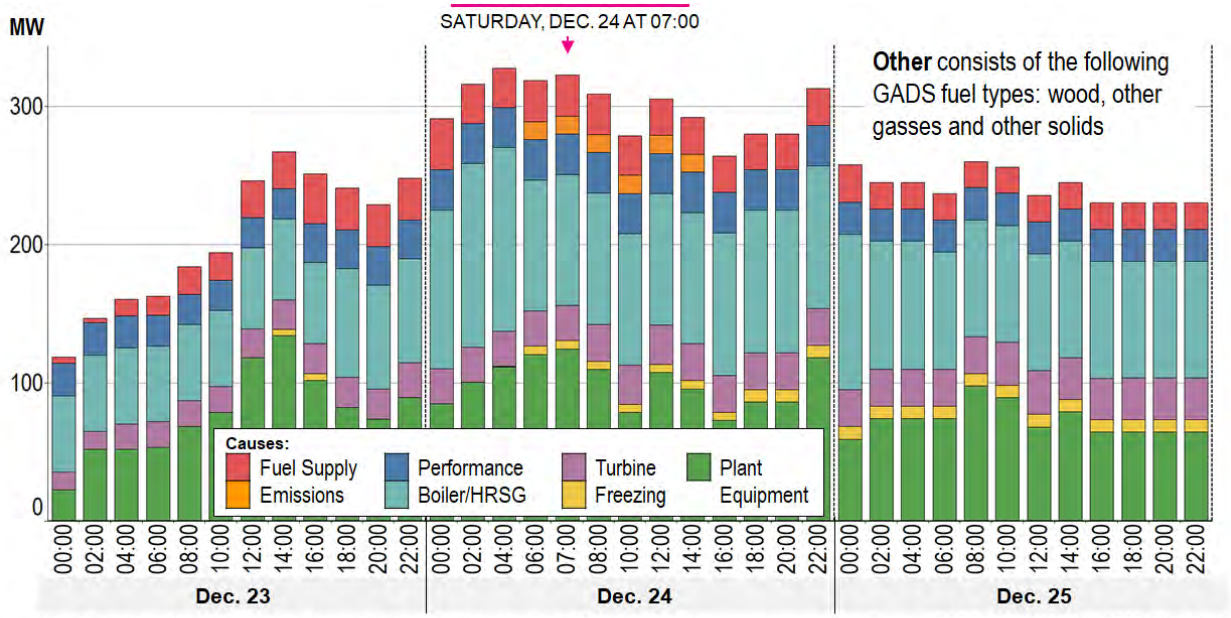


Note: Only even hours are shown for readability with the exception of Dec. 24, 2022, 07:00, which was the hour with the largest amount of forced outages and derates.

Source: GADS as of March 1, 2023. Wind and solar unit outages are not included in the data.

As presented in Figure 34, for generators fueled by wood, other gases or other solids, most outages/derates were attributed boiler, HRSG and other plant equipment problems.

Figure 34. Dec. 23, 24 and 25 Other – Forced Outages/Derates by Cause

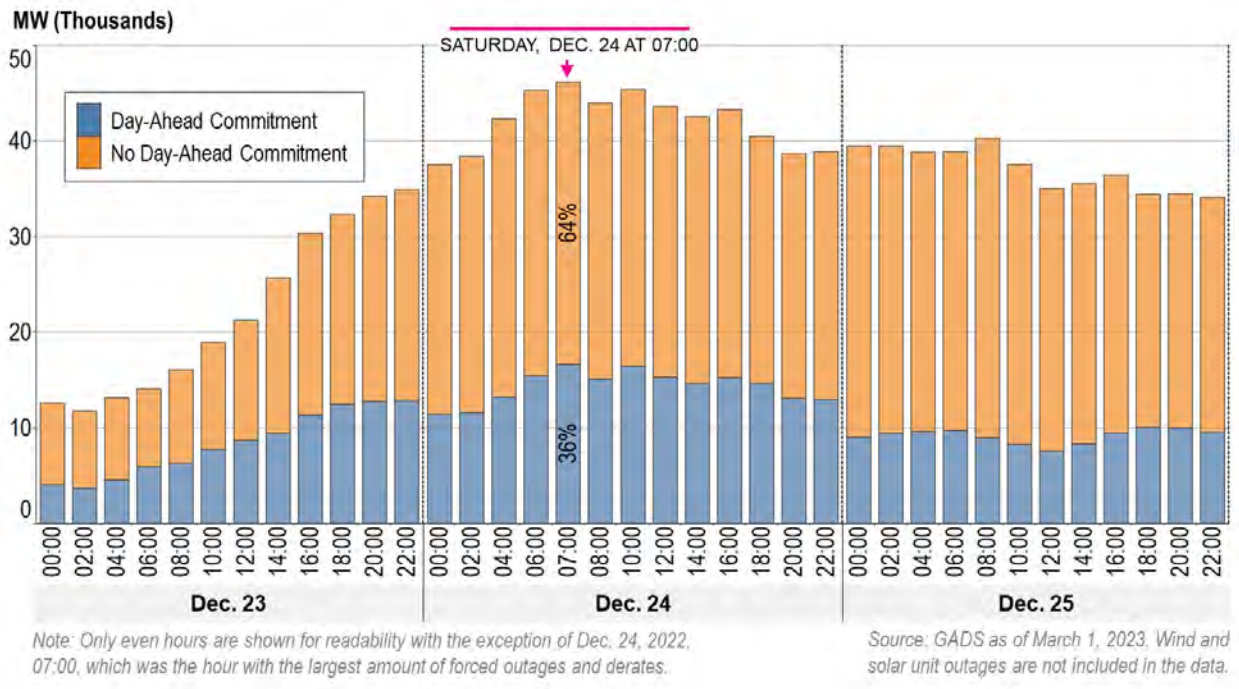


Note: Only even hours are shown for readability with the exception of Dec. 24, 2022, 07:00, which was the hour with the largest amount of forced outages and derates.

Source: GADS as of March 1, 2023. Wind and solar unit outages are not included in the data.

In addition to the causes of the forced outages and the outages by fuel type, Figure 35 presents the outages for units based on day-ahead commitments. This is an important piece of the puzzle to understand with respect to PJM's planning for the operating day. PJM always expects some resources will fail. On cold weather days in particular, this is considered and noted in PJM Manual 13. However, as Figure 35 shows, over 16,000 MW of generation that was committed in the Day-Ahead Market failed to perform.

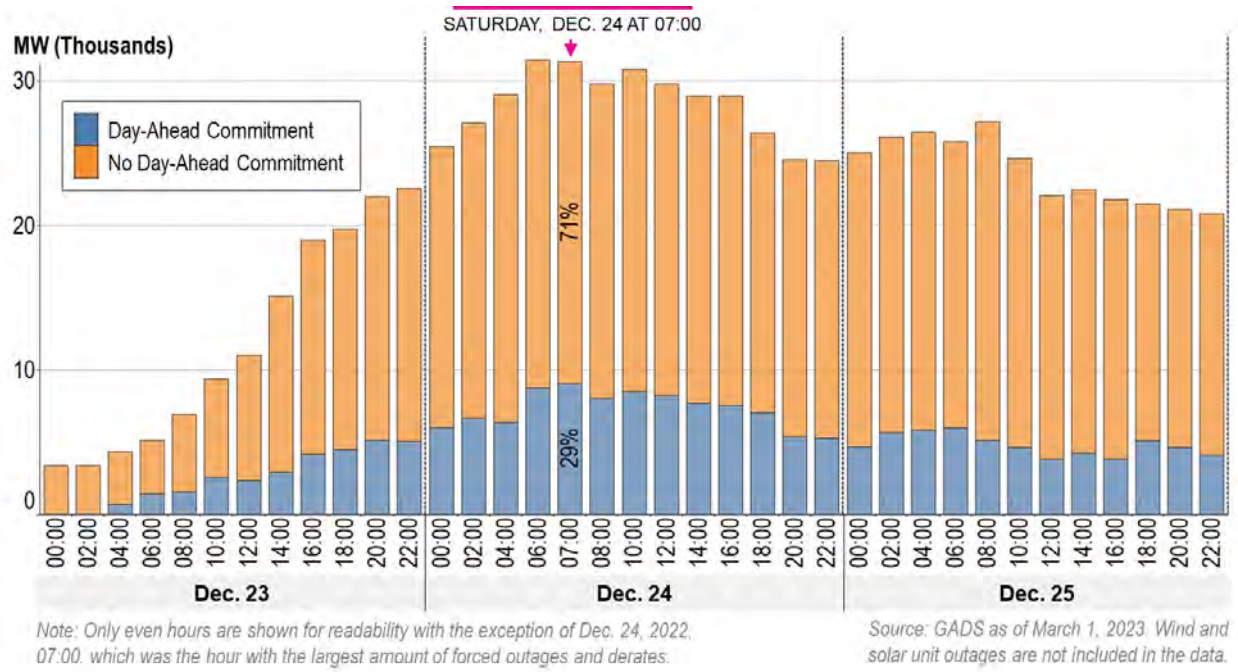
Figure 35. Dec. 23, 24 and 25 Forced Outages With and Without Day-Ahead Market Commitment



When scheduling replacement energy to account for the missing 16,000 MW, PJM was relying on the unit information submitted by Generation Owners to evaluate the amount of available reserves and the timelines needed to schedule those units if/when needed (15-minute notice, 30-minute notice, one-hour notice, etc.) As noted previously, PJM requires Generation Owners to update their parameters to reflect any changes from normal operating condition so that the reserve calculations are accurate. However, in the case of Winter Storm Elliott, these parameters were not updated for many generators. More specifically, the following information was not updated to align with actual operating conditions including longer notification times, extended minimum run times, inflexibility in dispatch range, etc. This was predominately related to gas-fired generators where pipeline restrictions, nomination deadlines and the unavailability of gas supply were not accurately reflected in generator operating parameters, despite having the ability to utilize Temporary Exceptions or Real-Time Values (PJM Manual 11, Sections 2.3.4.3 and 2.3.4.4) to convey this information accurately to PJM.

For the Dec. 23 operating day, only 6% (37 out of 578) of the gas-fired generators in the PJM system submitted increased notification time requirements. All others were reported as available to operate, with their normal operating parameters in place. This lack of timely and accurate information led to extremely challenging conditions for the PJM system operators that continued through the end of the day on Dec. 25. As presented in Figure 36, the failure of so many Day-Ahead Market committed units, coupled with the lack of generator parameter updates, led to a high volume of natural gas generators having no Day-Ahead Market commitment and then becoming forced outages due to lack of fuel.

Figure 36. Dec. 23, 24 and 25 Forced Outages With and Without Day-Ahead Market Commitment



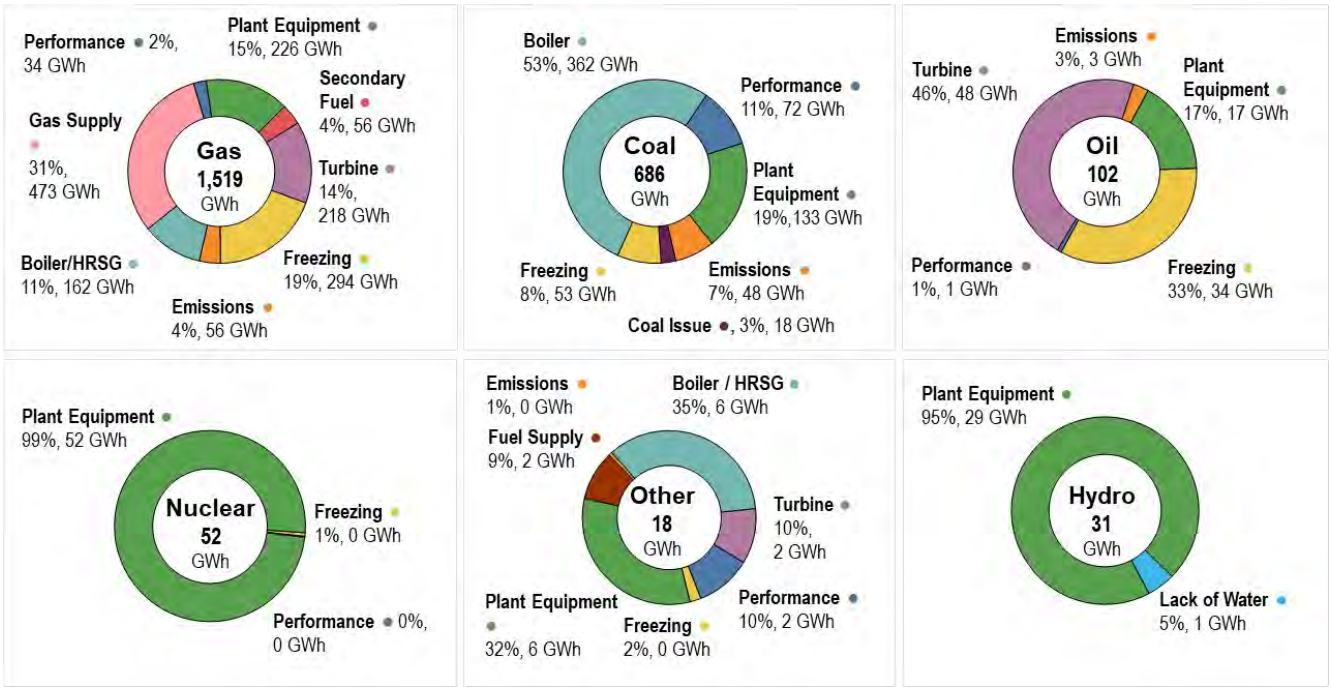
In addition to forced outages, approximately 6,000 MW of steam generation was called but was not online as expected per their time to start for the morning peak on Dec. 24. The vast majority of these resources were gas-fired resources.

The high rates of generator outages also limited PJM's ability to replenish pond levels for pumped storage hydro prior to the morning peak on Dec. 24. That left PJM with extremely limited run hours for pumped storage generation. Between forced outages, derates, generators that did not start on time, and the inability to fill pumped storage hydro ponds, PJM was operating with approximately 47,000 MW of generator unavailability for the Dec. 24 morning peak, including the unavailability of pumped storage resources to generate.

The highest forced outage rate during Winter Storm Elliott was over 24%, which is higher than PJM experienced during the Polar Vortex in 2014. This level of generation outages was unprecedented and not anticipated. PJM, along with the Independent Market Monitor, has undertaken efforts to determine what happened with these generators to understand both why these failures occurred and how to reduce them in the future. This is further discussed later in the report.

To effectively compare resource unavailability by fuel type and by cause during the Winter Storm Elliott event, both the reduction quantity and duration must be considered. While a 1,000 MW forced outage is much larger than a 100 MW forced outage, if the 1,000 MW forced outage only lasts one hour but the 100 MW forced outage lasts one day, then the 100 MW forced outage is a more significant unavailability event. Using MWh as the comparison metric incorporates both the magnitude and duration of the outage to give a more complete picture of the impact. Figure 37 presents the MWh analysis for a duration of Dec. 23 00:00 to Dec. 25 23:59.

Figure 37. Dec. 23, 24 and 25 Forced MWh by Fuel Type and Cause



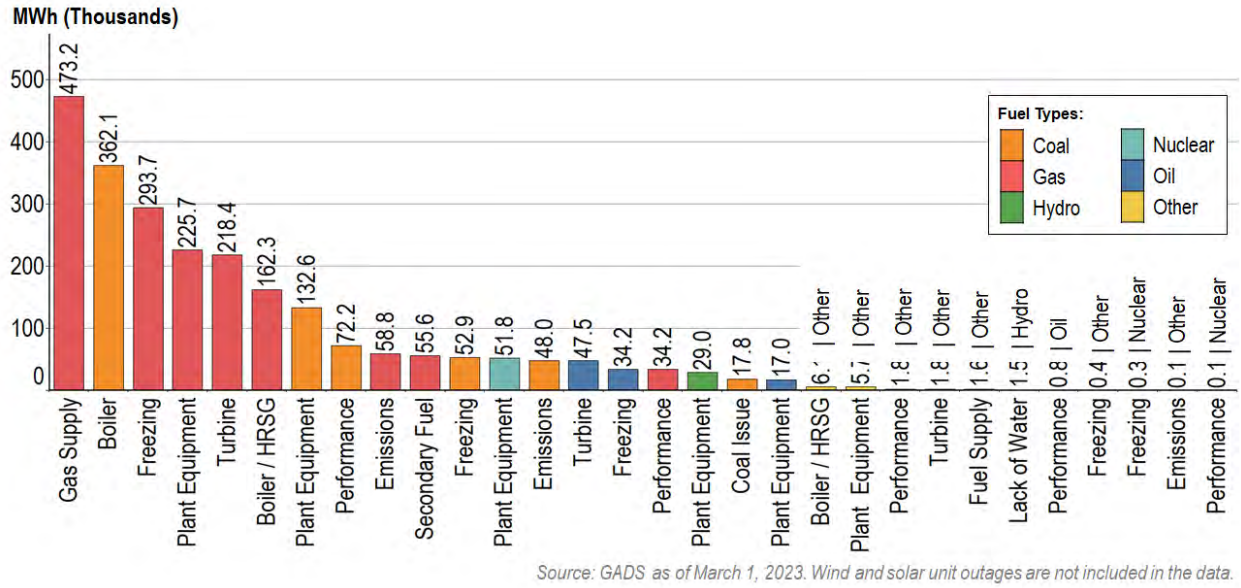
In Figure 38, total available MWh for the period of Dec. 23 to Dec. 25 was calculated by multiplying GADS Net Dependable Capacity by 72 hours. The MWh outage rates shown in Figure 38 were then overlaid to show availability by fuel type.

Figure 38. Dec. 23, 24 and 25 Availability by Fuel Type



Figure 39 breaks down the outage causes further, considering both fuel type and outage cause. Overall, freezing, plant equipment issues – including boiler, heat recovery steam generator (HRSG) and turbine problems, and emissions make up the majority of outages.

Figure 39. Dec 23, 24 and 25 Forced MWh by Fuel Type and Cause



Source: GADS as of March 1, 2023. Wind and solar unit outages are not included in the data.

Generation Cold Weather Operating Limit Analysis

As noted previously, PJM issued a data request in 2022 to capture the Cold Weather Operating Limit (CWOL) for each generating unit. This information indicates the minimum temperature that each unit can reliably operate to. The chart to the left in Figure 40 presents the results of an analysis of the percentage of units that reported in GADs specifically as freeze-related causes for their outages and tripped/failed to start at actual temperatures above or below their reported minimum operating temperature limit. The second chart (in Figure 40) shows a similar analysis, but it uses the effective temperature (i.e., wind chill) instead of the actual temperature. As can be seen, the effective temperature is a better indicator for identifying when generators are at risk of experiencing freeze-related issues. Based on the GADS data, 21,355 MW of generation incurred a forced outage at or above their limit and 18,544 MW experienced a forced outage below their limit.

PJM then expanded this temperature analysis look at specific temperature ranges. The purpose of this analysis was to understand the magnitude of deviations from the reported operating limits. This analysis drilled down to specific temperature ranges where a unit incurred a forced outage at/above or below their CWOL temperature. Note that there is one unit in the 0°F category, indicating that it incurred a forced outage exactly at its CWOL temperature. From the data analyzed, the majority (13,349 MW) of forced outages occurred within 10°F of units' CWOL temperature. Conversely, 17 units (3,113 MW) incurred a forced outage more than 20°F above their CWOL temperature, which may indicate that they either overestimated the capabilities of the unit or did not provide a practical or realistic CWOL temperature to PJM. There were 4,685 MW (five units) that were able to operate 20°F or more below their CWOL temperature.

Figure 40. Cold Weather Operating Limit Comparison Against GADS Reported Outage and Temperature

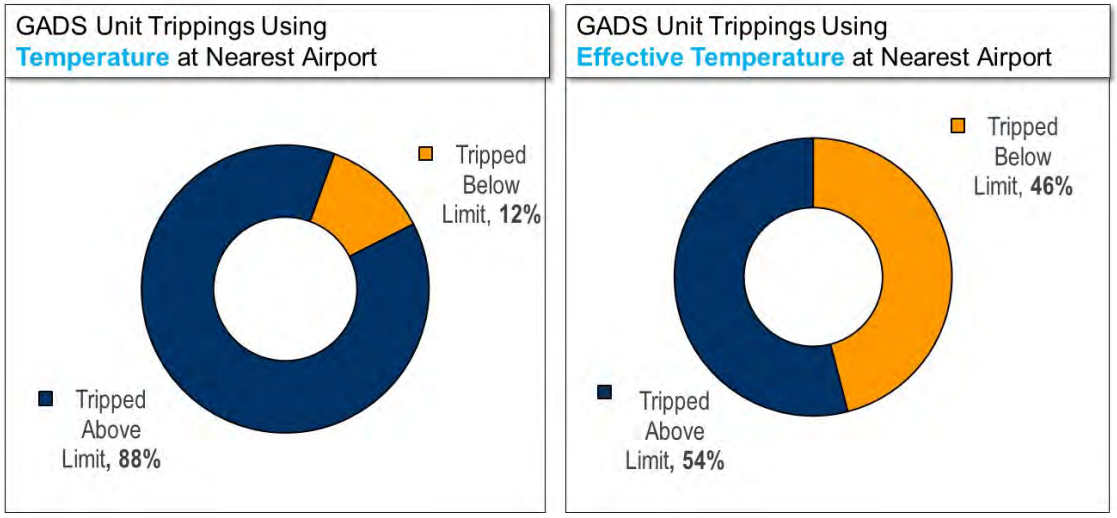
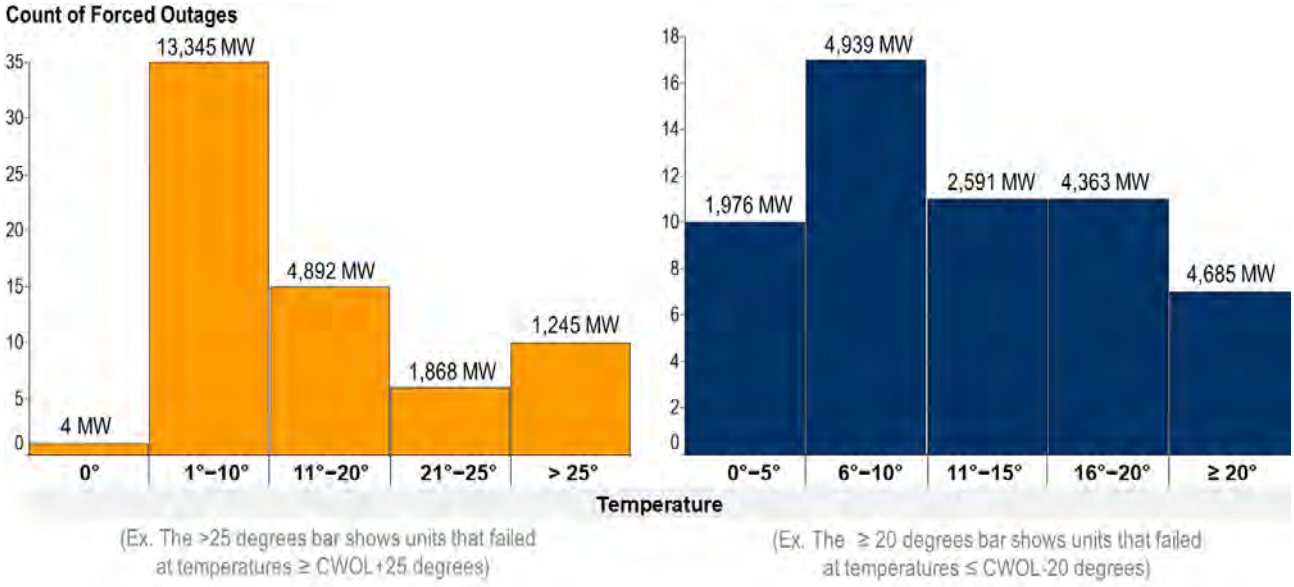


Figure 41 presents a comparison of the effective temperatures experienced by units at the time of a cold weather-related forced outage with their submitted CWOL temperature. The chart to the left presents the MW quantity of the units that failed at different temperatures ranges prior to reaching their CWOL temperature. The chart to the right (presented in blue) presents unit failures below their CWOL temperature.

Figure 41. Temperature Deviations for Weather-Related Forced Outages



Renewable Generation Performance

Figure 42 and Figure 43 represent the performance of both wind and solar resources. Both charts utilize a similar method to represent the maximum potential output, labeled Available ICAP, by taking the total Installed Capacity and subtracting out any generation outages (planned, maintenance and unplanned). The Available UCAP represents the expected performance based upon the capacity value of the Available ICAP. For the 2022/2023 Delivery Year, this value is 13% for wind and 38% for solar.

As shown in Figure 42, wind generation on average performed above its expected capacity. This is not unexpected and something PJM sees on the coldest winter days where the wind speed also increases customer demand due to increased heating needs. However, it should be noted that this does not hold true during the summer where the highest electric demand is coincident with the lack of any wind and its associated cooling effect on air conditioning usage.

Solar, on the other hand, only met or exceeded its capacity expectations during a few hours each afternoon, which was not coincident with the peak electric demand periods. That said, as noted above with wind, it is important to point out that lack of the heating from the sun does coincide with high heating demand in the winter, but the converse is true in the summer. During the peak summer hours, the electric demand is driven by heating from the sun, which is also when solar generation output is at its peak.

Figure 42. Wind Resource Performance

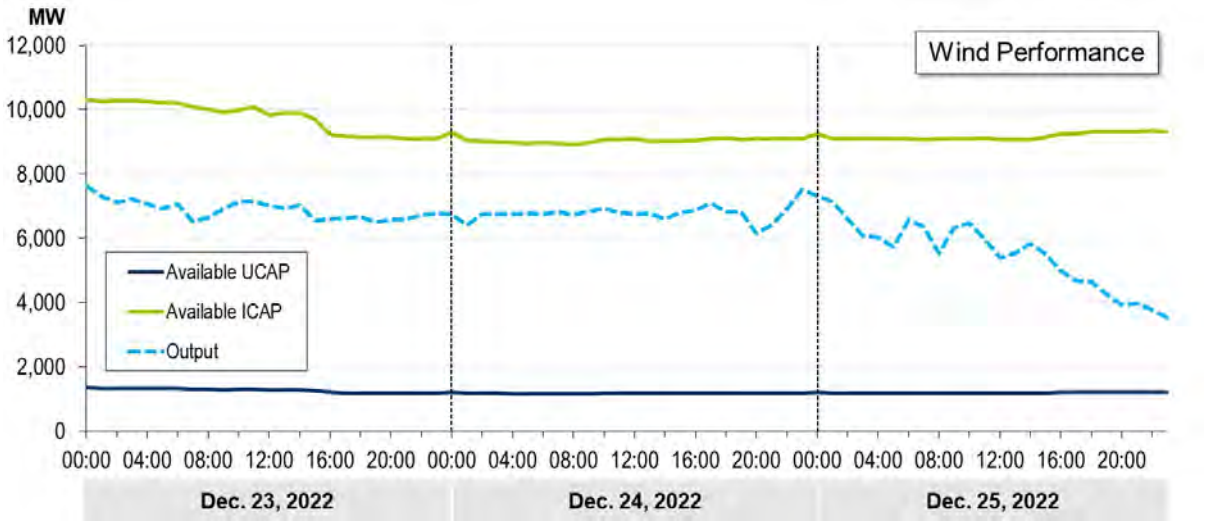
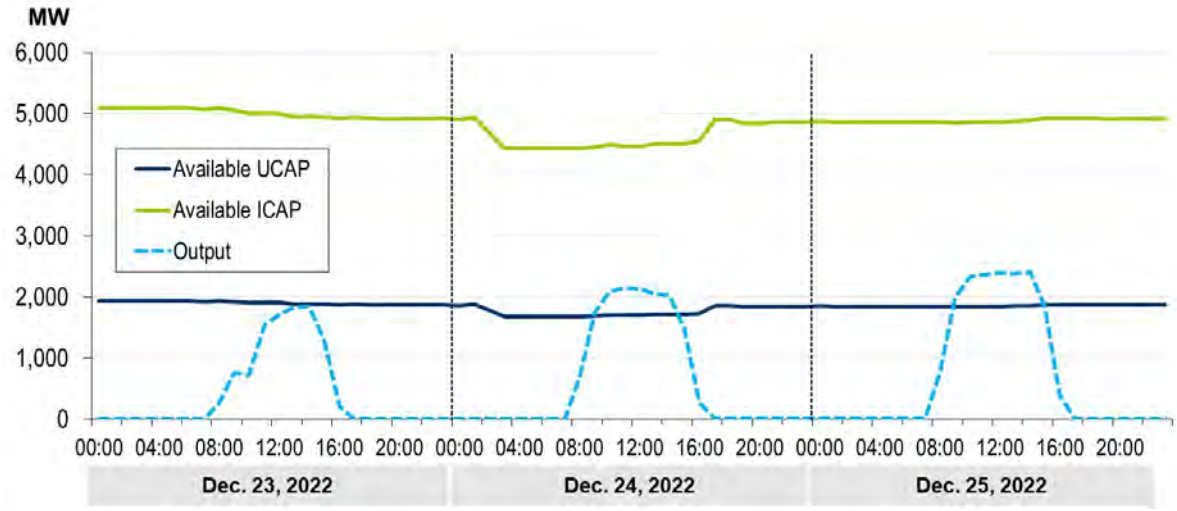


Figure 43. Solar Resource Performance

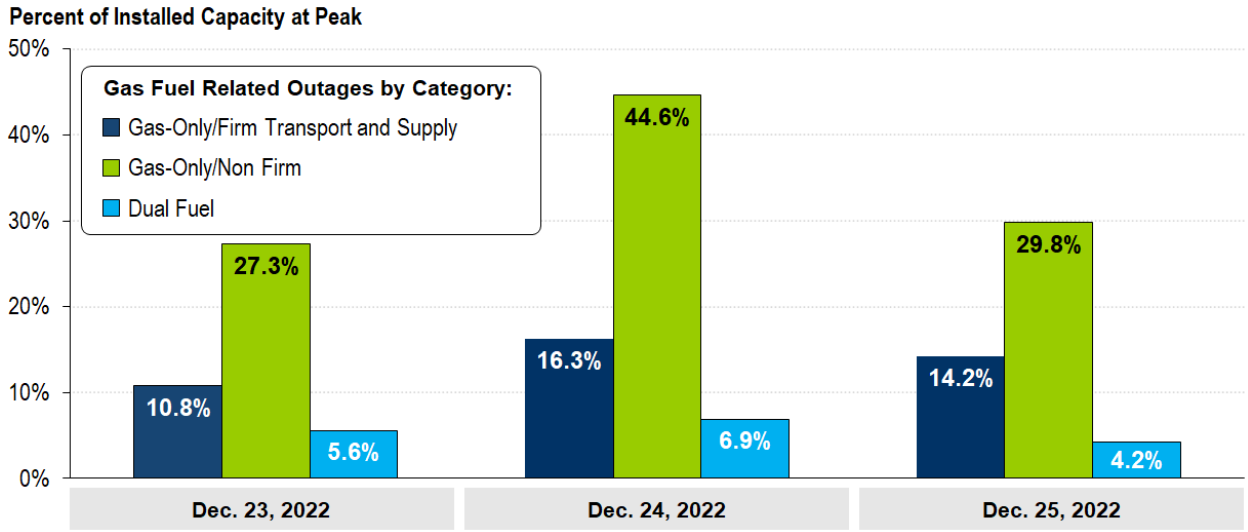


Fuel Security Observations

While PJM has focused on the 24% forced outage rate overall and by fuel type in this report thus far, it is also important to note that 76% of the generation fleet did perform well. In particular, hydro and nuclear had availability rates of 95%

and 98%, respectively, as shown in Figure 36. In addition, wind performance was well above the expected output, as shown in Figure 42. Furthermore, one of the more stark observations is the difference in the performance of gas units with respect to their level of fuel security. As shown in Figure 44, duel-fuel units performed extremely well, with an average forced outage rate of 5.6% with respect to fuel-related outages. Whereas gas units with firm and non-firm fuel supply arrangements experienced forced outage rates of 13.8% and 33.9%, respectively. While this performance data is representative of only the Winter Storm Elliott period, it does highlight the importance of having secure fuel arrangements to minimize the risk of losing access to fuel supply when it is most urgently needed.

Figure 44. Gas Fuel-Related Outages by Category by Percent of Installed Capacity at Peak



Generation Parameter and Outage Reporting Tools

PJM and members use several tools to collect and manage generator outage data, including the following applications:

- Markets Gateway – Markets Gateway is a PJM tool that allows members to submit generation schedules, as well as other information and data needed to conduct business in the Day-Ahead, Regulation and Synchronized Reserve Markets.
- eDART – eDART (Dispatcher Application and Reporting Tool) is a real-time and forward-looking tool that allows Generation and Transmission Owners to submit generation and transmission outage requests. eDART allows its users to manage their outage data by viewing the status of their outages and obtaining outage reports.
- eGADS – The Generator Availability Data System (eGADS) supports the submission and processing of generator outage and performance data as required by PJM and North American Electric Reliability Corporation (NERC) reporting standards. eGADS is an after-the-fact outage reporting tool used to capture more detailed information about generator outages that are submitted several weeks after the outage.

The generation schedules submitted via Markets Gateway are collections of generator parameter operating limits and offer data. There are three types of schedules that can be submitted, as defined in PJM Manual 11, Section 2.3.4:

- Cost-Based Schedule – Cost-based schedules must comply with limits placed on certain parameters In addition, generation resource cost-based energy offers must be developed in accordance with Manual 15: Cost Development Guidelines and PJM's governing documents.

- Price-Based Parameter Limited Schedule (PLS) – Price-based PLS schedules must comply with limits placed on certain parameters. Price-based PLS energy offers may be market based.
- Price-Based Schedule (non-PLS) – Non-PLS price-based schedules are not subject to the parameter limits defined in and may submit market-based energy offers.

Market Sellers of capacity resources are required to submit schedules in Markets Gateway, based on whether the unit is price based or cost based:

- For Price-Based Units: At least one cost-based schedule is parameter limited and a price-based PLS.
- For Cost-Based Units: At least one cost-based schedule is parameter limited. Certain parameters on cost-based and price-based PLS schedules are subject to defined limits.

It is important for Market Participants to ensure the generator parameter operating limits and offer data are up to date in Markets Gateway. In the event that PJM declares a Maximum Generation Emergency; issues a Maximum Generation Emergency Alert, Hot Weather Alert or Cold Weather Alert; or schedules resources based on the anticipation of a Maximum Generation Emergency, Maximum Generation Emergency Alert, Hot Weather Alert, or Cold Weather Alert for all or any part of such operating day, generation resources are committed on the more economic schedule between their price-based PLS and price-based schedule.

Generation resources are required to report outages in advance of the operating day (when known) and in real time through the eDART application. This reporting must include the cause of the outage, as indicated in PJM Manual 14D. Furthermore, PJM also requires more detailed after-the-fact reporting of all outages in the GADs system by the 20th of the following month.

Generation Owners may augment previous eDART submissions to reflect additional forced outages, but retroactive eDART changes to remove or reduce previously submitted forced outages are not permitted as noted in PJM Manual 10, Section 2.2.1. If a Market Participant needs to remove or minimize a forced outage status previously submitted in eDART, such a revision must be submitted via eGADS and not eDART. PJM does not validate data on causes of outages. If a unit is out of service, it could be liable for a penalty. The eGADS outage is reported to NERC.

As part of the Cold Weather Alert, PJM requires generators to update their availability and operating parameters (notification time, start time, unit cost, etc.) in the Markets Gateway and eDART tools. In 92% of cases where generators failed to perform, PJM either had little or no notice, and very few resources provided updated parameters to reflect known fuel supply constraints or other unit issues.

Lack of timely reporting to PJM's eDART system during Winter Storm Elliott presented challenges for PJM Operations Planning. Many eDART outage submittals lacked sufficient details or inaccurate information, such as cause codes, requiring manual review and outage cause categorization for post-event analysis. PJM and Monitoring Analytics observed a large discrepancy (between 5,000 to 10,000 MW, varying over the period of the event in unplanned outage totals upon initial review of outage data in eDART and GADs). Monitoring Analytics issued a notice to Generation Owners with the recommendation to review and update or submit outage tickets in eDART and GADs to capture outages accurately for post-event analysis. Nearly 300 new outage tickets totaling more than 21,000 MWs of reductions and over 100 revisions to prior tickets totaling more than 14,000 MW of reductions were submitted after the Winter Storm Elliott event.

In addition to Operations Planning, the outage data has many additional use cases, including several of the charts and figures in this report. Having accurate and near real-time eDART outage information helps PJM understand the nature of

the outage and a potential return time to bring the unit back in service. The eGADS data are utilized in the capacity market to determine the availability of a resource in megawatts when clearing. Having updated outage information is expected under normal conditions and even more critical during emergency conditions like Winter Storm Elliott.

Gas Availability Issues

During the morning of Friday, Dec. 23, PJM's Gas-Electric Coordination Team held discussions with many of the interstate gas pipelines serving PJM gas generation to assess system operating conditions. At that point, the cold front had not yet arrived in the eastern part of the PJM system, and, in general, the pipelines in that region were reporting strong operating conditions with high line pack and low-to-moderate demand levels. Meanwhile, the severe cold had already entered the central and Western PJM zones where both gas and electric demand had begun to ramp up quickly corresponding to the rapidly dropping temperatures.

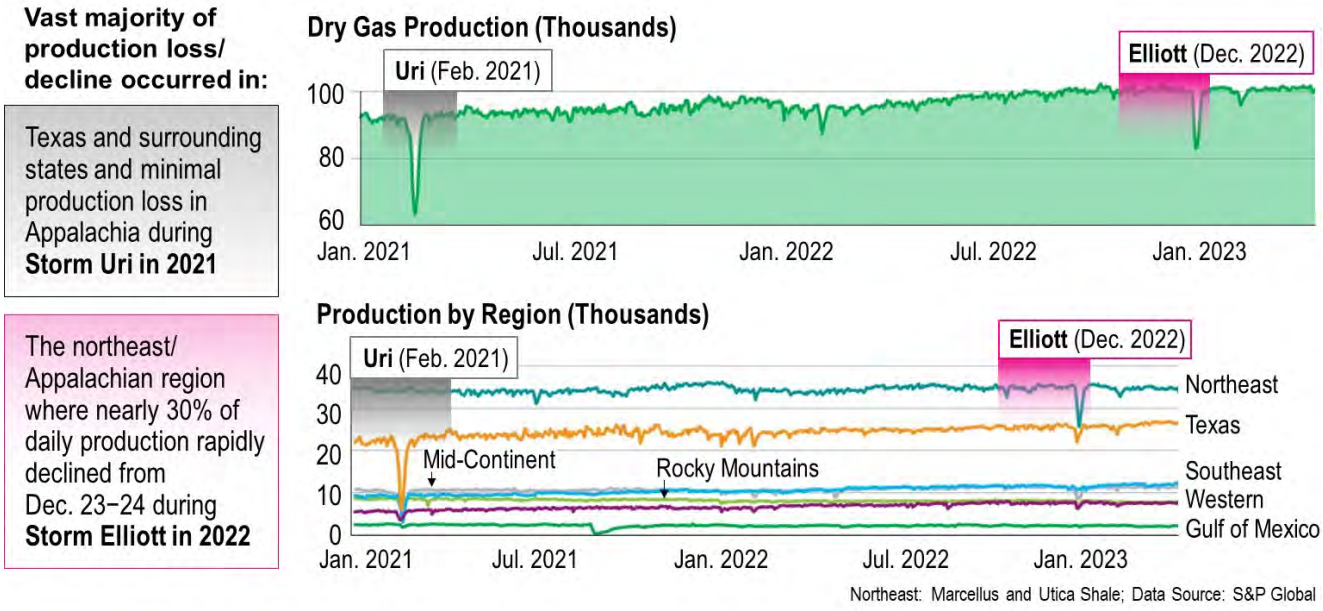
In addition, during this time, several local gas distribution companies (LDCs) began to issue interruption notices for a small number of generators behind their citygates. This is not unexpected during very cold temperatures as LDCs, by nature of their service tariffs, can interrupt gas generation customers in favor of higher priority residential and commercial human needs customers. (Generators served by LDCs make up slightly less than 20% of all gas-fired capacity in the PJM system.) In general, these units are typically smaller combustion turbines with many having dual-fuel capability during the winter months.

The PJM Gas-Electric Coordination Team, as they do each day during the winter months, provided daily gas risk assessment reports to PJM Dispatch to identify which areas of the system may be at higher risk of gas unavailability due to pipeline conditions and restrictions. These assessments also review which units have confirmed gas scheduled on their respective pipelines and compares that to the unit's award commitment to determine if any units haven't scheduled or are short supply. (While gas volumes nominated to generators that are directly connected to interstate pipelines are publically available, nominations to facilities located behind LDC citygates are not and as such not available to PJM. These LDC-served generators represent approximately 20% of the total installed gas generating capacity on the system.) PJM Dispatch uses this information in conjunction with the operating limitations information that the units are providing in eDART and Markets Gateway to have a better understanding of unit availability and which portions of the system are at greater risk of pipeline capacity and gas supply constraints.

While interactions with the pipelines and LDCs are mainly focused on the transportation of natural gas, the supply of natural gas is equally as critical in maintaining reliable fuel deliverability. Natural gas production and midstream facilities, particularly at the wellhead, are subject to freeze-offs during very cold conditions. During Winter Storm Uri in February 2021, there was an extremely large drop in daily gas production due to well freeze-offs in Texas and surrounding states, while very little freeze-off activity occurred in the northeast/Appalachian shale region where most of the gas consumed in PJM originates.

Figure 45 compares natural gas production declines between Uri and Elliott.

Figure 45. Natural Gas Production Declines – Uri Versus Elliott



While there was very little direct impact on PJM during Uri, PJM did reach out to various gas suppliers after Uri to better understand the risk of well freeze-offs and the winterization procedures utilized to mitigate supply loss during cold snaps. The consensus in feedback indicated that natural gas production infrastructure in the northeast was much more hardened and significantly better suited to withstand low temperatures compared to production and processing infrastructure in the south and southwest. Taking that information into consideration and examining past well freeze-offs that actually occurred in the Appalachian region, the best estimate of gas supply loss was around two to three billion cubic feet per day for a one-to-three-day period, which represents approximately 5% to 8% of total northeast daily production. This would not have been unprecedented as it was experienced in prior winter cold snaps, some with temperatures even colder than Elliott. In the end, what ended up occurring was a daily Appalachian gas production loss of 10 to 11 billion cubic feet or approximately 30% of total northeast daily production.

The storm and the rapid onset of cold temperatures heavily impacted natural gas production, particularly in the Marcellus and Utica basins, which are the predominant source of the natural gas procured by gas generation in the PJM footprint. This led to significant loss of gas supply for all downstream gas consumers, particularly larger, more efficient gas-fired power generation units that require nominated supplies flowing at uniform and higher pipeline pressures to operate.

- Supplies from the Appalachian Basin shrank 27% from usual levels, according to reports by Bloomberg.
- Well freeze-offs sent production plunging by more than 20% in Pennsylvania, while output more than halved in Ohio, constraining supplies into the Northeast and the Tennessee Valley.
- There were also losses of pipeline compression that occurred in Ohio and Pennsylvania, which tended to exacerbate gas delivery issues.

Exacerbating the lack of gas supply was the fact that Elliott occurred over a long holiday weekend, which tends to have lower gas supply liquidity. Many gas buyers, especially LDCs and other customers with more predictable gas usage levels, purchase their gas supplies on Friday for the Saturday, Sunday and Monday gas days. Gas generators in many cases need to buy their gas supply each day of the weekend period based on their awarded or anticipated dispatch. With

the majority of gas traded on Friday, the market for gas commodity can become less liquid, resulting in increased supply scarcity and potentially higher intraday gas prices.

Risk of Load Shed

PJM was faced with an unprecedented amount of unplanned generation outages during Winter Storm Elliott. Operations were critical on the evening of Dec. 23 and the morning of Dec. 24. Roughly 47,000 MW of generation was unavailable during the morning hours of Dec. 24. PJM was at an increased risk of load shed approaching the morning peak on Dec. 24. If another large unit was lost or imports from NYISO into PJM were cut, PJM would have considered initiating a Voltage Reduction Action, which would have resulted in approximately 1,700 MW of relief, as captured in PJM Manual 13, Section 2.3 on the Voltage Reduction Summary Table. If necessary, this action would have been followed by a Manual Load Dump Warning to communicate load dump allocations to Transmission Owners, and then a Manual Load Dump Action would be implemented if needed, followed by with the issuance of an EEA-3.

The Voltage Reduction Summary table in PJM Manual 13 should be reviewed with PJM Transmission Owners to confirm current capabilities given the changing composition of load.

Non-Retail Behind-the-Meter Generation (NRBTMG) Performance

The Maximum Generation Emergency Actions issued on Dec. 23 and Dec. 24 triggered the requirement for PJM members to load non-retail behind-the-meter generation[9] (NRBTMG). Although PJM system operators do not directly dispatch NRBTMG units, once a Maximum Generation Emergency Action or Deploy All Resource Action emergency procedure is declared in an area, NRBTMG units located in the area are requested to operate at the unit's maximum net or gross electrical power output, subject to the equipment stress limits for the unit.

Winter Storm Elliott was the first time that PJM evaluated NRBTMG units for emergency event performance. There were 339 NRBTMG units in the RTO that were expected to operate and provide 1,316.1 MW of generation during Winter Storm Elliott. The overall performance of the NRBTMG units in the RTO was also well below expected levels, with NRBTMG unit performance shortfalls totaling 888.8 MW and 635.3 MW for the Dec. 23 and Dec. 24 emergency events, respectively. For both events, the percent performance (i.e., average output during emergency event divided by expected performance) for both the Dec. 23 and Dec. 24 events was less than 50%.

Municipal electric systems, electric cooperatives, and electric distribution companies are permitted to use operating NRBTMG to net against their wholesale load. As a result, the load associated with NRBTMG is not required to carry reserves equal to the target installed reserve margin of 14.9% for the 2022/2023 Delivery Year. NRBTMG units that fail to operate during maximum generation emergency conditions can place an additional strain on the PJM system to provide generation to cover the load that NRBTMG typically serves.

Scheduled outages (full or partial) of NRBTMG units are reported to PJM through the Capacity Exchange tool. PJM does not review or approve NRBTMG scheduled outages. Only scheduled outages during the period of October through May and reported to PJM in advance of an emergency event can be used to excuse the unit for failing to perform as expected and eliminate or reduce their performance shortfall. Excusals for scheduled outages reported in advance of the Dec. 23 and Dec. 24 emergency events were granted to a number of units.

[9] Non-retail behind-the-meter generation (NRBTMG) is behind-the-meter generation that is used by municipal electric systems, electric cooperatives and electric distribution companies to serve load in a wholesale area. A NRBTMG unit delivers energy to a wholesale area's load without using the transmission system.

Failure of NBTMG units in a wholesale area to perform as expected during Winter Storm Elliott does not result in explicit financial penalties to be assessed in a member's PJM bill; however, failure to perform results in implicit penalties to the wholesale area through increased transmission charges for 2024 calendar year and capacity charges for the 2024/2025 Delivery Year. For NRBTMG units in a wholesale area that fail to perform, a netting reduction penalty amount for an emergency event is calculated as 10% of the net unit performance shortfalls in the wholesale area.

A netting reduction penalty amount will reduce the amount of the operating NRBTMG that is allowed to net against the wholesale area load during coincident peak hours during the Nov. 1, 2022, through Oct. 31, 2023, period and result in an upward adjustment to the wholesale area's network service peak load for the 2024 calendar year and obligation peak load value for the 2024/2025 Delivery Year. The total netting reduction penalty amount for the RTO as a result of Winter Storm Elliott was 153.8 MW (89.4 MW for Dec. 23 and 64.4 MW for Dec. 24).

Table 2 summarizes the NRBTMG performance results for the RTO.

Table 2. Dec. 23 and Dec. 24 NRBTMG Performance Results

	Dec. 23, 2022	Dec. 24, 2022
Expected Performance (MW)	1,316.1 MW	1316.1 MW
Unit Performance Shortfalls (MW)	888.8 MW	635.3 MW
Netting Reduction Penalty Amount (MW)	89.4 MW	64.4 MW

Market Outcomes

The Market Outcomes section of the report presents both the Day-Ahead and Real-Time market results for Dec. 23 and Dec. 24, including the ancillary services markets. This section also presents the analysis of Performance Assessment events. Appendix A presents market operations background information.

Day-Ahead Market Results

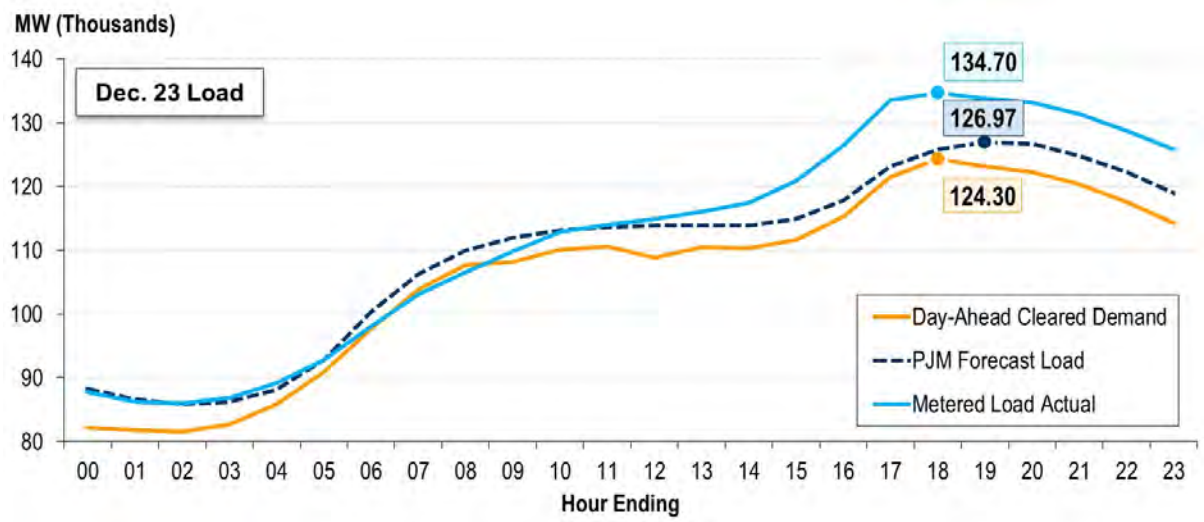
The Day-Ahead Energy Market is a forward market in which hourly clearing prices are calculated for each hour of the next operating day, based on generation offers, demand bids, increment offers, decrement bids, up-to-congestion bids and bilateral transaction schedules submitted into the Day-Ahead Energy Market. Additionally, the Day-Ahead Energy Market also incorporates reliability commitments by PJM system operators and reserve requirements into the analysis. Day-Ahead Energy Market enables participants to purchase and sell energy at binding Day-Ahead LMPs.

The resulting day-ahead hourly schedules, generated by the dispatch run, and Day-Ahead LMPs, generated by the pricing run, represent binding financial commitments to the Market Participants. The Day-Ahead Market settlement is calculated for each Day-Ahead Settlement Interval (currently hourly) based on scheduled hourly quantities resulting from the dispatch run and on Day-Ahead hourly prices resulting from the pricing run.

Day-Ahead Load and Prices

Figure 46 presents the cleared bid demand, including decrement bids and up-to-congestion bids.

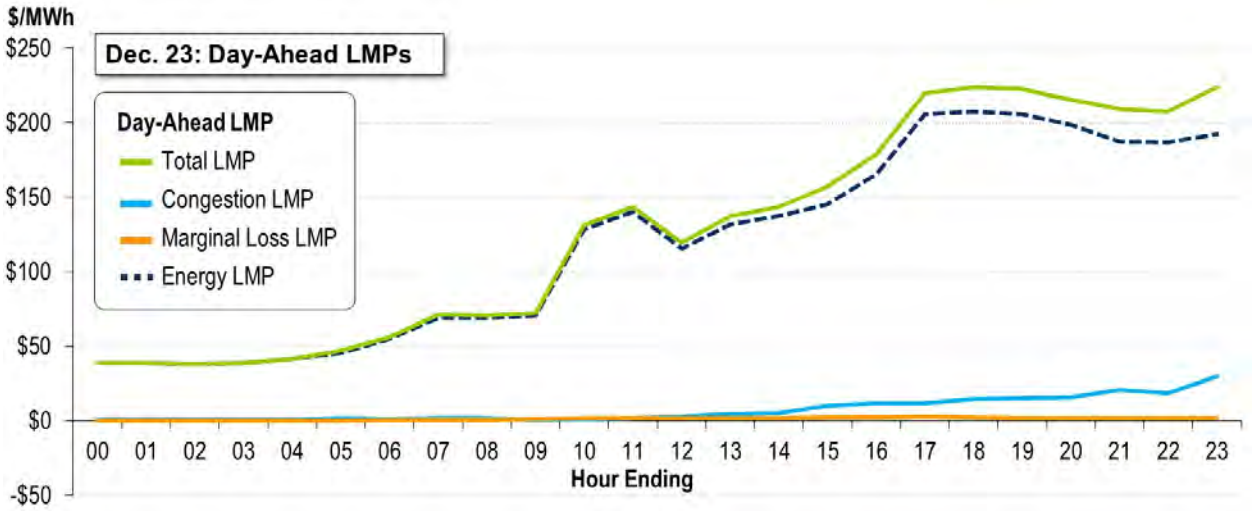
Figure 46. Dec. 23 Day-Ahead Cleared Demand, Forecast Load and Metered Load



For Dec. 23, the day-ahead demand cleared at approximately 124,300 MW, while the actual metered load, including the deployment of Demand Response, came in at approximately 134,700 MW, resulting in a net of approximately 10,400 MW more load in real time than was captured in the Day-Ahead Market cleared demand. PJM's original forecast on Dec. 22 at 18:00 was approximately 126,700 MW, which was about 7,700 MW under the actual load, less Demand Response.

Figure 47 presents the Day-Ahead LMPs for Dec. 23.

Figure 47. Dec. 23 Day-Ahead LMPs

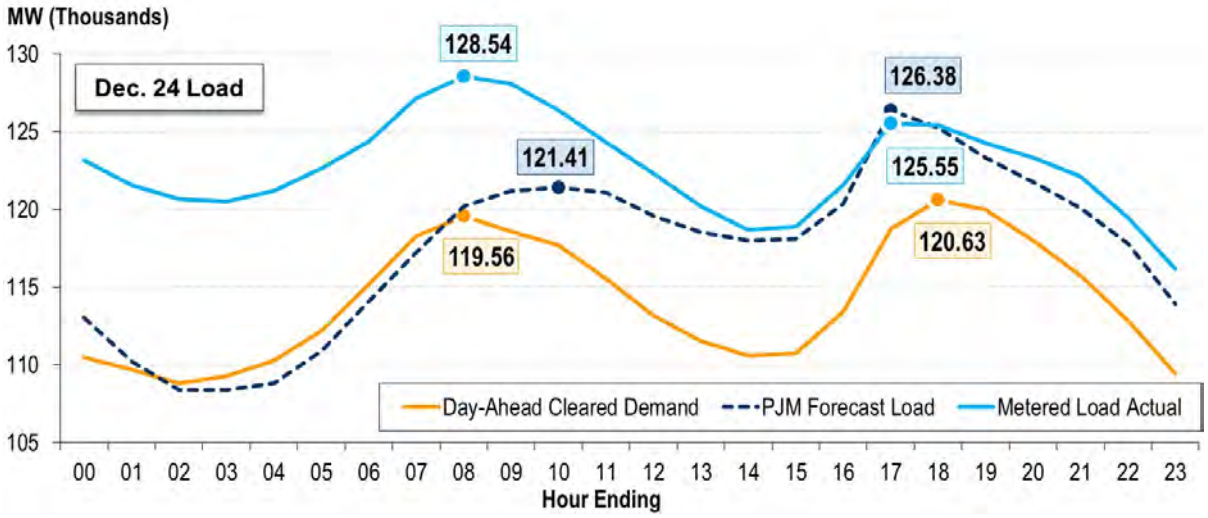


The Day-Ahead LMPs for Dec. 23 were higher than a typical Day-Ahead price, with a peak hourly LMP of $224/MWh. For example, the monthly load-weighted LMP for December 2022 was $93.39/MWh[10]. In the Day-Ahead Market, energy shortage conditions did not occur. LMPs increased in the Day-Ahead Market through the day based on the increasing load levels shown in Figure 47.

[10] Market Monitor Report presentation by Monitoring Analytics. PJM Members Committee Webinar, May 22, 2023.

Figure 48 presents the cleared bid demand, including decrement bids and up-to-congestion bids, and the resulting Day-Ahead prices for Dec. 24.

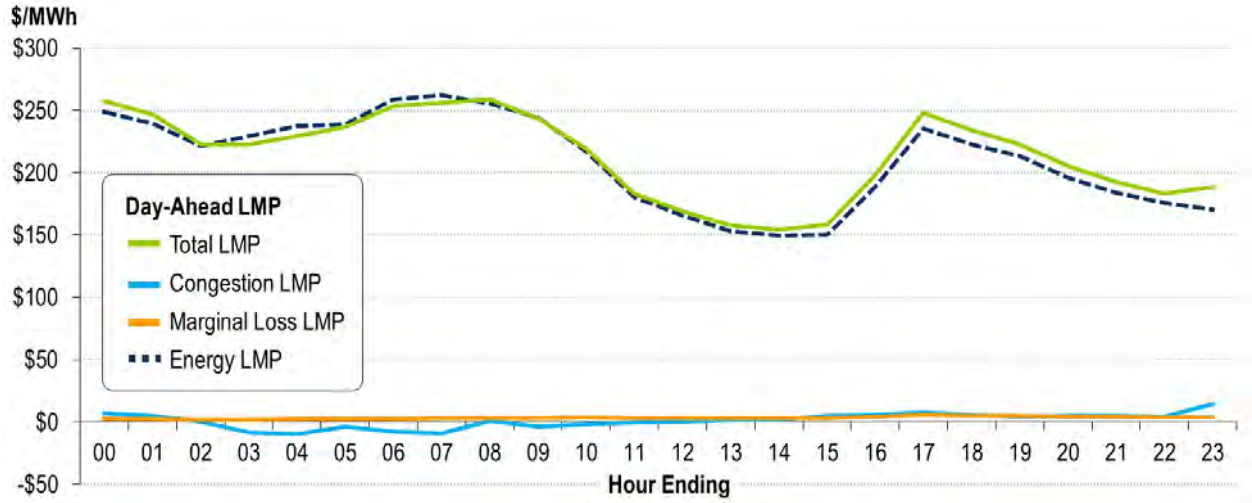
Figure 48. Dec. 24 Day-Ahead Cleared Demand, Forecast Load and Metered Load



On Dec. 24, the day-ahead cleared demand was less than real-time load by approximately 9,000 MW over the morning peak and 4,900 MW over the evening peak.

Figure 49 presents the Day-Ahead LMPs for Dec. 24.

Figure 49. Dec. 24 Day-Ahead LMPs



The Day-Ahead LMPs for Dec. 24 were higher than a typical Day-Ahead price, as noted above, with a peak hourly LMP of $259/MWh. In the Day-Ahead Market, energy shortage conditions did not occur on Dec. 24 either.

Table 3 summarizes the units that were offer-capped in the Day-Ahead Market for the Dec. 23 and Dec. 24 operating days.

Table 3. Dec. 23 & 24 Day-Ahead Offer-Capped Unit Summary

	# of Units	Total MW	Non-Liquid Fuel (MW)	
Dec. 23	32	4,428.1	1,495.5	33.8%
Dec. 24	44	6,444.8	34	0.5%

Virtual Transactions

As described earlier, in the Day-Ahead Market, participants may submit various virtual transactions to hedge risk, mirror physical commitments, or account for their expectations of market conditions. The following three types of virtual transactions are available in the Day-Ahead Market:

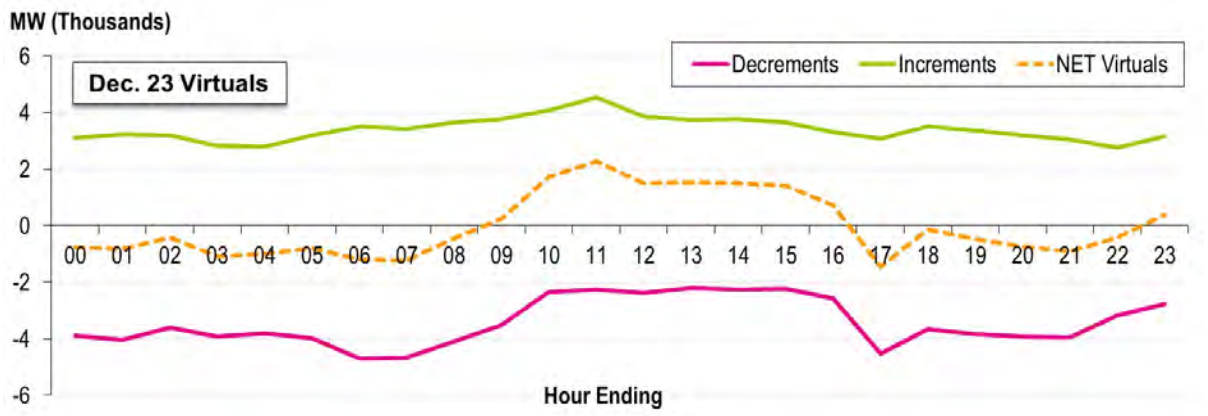
- Increment Offers (INCs) – INCs are submitted in the Day-Ahead Market to sell an amount of energy at a specific location (node) if the Day-Ahead clearing price for that node equals or exceeds the offer price. INCs can be thought of as virtual transactions that emulate generation offers in the Day-Ahead Market. INC transactions are paid the day-ahead LMP for their cleared quantity but must buy out of their position at the real-time LMP. INCs are profitable when the day-ahead LMP is higher than the real-time LMP.

- Decrement Bids (DECs) – DECs are submitted into the Day-Ahead Market as a bid to purchase energy at or below a specified price. DECs can be thought of as virtual transactions that emulate load buy bids in the Day-Ahead Market. DEC transactions pay day-ahead LMP for their cleared quantity and are paid the real-time LMP for the same quantity. Consequently, DECs are profitable when the real-time LMP is greater than the day-ahead LMP.

- Up-to-Congestion Bids (UTCs) – UTCs are bid in the Day-Ahead Market to purchase congestion and losses between two points. UTC bids can be based on the prevailing flow direction where the UTC is buying a position on the Day-Ahead Market congestion, or they can be in the counter-flow direction where they are paid to take a position. The UTC bid consists of a specified source and sink location and a “bid spread” that identifies how much the Market Participant is willing to pay for a congestion-and-loss position between the source and the sink. If the congestion associated with a prevailing flow UTC is less in day-ahead than in real-time, the UTC will be profitable. The opposite is true for counterflow UTCs.

Figure 50 presents the cleared virtual transactions in megawatts, both decrement bids and the increment offers, for the Dec. 23 Day-Ahead Market.

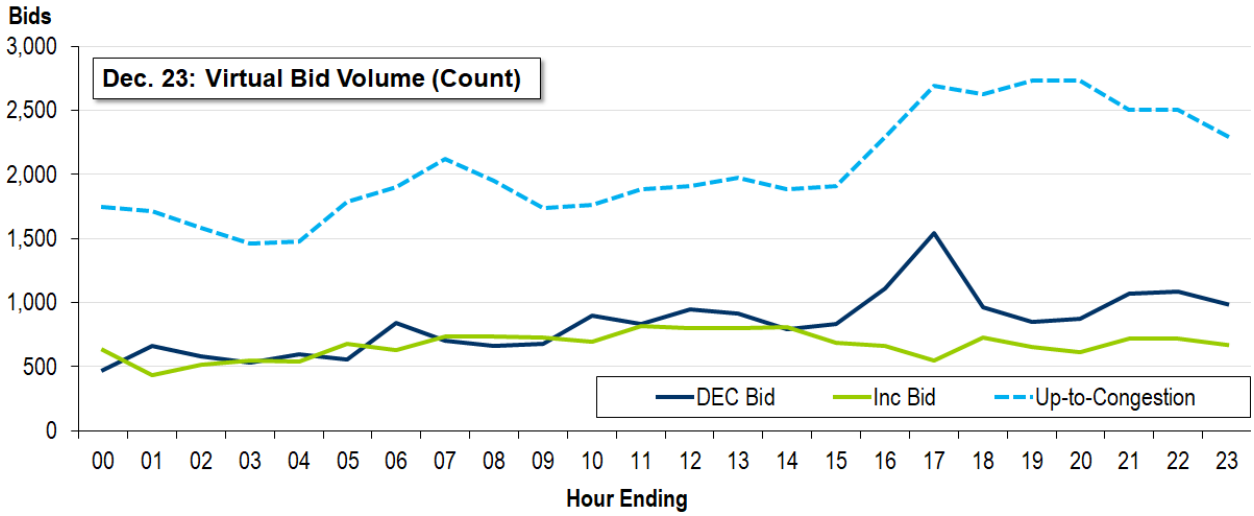
Figure 50. Dec. 23 Cleared Virtual Transactions



As shown in Figure 50, beginning in hour 11 there was approximately 2,000 MW of net virtual generation in the day-ahead solution between hours ending 10:00 and 15:00. Decrement bids in the Day-Ahead Market ranged between 2,200 MW and 4,500 MW and increment offers were between 3,000 MW and 4,500 MW.

Figure 51 presents the virtual transaction volume for Dec. 23.

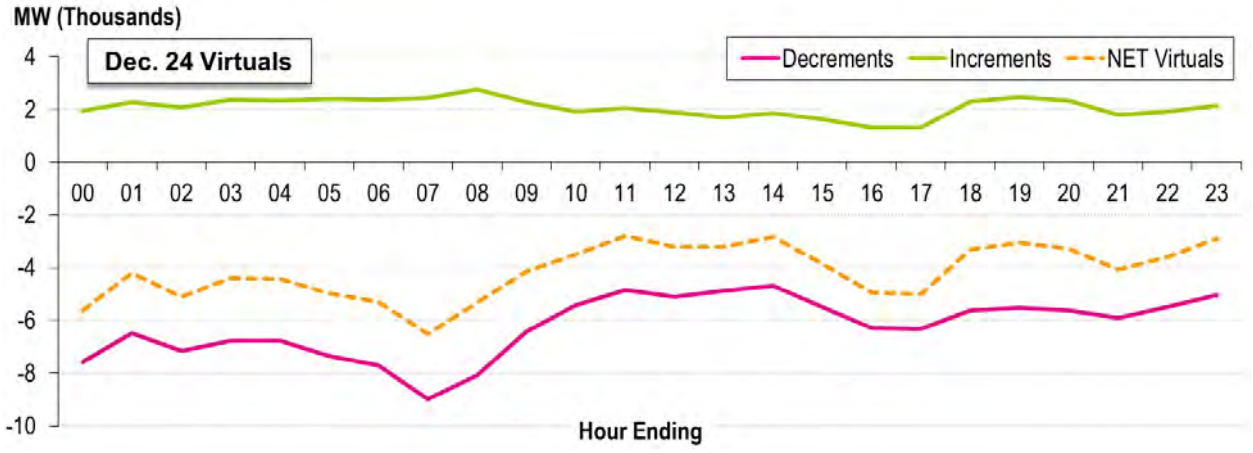
Figure 51. Dec. 23 Virtual Transaction Bid Volume



In the Day-Ahead Market for Dec. 23, there were a maximum of 1,500 individual DEC bids at 15:00 and 814 individual INCs at 11:00.

Figure 52 presents the cleared virtual transactions in megawatts for the Dec. 24 Day-Ahead Market.

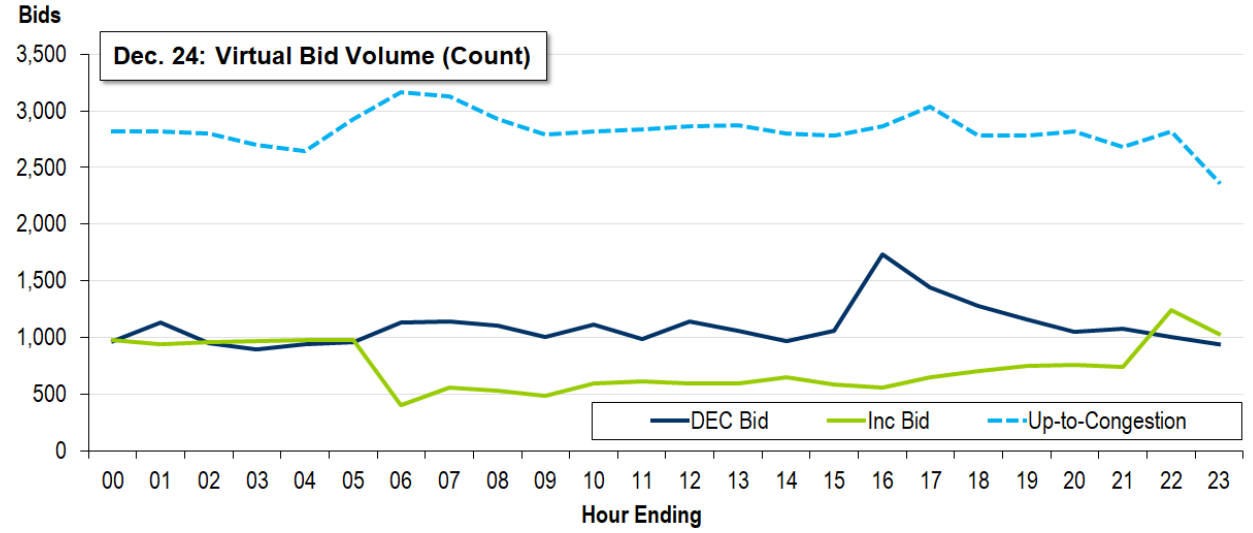
Figure 52. Dec. 24 Cleared Virtual Transactions



As shown in Figure 52, beginning in hour 07:00 there was approximately 6,500 MW of net virtual load in the day-ahead solution. Decrement bids in the Day-Ahead Market totaled approximately 9,000 MW in hour beginning 07:00 and increment bids totaled approximately 2,500 MW beginning in hour 07:00.

Figure 53 presents the virtual transaction volume for Dec. 24.

Figure 53. Dec. 24 Virtual Transaction Bid Volume



In the Day-Ahead Market for Dec. 24, there were a maximum of 1,736 individual DECs at 16:00 and 1,239 individual INCs at 22:00.

In general, demand has been underbid in the Day-Ahead Market on a consistent basis for many years. This is likely in-part due to the desire to purchase some energy on behalf of load at the real-time LMP which can be lower than the day-ahead LMP. This approach carried over to Dec. 23 and Dec. 24, leaving some LSEs exposed to Real-Time Market prices. This could be due to hedging strategies or may be due to uncertainty in load forecasting associated with the expected weather and the holiday weekend. Generators were also exposed to Real-Time Market prices when they were committed in the Day-Ahead Market and were short on their day-ahead commitment in real-time. This can occur when a unit committed in the Day-Ahead Market experiences a forced outage in real-time.

Day-Ahead Reserves

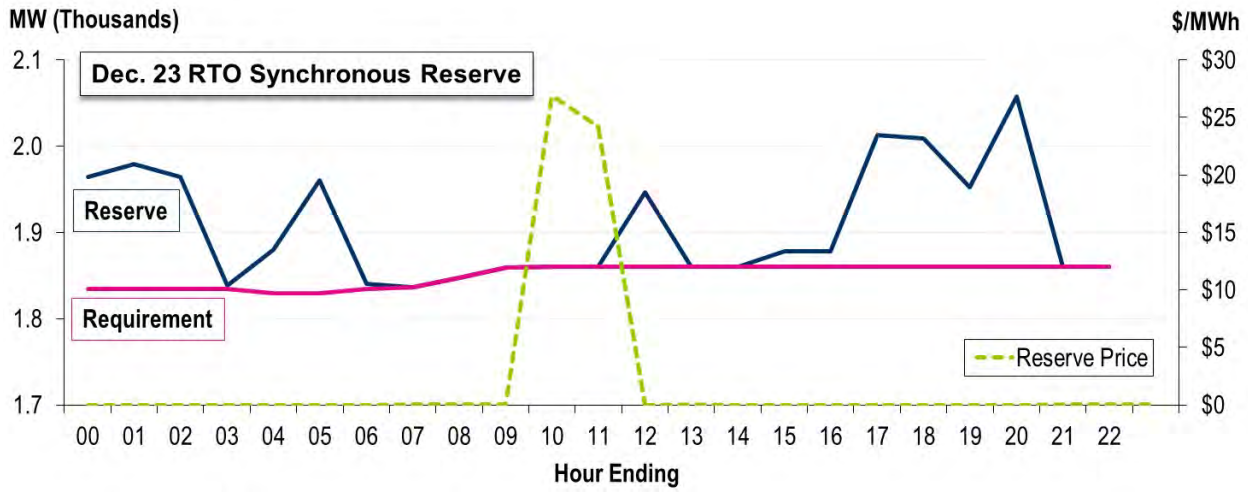
PJM procures resources to meet its reserve requirements, as described earlier in this section, in the Day-Ahead Markets. The clearing of the Day-Ahead Reserve Market results in an hourly price for Synchronized Reserves, Non-Synchronized Reserves and Secondary Reserves for the next day. These prices are posted along with the resource-specific reserve assignments from the dispatch run by 13:30 each day via the PJM Markets Gateway System. The hourly reserve product clearing prices are based upon the offer prices submitted by the committed resources and lost opportunity costs from the pricing run in the Day-Ahead Market clearing software. Lost opportunity cost captures the lost revenues in the Day-Ahead Energy Market a resource may incur by not generating energy but making itself available to provide reserves. For the Dec. 23 and Dec. 24 Day-Ahead Markets, PJM met or exceeded the reserve requirements in all hours.

Offer prices in the PJM reserve markets are limited to the expected value of the non-performance penalty for failing to provide reserves if deployed in real-time. The highest value of the penalty rate was for the month of February 2023, where it was $0.14/MWh.

The reserve markets in the Day-Ahead and Real-Time are modeled such that the highest quality product always has the highest clearing price. For example, the Synchronized Reserve Market Clearing Price (SRMCP) will always be greater than or equal to the Non-Synchronized Reserve Market Clearing Price (NSRMCP) in the same location, because Synchronized Reserve is a higher-quality product than Non-Synchronized Reserve and may be substituted for it. Similarly, the NSRMCP will always be greater than or equal to the Secondary Reserve Market Clearing Price (SecRMCP) in the same location because Non-Synchronized Reserve is a higher quality product than Secondary Reserves and may be substituted for it.

Figure 54 presents the Day-Ahead Synchronized Reserve and prices for Dec. 23.

Figure 54. Dec. 23 Day-Ahead Primary Reserve



PJM met the reserve requirement in the Dec. 23 Day-Ahead Market at zero price, except for the two hours shown in Figure 54. The elevated clearing price for Synchronous Reserves was a result of resources that were backed down to meet the Synchronous Reserve requirement, resulting in non-zero cleared price.

Figure 55 and Figure 56 present Dec. 23 Day-Ahead Primary Reserve and 30-Minute Reserve and prices, respectively.

Figure 55. Dec. 23 30-Minute Reserve and Prices

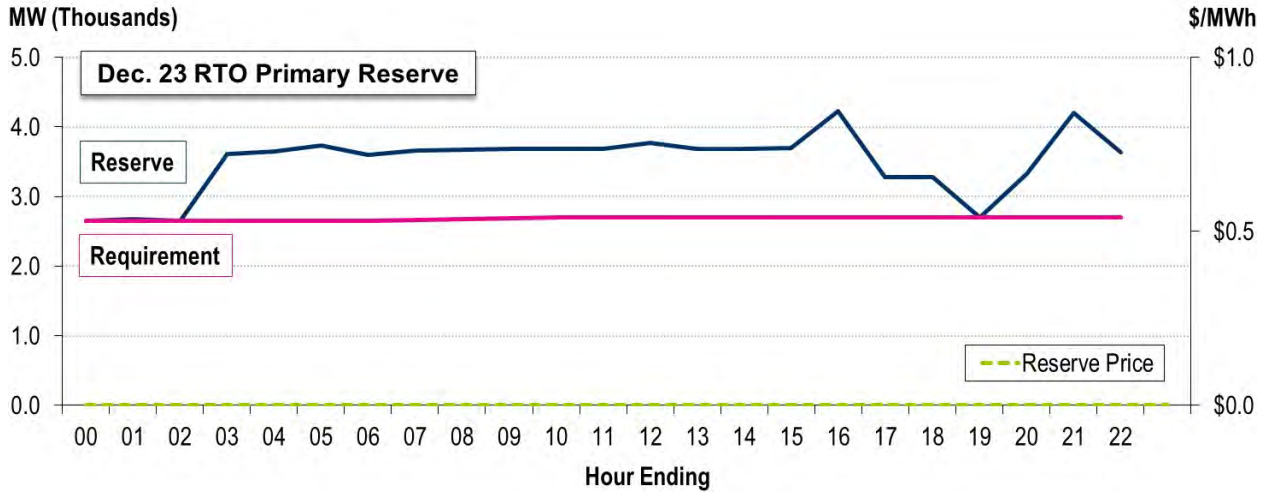
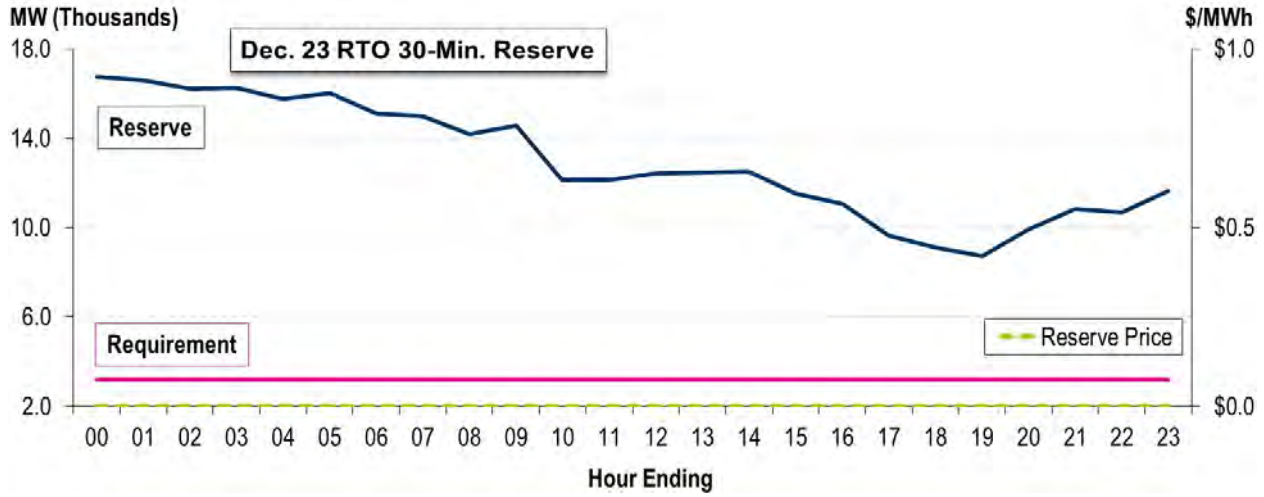


Figure 56. Dec. 23 30-Minute Reserve and Prices



Dec. 23's Day-Ahead Primary Reserve and 30-Minute Reserve prices were zero for all hours, signaling that there were sufficient resources with offers indicating they could meet the requirements to provide those reserves with no adjustment to their schedules in the Day-Ahead Market.

Figure 57, Figure 58 and Figure 59 present the Dec. 24 Day-Ahead Synchronized Reserve, Primary Reserve and 30-Minute Reserve and prices, respectively.

Figure 57. Dec. 24 Day-Ahead Synchronized Reserve

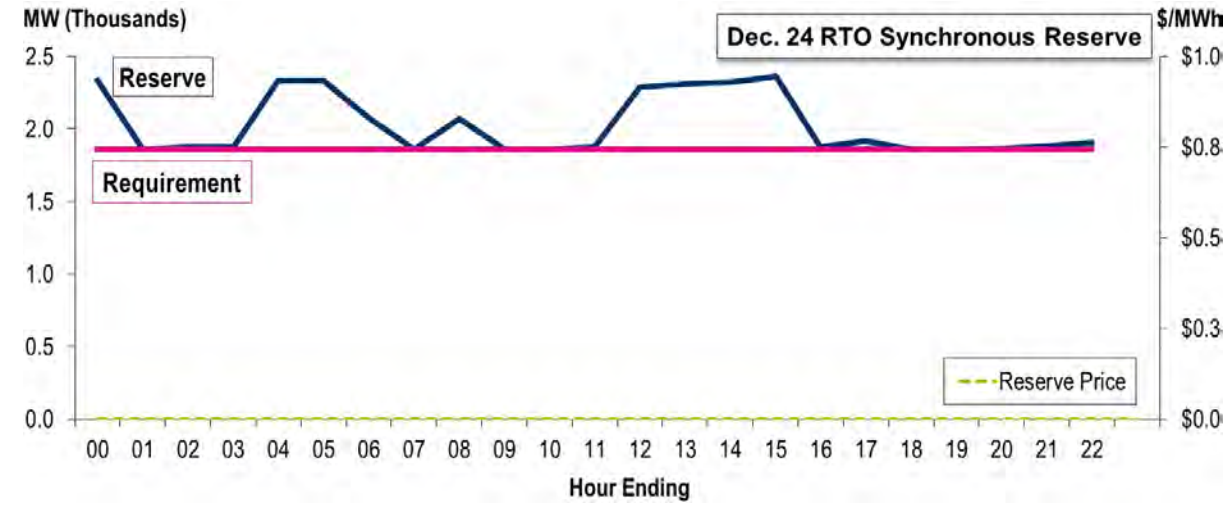


Figure 58. Dec. 24 Day-Ahead Primary Reserve

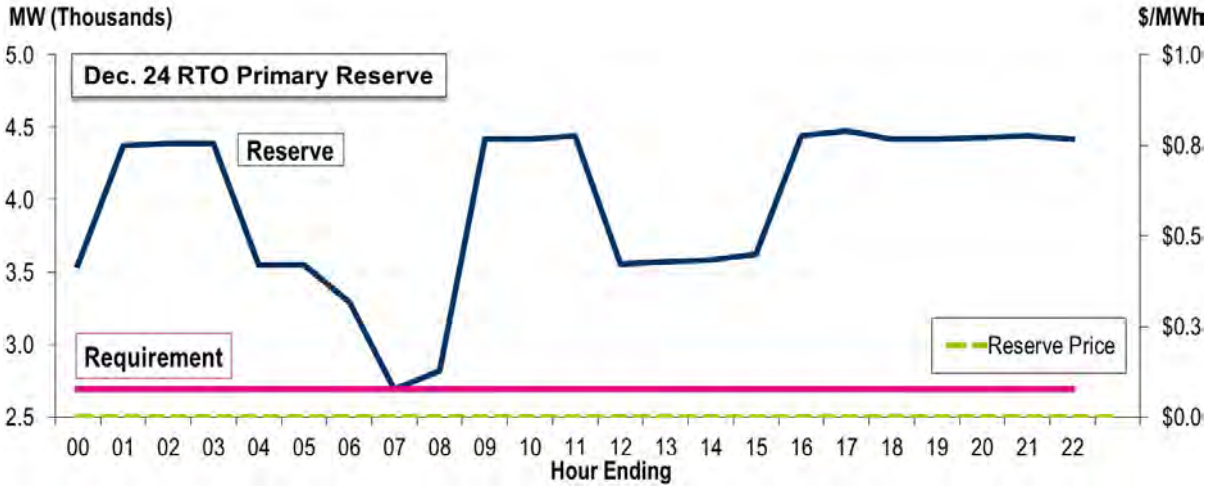
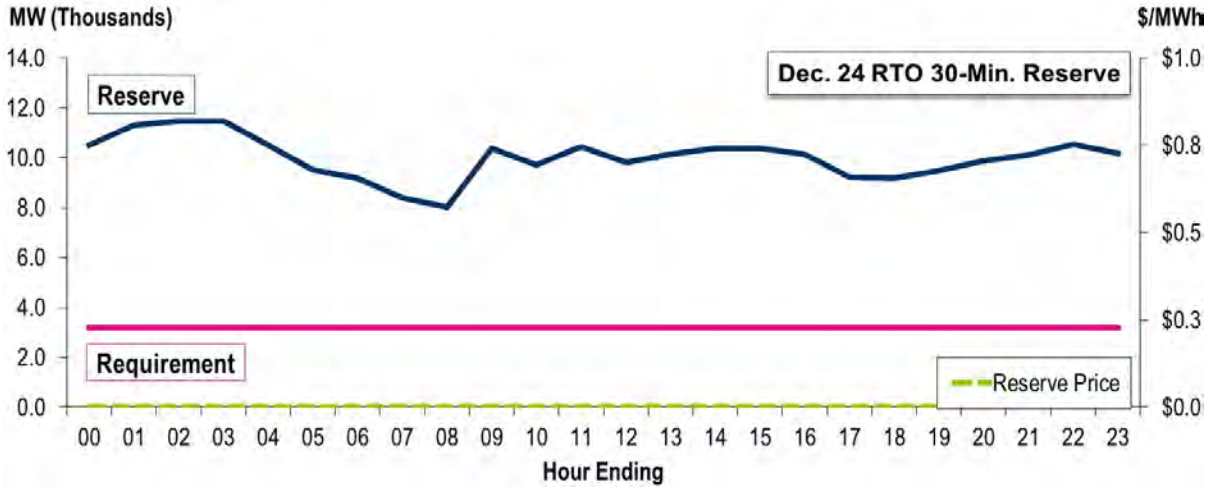


Figure 59. Dec. 24 30-Minute Reserve & Prices



Note that the Dec. 24 Day-Ahead Reserve Requirements were met at zero cost for the entire day, indicating that there were sufficient resources available to meet these requirements without adjusting their schedules based on the offer parameters submitted into the Day-Ahead Market.

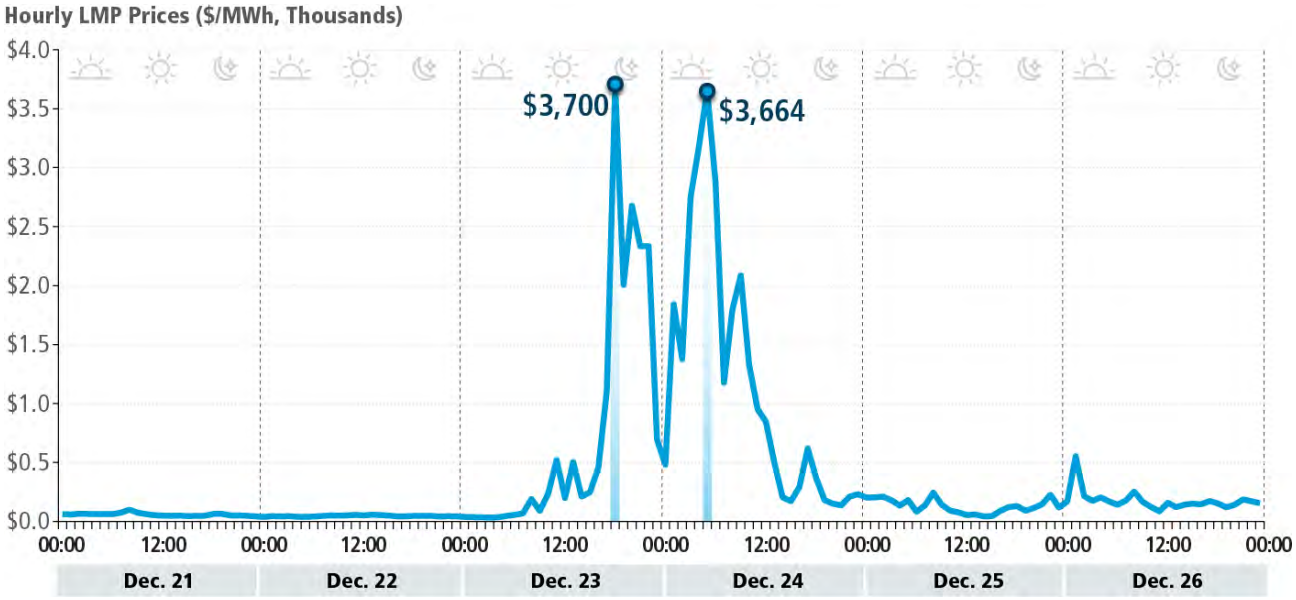
Real-Time Market Results

The Real-Time Energy Market uses the Real-Time Security Constrained Economic Dispatch (RT SCED) program, known as the "dispatch run," to determine the least-cost solution to balance supply and demand. The dispatch run considers resource offers, forecasted system conditions and other inputs in its calculations.

Real-Time LMPs and Regulation and Reserve Clearing Prices are calculated every five minutes by the Locational Price Calculator (LPC) program, in a process referred to as the pricing run, and are based on forecasted system conditions and the latest approved RT SCED program solution. Real-time prices are used to settle quantity deviations from day-ahead schedules in what is referred to as a balancing settlement.

Figure 60 presents the average Real-Time LMPs for Dec. 23 and Dec. 24.

Figure 60. Dec. 23 and Dec. 24 Hourly System Energy Prices



On Dec. 23 and 24, Real-Time LMPs across the system rose as high as $3,700/MWh on both days and were driven by fuel costs, stressed system conditions including reserve shortages, multiple emergency procedures declared by PJM operators, a high generator forced outage rate, and higher-than-expected load. In comparison, the average Real-Time LMP for the month of December 2022 was $122/MWh, while the average LMP for Dec. 21–26 was $386/MWh.

Congestion Impacts

A transmission constraint occurs when a physical limitation of a transmission facility is reached during normal or contingency system operations. When this occurs, the most economic generation cannot be delivered to the load due to physical limitations on transmission facilities. As a result, when there is a transmission constraint, more expensive generation that is electrically closer to the load must be dispatched in order to ensure that flows on transmission facilities are maintained within their operating limits.

To determine which generators have the most cost-effective benefit on relieving a transmission constraint, PJM calculates the dollar-per-megawatt effect of each generator on a transmission constraint and redispatches the lowest cost generators first to control the transmission constraint. The cost that the RT SCED will incur to control a transmission constraint is limited to the level of the Transmission Constraint Penalty Factor (TCPF), typically $2,000/MWh. The TCPF not only caps the cost of controlling actions used to control a transmission constraint but it is also the price level used to indicate that a transmission constraint cannot be controlled. This occurs when the actual or post-contingency flow on a transmission constraint exceeds the limit operators are controlling to.

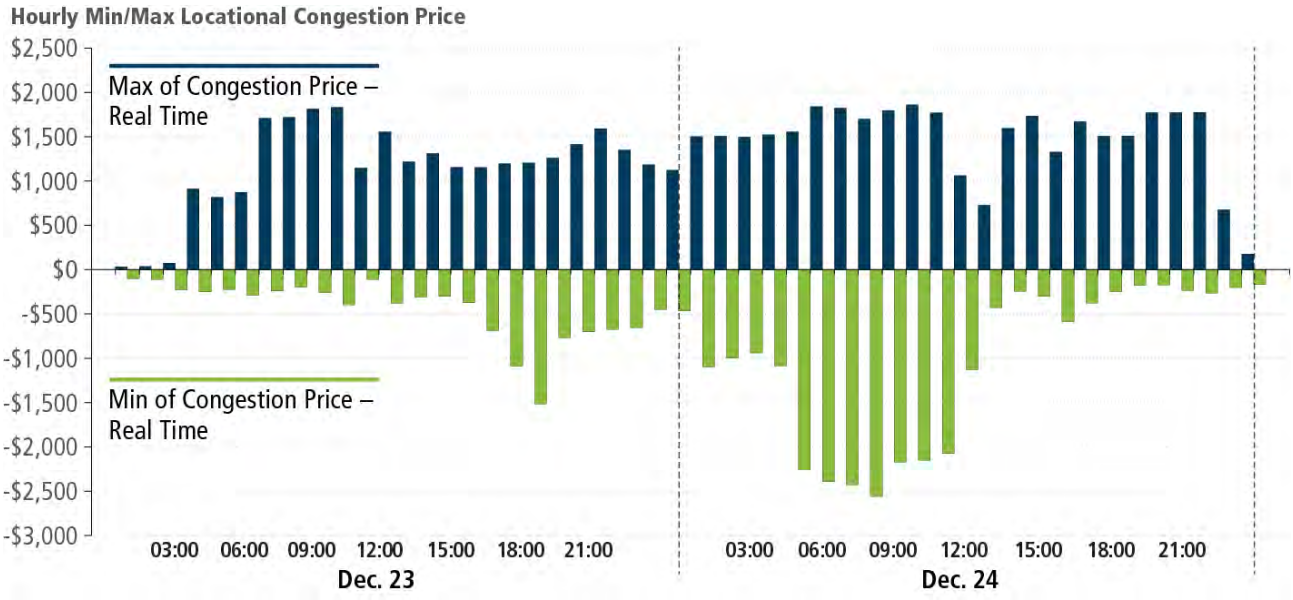
The underlying goal and intent of reflecting the TCPF in LMPs is to provide market signals that incentivize supply and/or load response to help relieve a constraint in the short term, while also incentivizing the development of additional supply, load response and/or transmission upgrades through long-term investments. Use of the TCPF, therefore, generally results in prices that signal short-term responses and longer-term investment that would be beneficial to the reliability of the transmission system and therefore have the intended impact.

On Dec. 23, 27 of the 35 active constraints in SCED bound at TCPF for at least one five-minute interval, indicating multiple locations of local scarcity within the PJM footprint. On Dec. 24, 28 of the 42 active constraints bound at the TCPF for at least one five-minute interval. While PJM maintains the ability to adjust the default level of the TCPF, no adjustments were made during Winter Storm Elliott, as all system constraints were effectively being controlled by resources available to PJM system operators.

The system pricing effects of the TCPF, and congestion in general, is locational. The TCPF is used to determine the Marginal Value of a transmission constraint when sufficient controlling actions do not exist to control the constraint at or below the applicable TCPF.

Figure 61 presents the impacts of congestion on the Real-Time Locational Congestion Price for Dec. 23 and Dec. 24.

Figure 61. Dec. 23 and Dec. 24 Congestion Prices



The locational aspect of load to constraints ultimately impacts pricing, as shown in Figure 62. Zonal prices reached as high as approximately $4,300 on Dec. 24.

Table 4 presents the binding constraints on high-voltage equipment that had a broader system impact on locational pricing on Dec. 23 and Dec. 24.

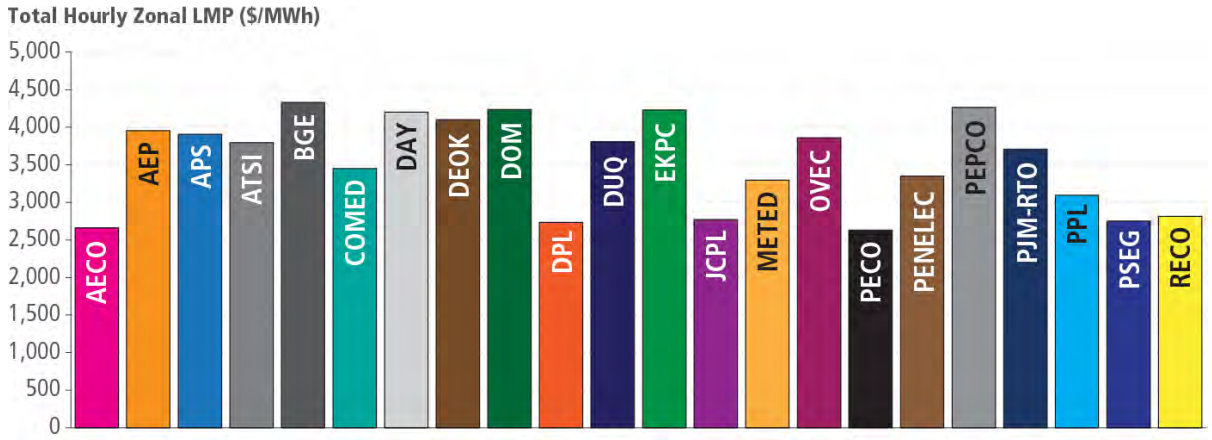
Table 4. Dec. 23 and Dec. 24 Binding Constraints on High-Voltage Equipment

Equipment Name (500 kV and Above)*	Zone	# of Intervals at TCPF	Dec. 23 (EPT)	Dec. 24 (EPT)
TRANSFER INTERFACE: AEP-DOM	N/A	129	09:35–22:30	00:05–23:50
JUNIATA 1 XFORMER H 500 KV	PPL	73	19:20–21:25	01:30 04:35–09:55
CONASTON-PEACHBOT 5012B 500 KV	BC	21	22:20–23:45	00:40
CABOT-KEYSTONE 5002B 500 KV	APS	1	12:25	
BROADFO2 T6 XFORMER H 765 KV	AEP	28	09:15–11:10 12:30–12:45 12:55	

Note: A complete list of binding constraints is available at Data Miner.

Figure 62 presents the locational impact of congestion for a sample interval on the evening of Dec. 23.

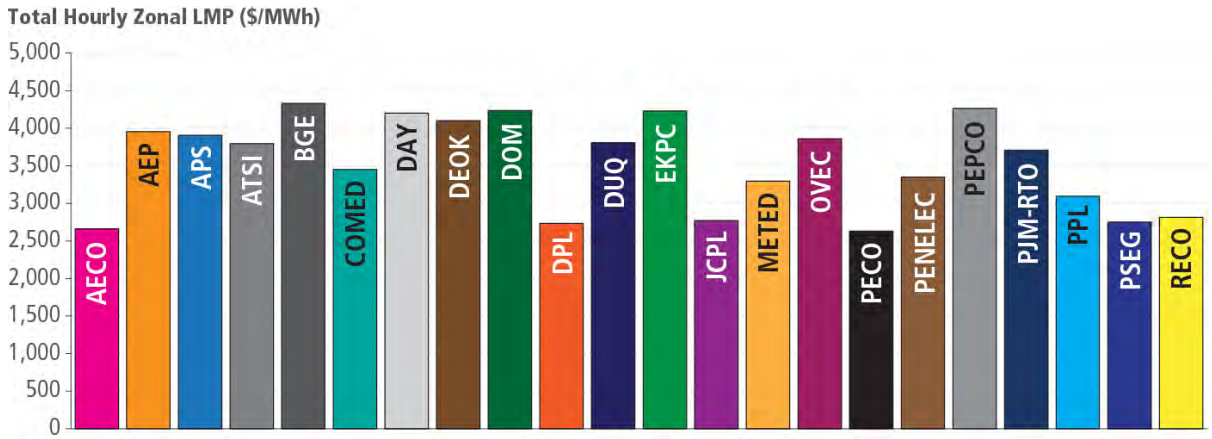
Figure 62. Dec. 23 17:00 Total Hourly Zonal LMP



Given that the System Energy Price cannot rise above $3,700/MWh, the difference can be attributed primarily to the impacts of congestion.

Figure 63 presents the locational impact of congestion for a sample interval on the evening of Dec. 24.

Figure 63. Dec. 24 08:00 Total Hourly Zonal LMP



FTRs were fully funded during the extent of Winter Storm Elliott. From Dec. 23 through Dec. 25, FTR target credits totaled $99,017,903.99. Day-ahead congestion, which is the sum of the target and surplus, over that same time period was $130,319,840.29, resulting in a $33,919,216.32 surplus. For further information on FTR accounting, please see PJM Manual 6, Section 8.

Balancing Congestion is captured in Figure 64 for the period between Dec. 20 and Dec. 26.

Figure 64. Balancing Congestion Dec. 20–26



On Dec. 23, Net Balancing Congestion was $22,134,094 and $23,504,649 for Dec. 24. Net Balancing Congestion is positive for both days, indicating some active real-time constraints were not triggered in the day-ahead solution. The reason for the imbalance is, in part, tied to the lower cleared load in the Day-Ahead Market compared to the actual load realized during the operating days of Dec. 23 and Dec. 24.

Real-Time Load and Prices

On both Dec. 23 and Dec. 24, PJM had insufficient reserves available to meet the reserve requirements. If during the execution of the pricing run, the Locational Pricing Calculator (LPC) determines that a reserve shortage exists, PJM

deems this to be a reserve shortage, triggering shortage pricing. Shortage pricing is a market rule that ensures energy and reserve prices reflect the state of the system, both leading up to and during times of reserve shortages. A reserve shortage occurs when there are insufficient resources available to maintain the balance of generation, load and reserve requirements. PJM implements shortage pricing through the inclusion of the applicable Reserve Penalty Factors in the Real-Time LMP and reserve pricing calculations.

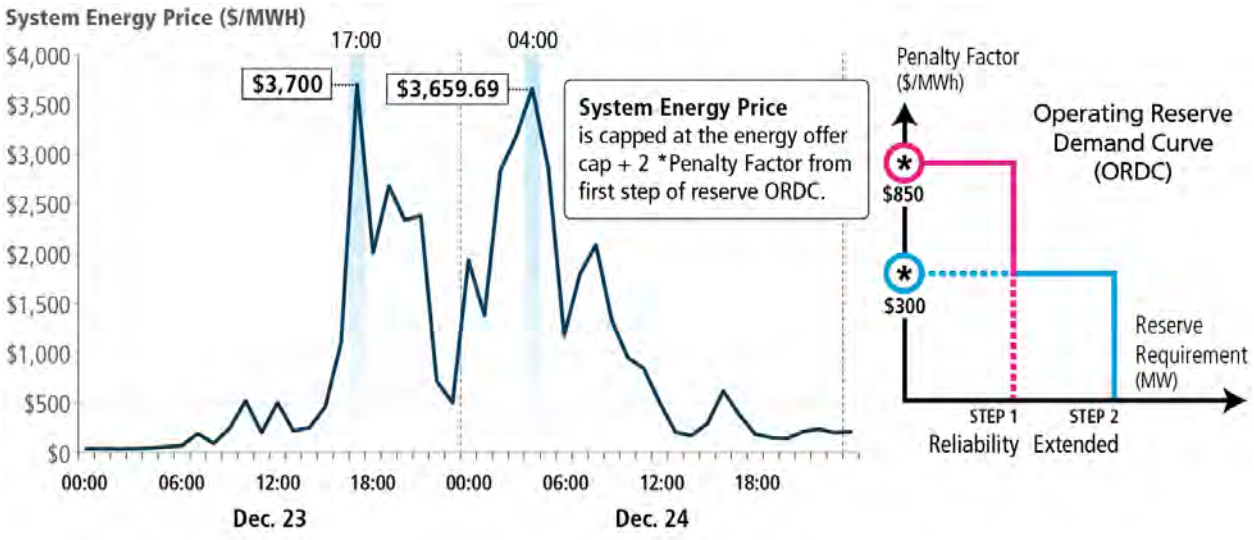
PJM uses Operating Reserve Demand Curves (ORDCs) to set the demand and willingness to pay for each of its reserve products. Like the TCPF, the ORDCs contain Reserve Penalty Factors that function as a cap on the $/MWh cost willing to be incurred to maintain a specific reserve requirement in a specific location. All Reserve Penalty Factors are currently set at either $300/MWh or $850/MWh depending on the segment of the ORDC.

The maximum reserve prices are capped as follows:

- Synchronized Reserves are capped at two times the penalty factor ($1,700).
- Non-Synchronized Reserves are capped at 1.5 times the penalty factor ($1,275).
- Secondary Reserves capped at one time the penalty factor ($850).

Figure 65 presents the System Energy Price on Dec. 23 and Dec. 24:

Figure 65. Dec. 23 and Dec. 24 System Energy Price



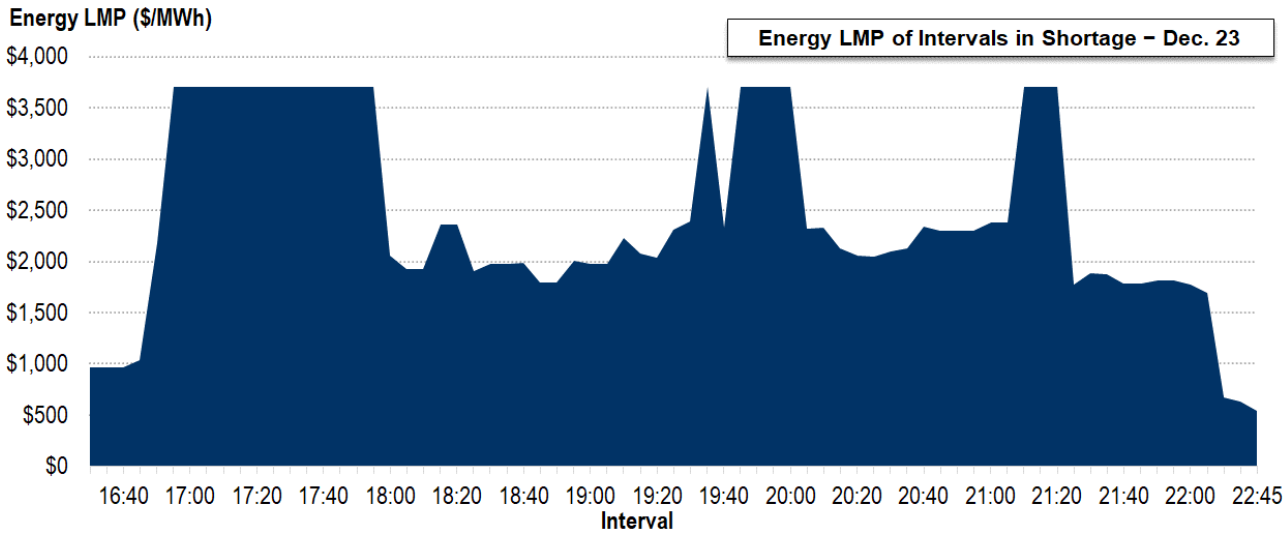
There were 71 shortage intervals approved by PJM Dispatch between 16:30 and 22:45 on Dec. 23. Table 5 reflects the breakdown by Reserve Sub-Zones.

Table 5. Shortage Intervals by Reserve Sub-Zones

	Reserve Penalty Factors
45	MAD & RTO – Primary
21	MAD & RTO – Primary & Synchronized
2	MAD & RTO – Primary & RTO – Synchronized
3	RTO Primary

Figure 66 presents the LMPs during the shortage intervals on Dec. 23.

Figure 66. Dec. 23 LMPs During Shortage Intervals



PJM currently has rules in place that place a cap on the System Energy Price of $3,700/MWh. This cap was reached during various intervals on Dec. 23 as shown Figure 66. Total LMPs exceeded $3,700/MWh in some locations during these shortage intervals due to the addition of congestion and losses.

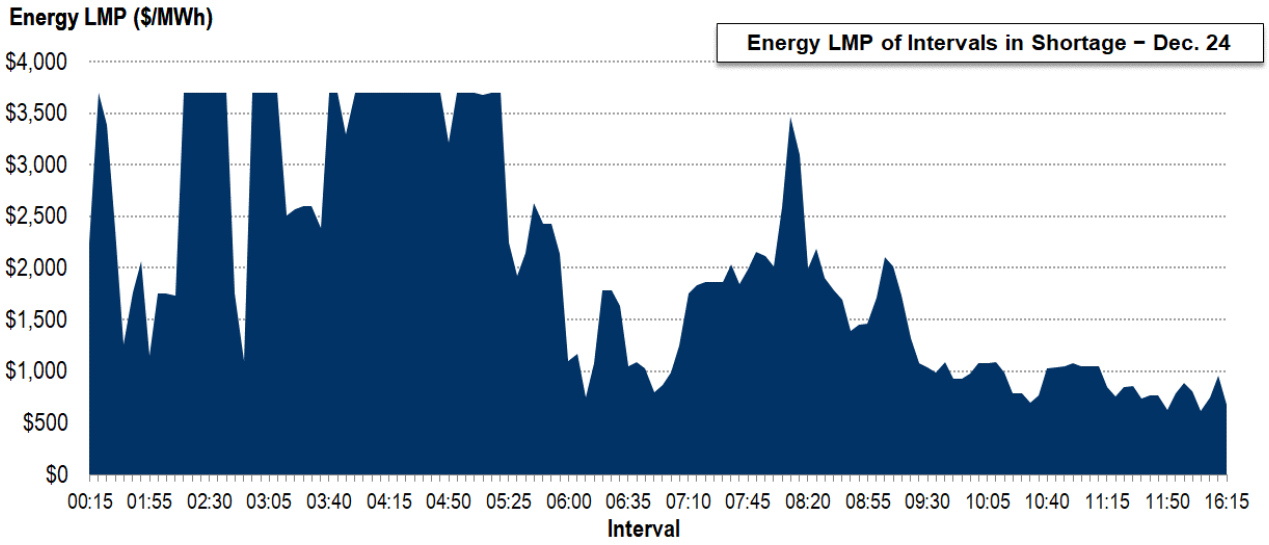
There were 134 shortage intervals approved by PJM Dispatch between 00:15 and 16:15 on Dec. 24. Table 6 presents the breakdown of the shortage intervals by Reserve Sub-Zones.

Table 6. Shortage Intervals by Reserve Sub-Zones

	Reserve Penalty Factors
69	MAD & RTO – Primary
37	MAD & RTO – Primary & Synchronized
16	MAD & RTO – 30-Minute
1	MAD & RTO – Primary & RTO – Synchronized
11	RTO Primary

Similarly, Figure 67 presents the LMPs during the shortage intervals on Dec. 24.

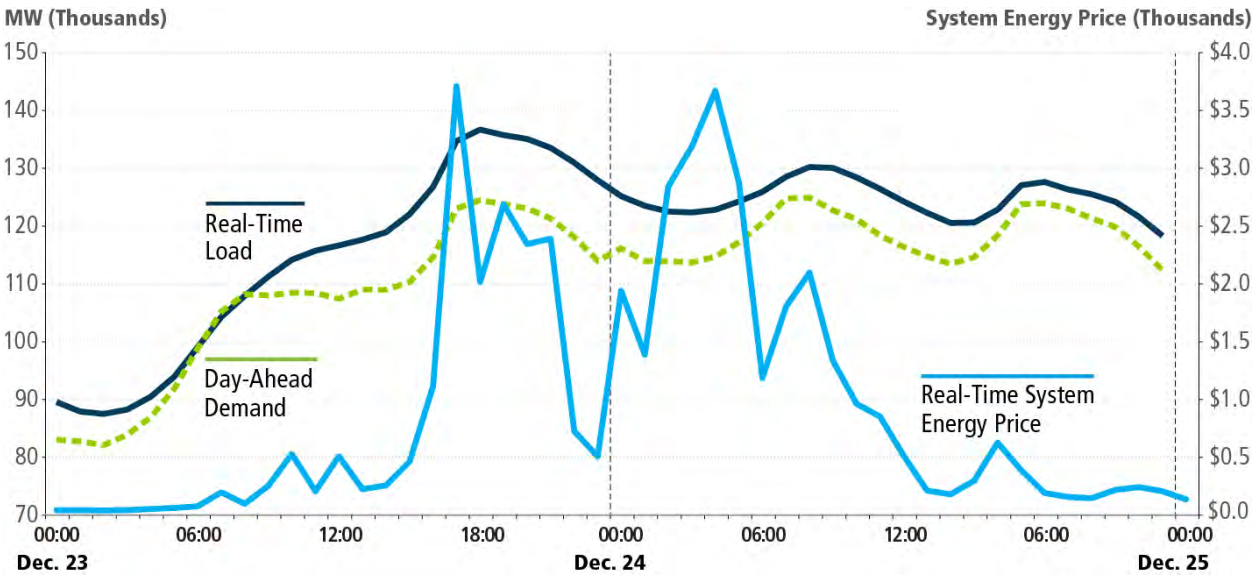
Figure 67. Dec. 24 LMPs During Shortage Intervals



On Dec. 24, the System Energy Price was $3,700/MWh during shortage intervals, as shown in Figure 67. During these intervals, there were locations on the system where LMP exceeded this price level when congestion and losses were also included.

Starting in the evening on Dec. 23, PJM experienced elevated pricing for energy and reserves, consistent with the multiple emergency procedures that were initiated due to extreme system conditions. Factors driving those extreme conditions included higher-than-anticipated loads and unprecedented forced generator outages. As a result, Real-Time Market operations accurately reflected multiple five-minute intervals with strained power balance, locational congestion management and extended periods of shortage pricing. Figure 68 overlays the System Energy Price, day-ahead forecasted load and real-time load.

Figure 68. System Energy Price, Day-Ahead Forecasted Load and Real-Time Load

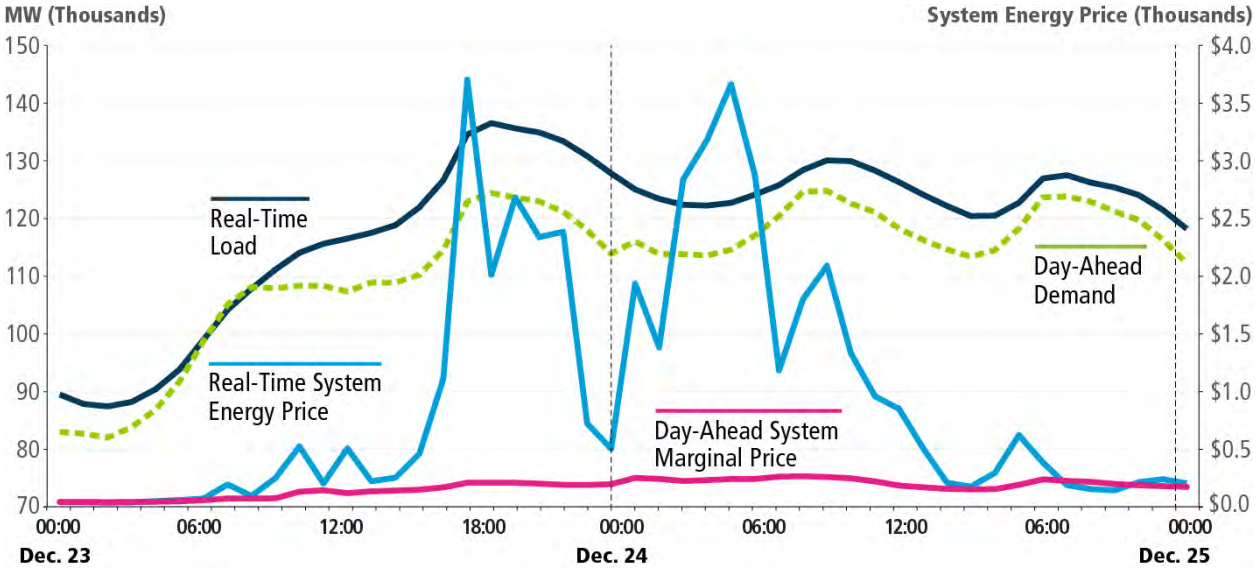


Real-Time LMPs are calculated based on five-minute intervals. Both generation and emergency Demand Response resources can and did set the price.

Day-Ahead Versus Real-Time Prices

Figure 69 presents the average day-ahead hourly load and prices compared to the real-time average load and prices.

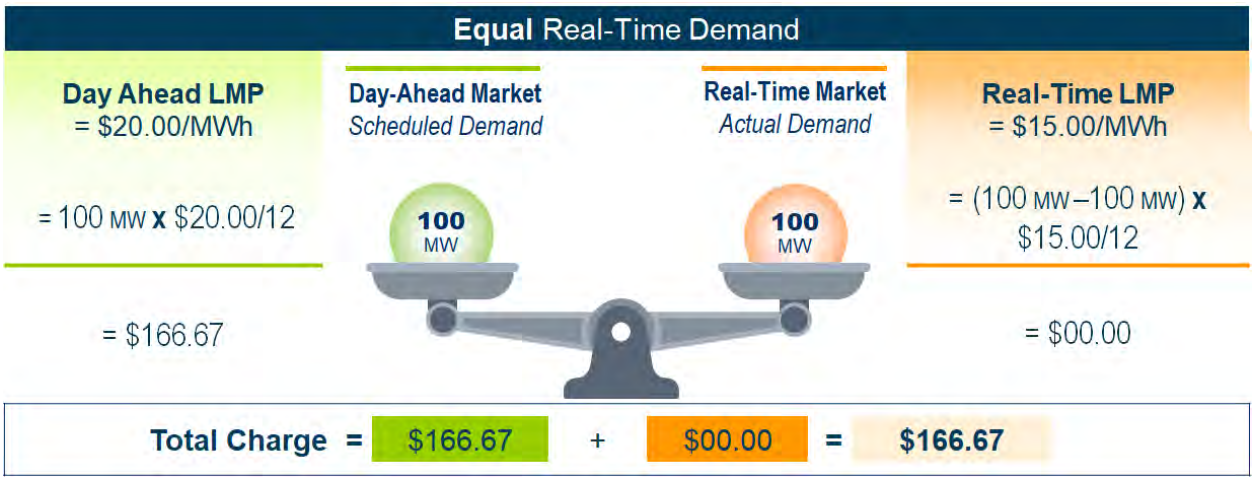
Figure 69. Day-Ahead and Real-Time Load and Day-Ahead and Real-Time Hourly System Energy Price



There is a significant difference between the day-ahead and the actual real-time load (approximately 12,172 MW), as shown in Figure 69. The difference between the Day-Ahead and Real-Time Market prices, due primarily to the unavailability of generation in real-time and under-forecasting of load in day-ahead, creates a potential for exposure to Real-Time pricing. Cleared day-ahead demand for Dec. 23 was 10,400 MW lower than the actual metered load realized at the peak. In comparison, cleared day-ahead demand for Dec. 24 was approximately 9,000 MW lower than the actual metered load realized during the morning peak. The demand that was cleared in the Day-Ahead Market was subject to the Day-Ahead LMP of $207/MWh on Dec. 23 and $262/MWh on Dec. 24. Real-time load that was not hedged in the Day-Ahead Market during the peak periods on these days was exposed to Real-Time LMPs of approximately $3,700 in both instances.

Figure 70 presents an example of a settlement example for an LSE that is fully hedged.

Figure 70. Fully Hedged LSE Settlement Example



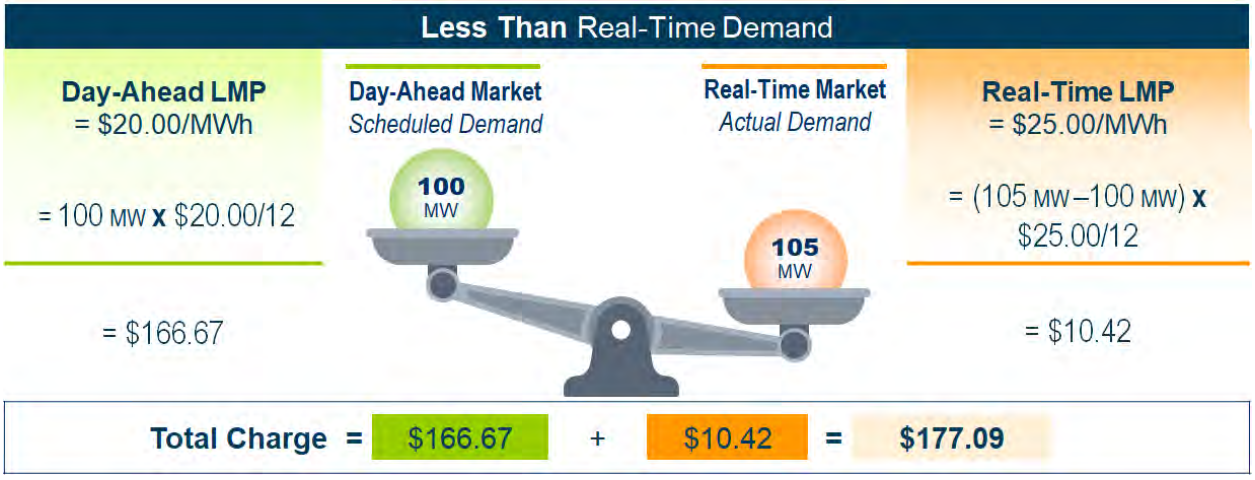
In Figure 70, the LSE submitted a 100 MW bid in the Day-Ahead Market. The Day-Ahead Market cleared at $20.00/MWh. The Day-Ahead Market settlement for this five-minute interval is the day-ahead scheduled demand multiplied by the Day-Ahead LMP divided by 12 (there are 12 five-minute intervals in an hour), or $166.67.

In the Real-Time Market, the LSE's actual demand is 100 MW. The balancing settlement for this five-minute interval is the difference between Real-Time Market actual demand and the Day-Ahead Market scheduled demand, multiplied by the Real-Time Market LMP divided by 12. Since the LSE's Real-Time Market actual demand and the Day-Ahead Market scheduled demand are both 100 MW, the LSE is fully hedged and is not exposed to the Real-Time Market prices. The Real-Time Market settlement is $0.00.

The total charge for this LSE for this sample five-minute interval is the Day-Ahead Market charge plus the Real-Time Market charge, or $166.67.

Figure 71 presents a settlement example for an LSE that is under-hedged.

Figure 71. Under-Hedged Load Settlement Example



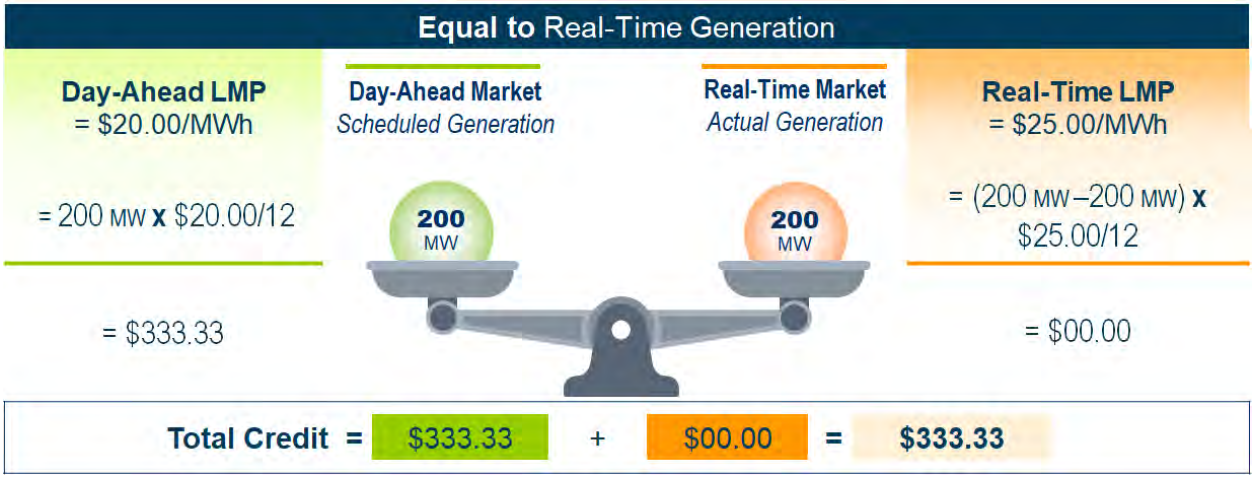
In Figure 71, the LSE submitted a 100 MW bid in the Day-Ahead Market. The Day-Ahead Market cleared at $20.00/MWh. The resulting Day-Ahead Market settlement for this sample five-minute interval is the Day-Ahead scheduled demand multiplied by the Day-Ahead Market LMP, in this case the Day-Ahead Market settlement is $166.67.

In real time, the Load Serving Entity's actual demand is 105 MW, 5 MW greater than the Day-Ahead Market. Therefore, the LSE is exposed to the Real-Time Market prices or is "under-hedged" for the additional 5 MW. The LSE purchases the 5 MW at the Real-Time LMP. The balancing settlement for this sample five-minute interval is the difference between the Real-Time actual demand minus the Day-Ahead Market scheduled demand. In this case, the LSE scheduled 100 MW in the Day-Ahead Market and the actual demand is 105 MW. The Real-Time Settlement is therefore 5 MW multiplied by the Real-Time Market LMP of $25.00/MWh, divided by 12, for a total of $10.41.

The total charge for this LSE for this five-minute interval is the Day-Ahead Market charge plus the Real-Time Market charge, or $177.09

Figure 72 presents a settlement example for a generator that is fully hedged.

Figure 72. Fully Hedged Generator Settlement Example



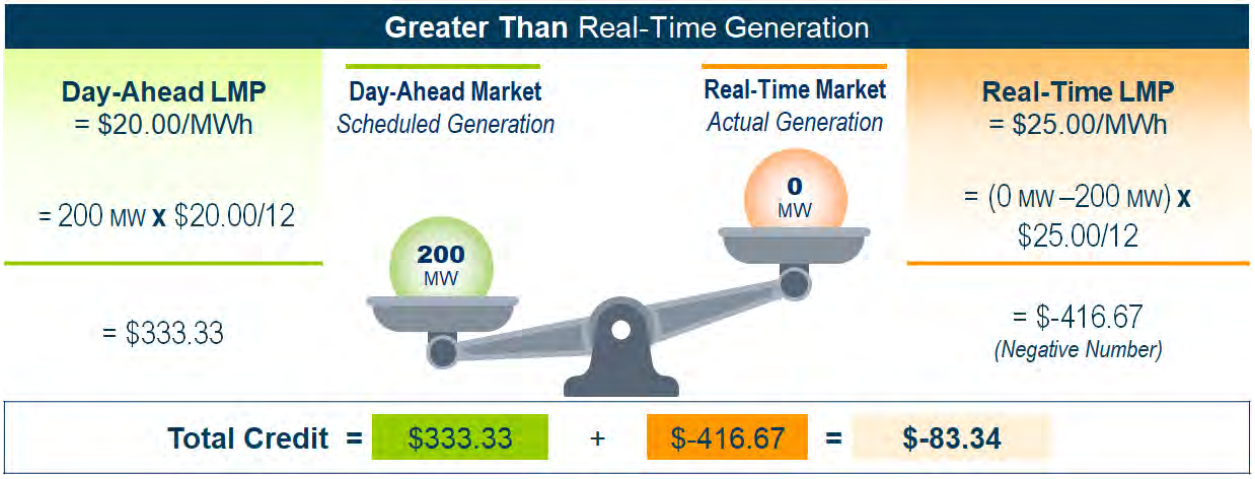
In Figure 72, the Generator submitted a 200 MW offer in the Day-Ahead Market. The Day-Ahead Market cleared at $20.00/MWh. The Day-Ahead Market settlement for the generator is the Day-Ahead Market scheduled generation multiplied by the Day-Ahead Market price, or 200 MW multiplied by $20.00 MW/h, divided by 12. The Day-Ahead Market credit for this generator is $333.33.

In real time, the Generator produced 200 MW. The balancing settlement is the difference between the Real-Time Market actual generation and the Day-Ahead Market scheduled generation. In this case, the generator was committed for 200 MW in Day-Ahead Market and produced 200 MW in real time. The generator is fully hedged (not exposed to real-time prices.) The balancing settlement is therefore $0.00.

The Total Credit for this generator for this five-minute interval is $333.33.

Figure 73 presents a settlement example for a generator that is committed in the Day-Ahead Market and trips during real time.

Figure 73. Day-Ahead Committed Generator That Trips in Real-Time Settlement Example



In Figure 73, the generator submitted a 200 MW offer in the Day-Ahead Market. The Day-Ahead Market cleared at $20.00/MWh. The Day-Ahead Market settlement for the generator is the Day-Ahead Market scheduled generation multiplied by the Day-Ahead Market price, or 200 MW multiplied by $20.00 MW/h divided by 12. The Day-Ahead Market credit for this generator is $333.33.

In real time, the generator tripped and therefore did not produce any energy. The balancing settlement is the difference between the Real-Time Market actual generation and the Day-Ahead Market scheduled generation. In this case, the generator was committed for 200 MW in the Day-Ahead Market but produced 0 MW in the Real-Time Market. The generator needs to buy back the megawatts committed in the Day-Ahead Market at the Real-Time LMP. The balancing settlement for this five-minute interval is the difference between the Real-Time Market actual generation and the Day-Ahead scheduled generation, multiplied by the Real-Time Market LMP (divided by 12). The balancing settlement for this five-minute interval is -$416.67.

The total credit for this generator for this five-minute interval is -$83.34.

Interchange

Figure 74 and Figure 75 provide hourly net interchange values between PJM and neighboring market areas NYISO and MISO along with interface price values for PJM and the neighboring market areas. Interface pricing enables Market Participants to the profitability of scheduling energy transfers between or through neighboring Balancing Authorities.

During periods where the system is stressed and internal supply is close to or inadequate to meet energy and reserve needs, interface prices are used to incentivize Market Participants in neighboring regions to sell available power to PJM to relieve emergency conditions. On Dec. 23 and Dec. 24, interchange flows were generally into PJM from NYISO, which is reflected in the interface prices. Conversely, interchange flows for both days were generally out of PJM to MISO and our southern non-market neighbors [Tennessee Valley Authority (TVA), Louisville Gas and Electric Company and Kentucky Utilities Company (LGE-KU), Duke Energy Progress East (DEP-East), and Duke Energy Progress West (DEP-W)]. In those cases, system conditions were more stressed in the neighboring areas.

Figure 74. NYISO Net Interchange

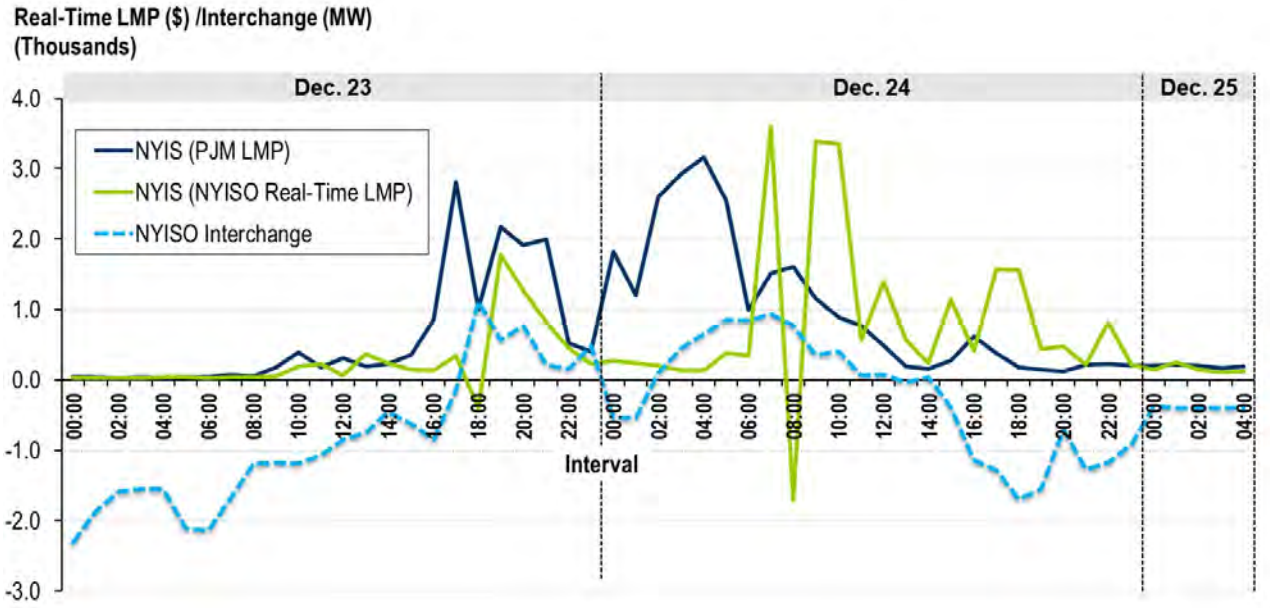


Figure 75. MISO Net Interchange

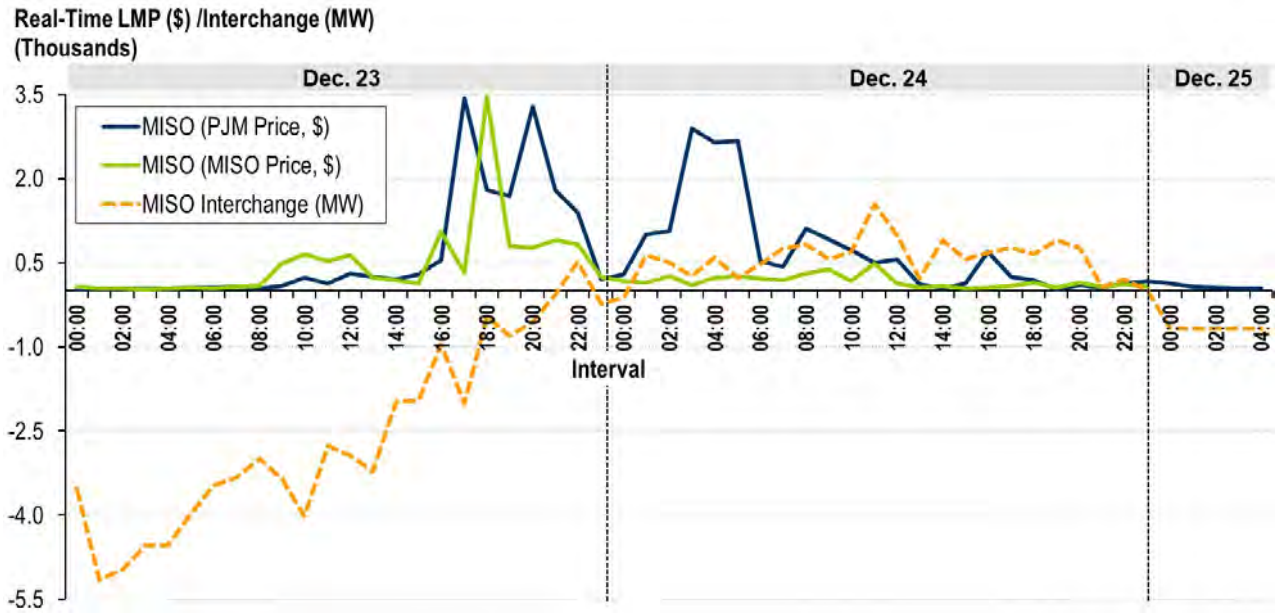


Figure 76 provides hourly net interchange values between PJM and the aggregate net interchange for LG&E-KU, TVA, Duke, DEP-East, and DEP-West, along with interface price values for PJM.

Figure 76. South Net Interchange

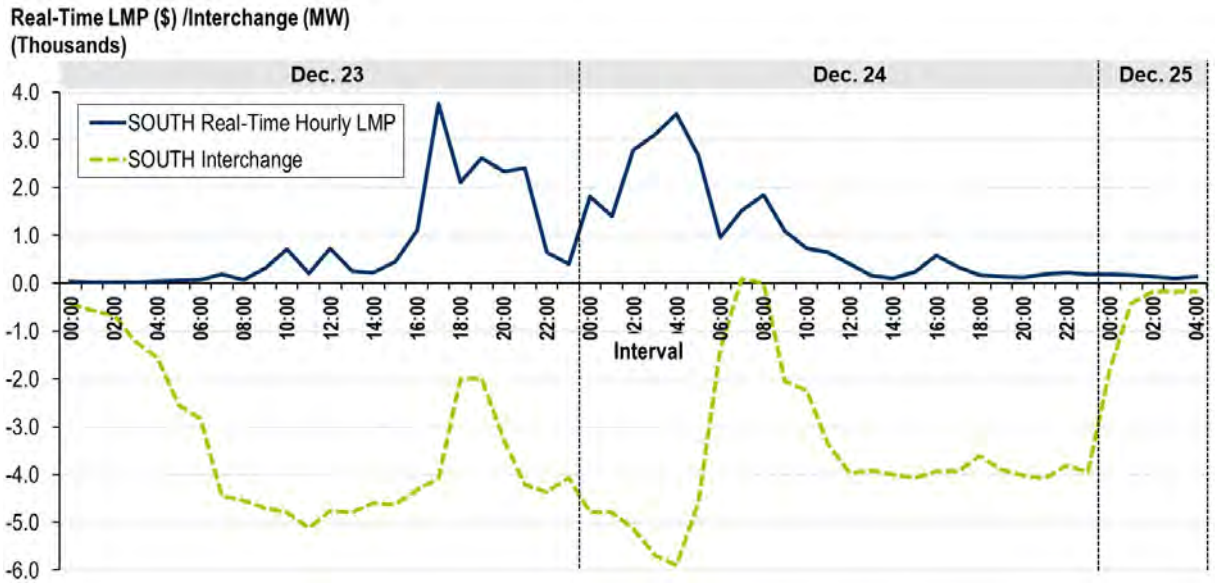
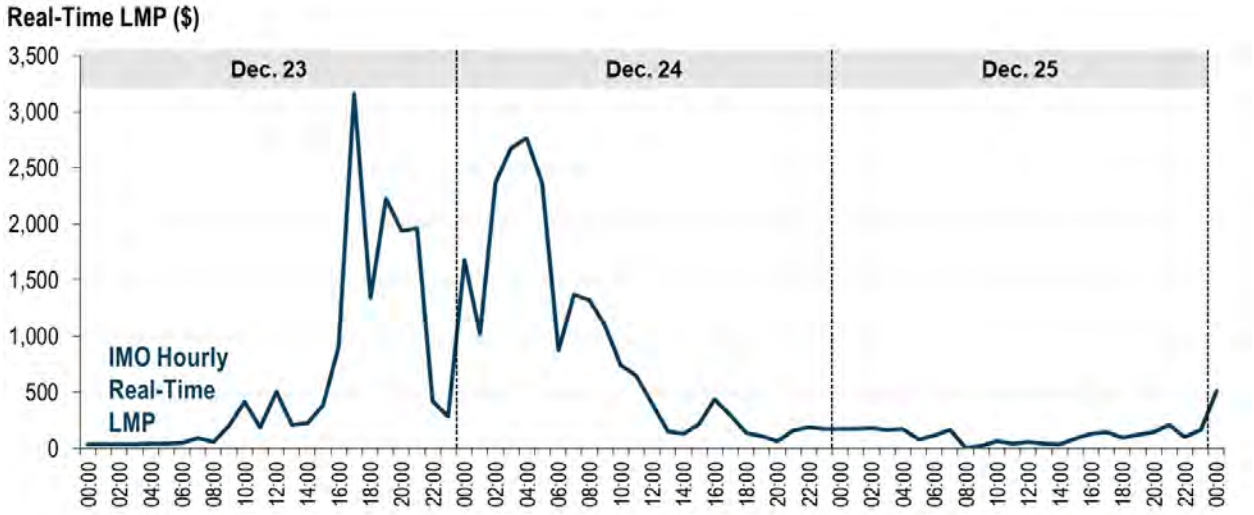


Figure 77 provides hourly pricing for the IMO interface. This information can be used by Market Participants during real time to make energy transfer decisions.

Figure 77. IMO Net Interchange



Ancillary Services: Regulation and Reserves

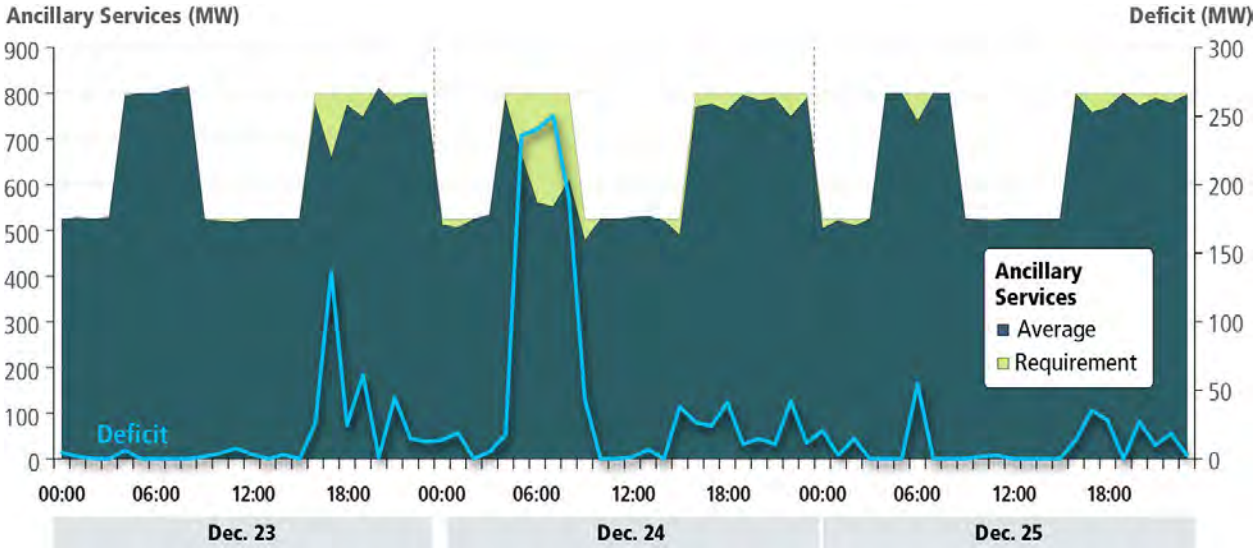
During Winter Storm Elliott, high prices for regulation, synchronized reserve, and Non-Synchronized Reserves occurred at the same time as high Real-Time Energy LMPs. During these stressed conditions, ancillary service prices increased as the reserve margin decreased, and system capacity competed to meet the ancillary services requirement while maintaining power balance.

Regulation Market Results

Regulation service corrects for short-term changes in electricity use that might affect the stability of the power system. It helps match generation and load and adjusts generation output to maintain the desired system frequency of 60 hertz. PJM's Regulation Market aligns compensation with actual performance for resources that provide regulation service. Resources are compensated for their accuracy, speed and precision of response in providing regulation service to the system.

On Dec. 23, as well as Dec. 24, PJM was deficit regulation, as presented in Figure 78, which presents the regulation megawatts, on average, by hour:

Figure 78. Regulation MW, on Average, by Hour

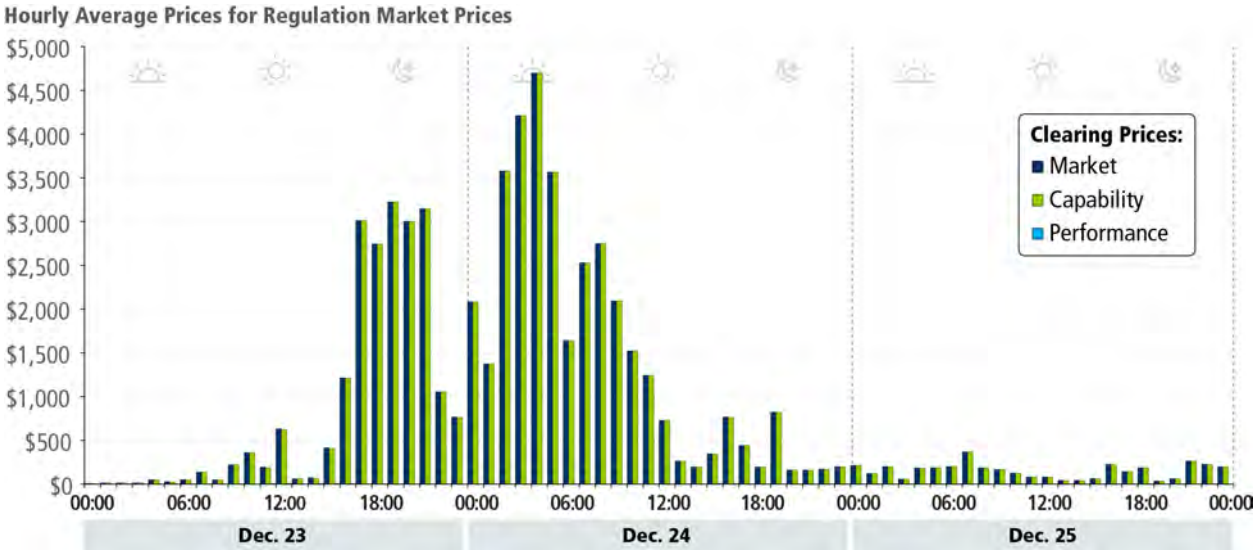


The regulation deficit is caused by the generator availability issues detailed in this report that resulted in a lack of available regulation-capable resources to commit. The regulation price spikes seen on Dec. 23 and Dec. 24 can be attributed to the low performance factor of the marginal unit for regulation as high-performing generators were being used for energy and reserves instead of regulation. High lost opportunity costs (LOC) were also a contributing factor to the high regulation prices. Recall that LOC is intended to capture foregone energy revenues from providing a service other than energy. When those foregone energy revenues are high because energy prices are high, regulation LOC and regulation prices can also be high to ensure resources are incentivized to provide needed regulation and not energy.

Unlike reserves, regulation is not co-optimized with energy in real-time. Similarly, there is also no explicit mechanism for shortage pricing of regulation as there is for reserves. As stated, regulation prices rose and fell roughly in correlation with energy prices during the evening of Dec. 23 and morning of Dec. 24 because of the calculation of regulation lost opportunity costs based on the high LMPs during these periods, not because of the regulation shortages.

Figure 79 presents the hourly average prices for RMCP for Dec. 23, 24 and 25.

Figure 79. Dec. 23, 24 and 25 Hourly Average Prices for RMCP



For more information on how the Regulation Market prices are calculated, please reference Manual 11, Section 3.

Reserve Market Price Trends

Reserves represent the generating capability that is "standing by," ready for service in the event that something happens on the power system, such as the loss of a large generator. The severity of the event determines how quickly the reserves have to be picked up.

In Oct. 2022, PJM implemented Reserve Price formation, resulting in the following changes:

- Consolidation of Tier 1 and Tier 2 Synchronized Reserve products
- Alignment of reserve products in day-ahead and real-time to ensure that the reserves needed for real-time operation are recognized on a forward basis during the scheduling processes for the next operating day
- Flexible modeling of reserve subzones

Figure 80 presents the market clearing prices (MCPs) for Synchronized Reserve (SRMCP), Non-Synchronized Reserve (NSMCP), and Secondary Reserve Market Clearing Price (SecRMCP) for Oct. 2022 through Dec. 2022. Notwithstanding Dec. 2022, the SRMCP, NSRMCP and SecRMCP prices have been at or near $0.00/MWh since the Oct. 2022 implementation of the Reserve Price Formation changes.

Figure 80. SRMCPs, NSMCPs and SecRMCPs

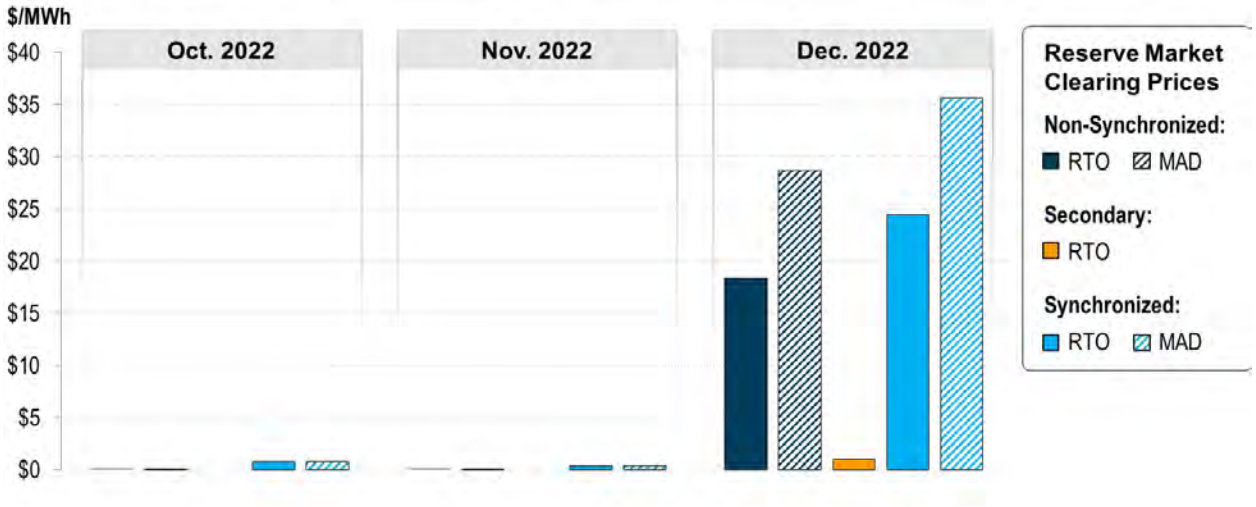


Figure 81 presents daily max and daily average SRMCPs since Oct. 1, 2022. This figure shows that the drivers of the high monthly averages SRMCPs observed in Dec. 2022 and displayed in Figure 80 are driven almost entirely by the operational events and market outcomes related to Winter Storm Elliott.

Figure 81. Shortage Pricing Impacts on SRMCP

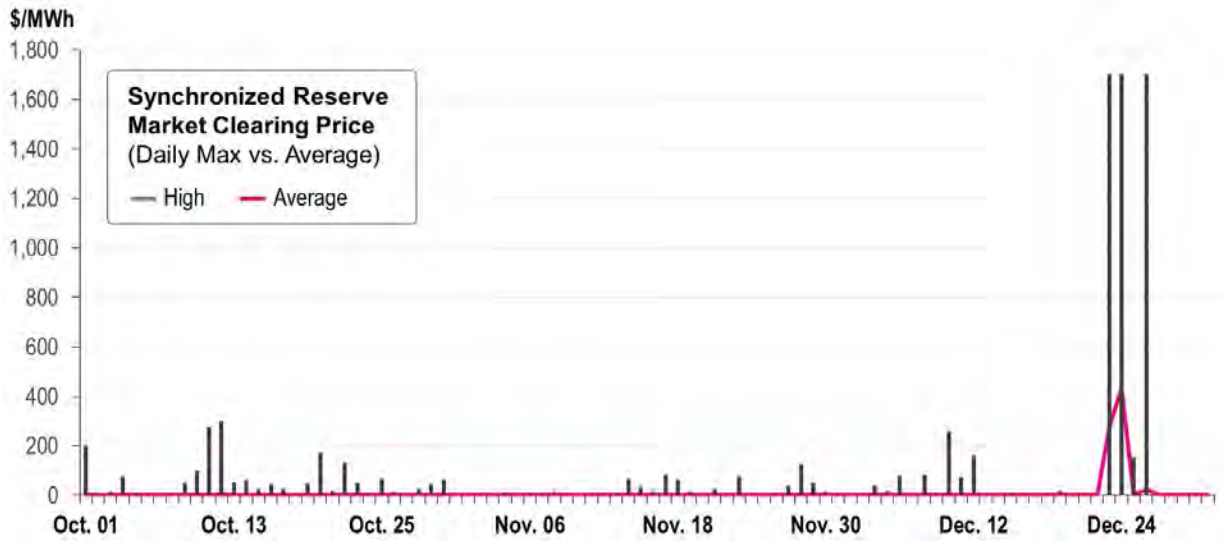
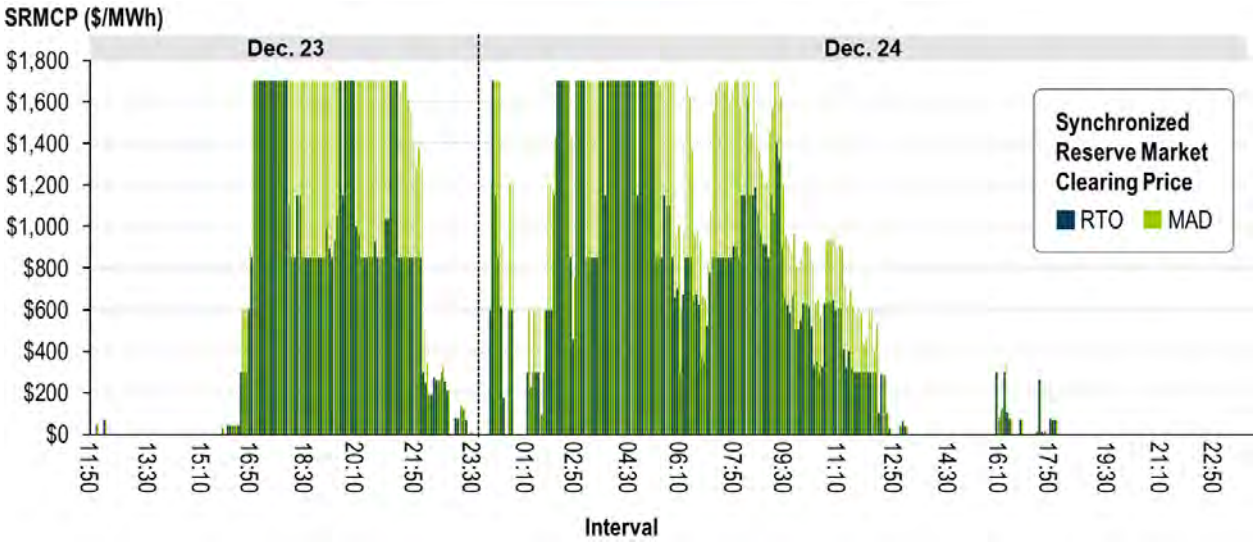


Figure 82 presents the Real-Time SRMCPs for Dec. 23 and Dec. 24.

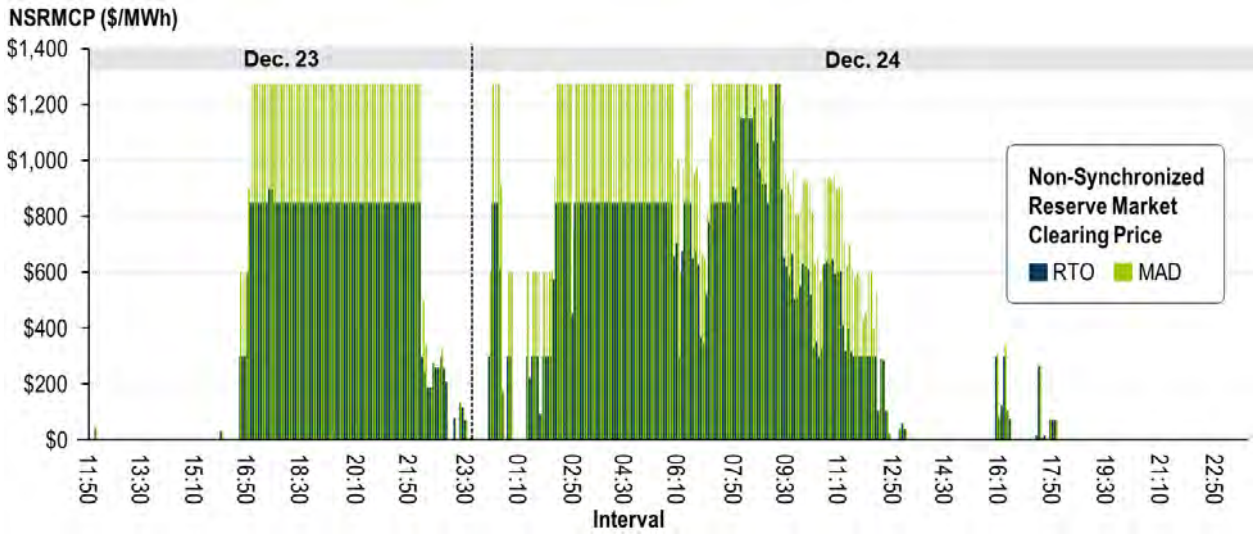
Figure 82. Dec. 23 and 24 Real-Time SRMCPs



The SRMCPs in many intervals are either at a level of $850/MWh or $1,700/MWh depending on the reserve product that was short and the location it was short. The price level of $1,700/MWh represents the price cap that exists for this product.

Figure 83 presents the Real-Time NSRMCPs for Dec. 23 and Dec. 24.

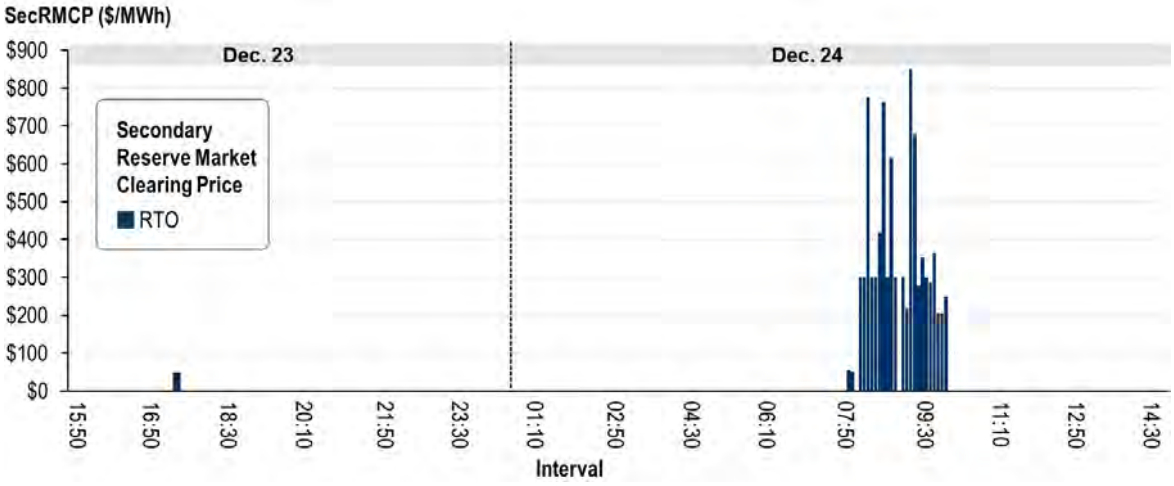
Figure 83. Dec. 23 and Dec. 24 Real-Time NSRMCPs



The Non-Synchronized Reserve Market Clearing Price (NSRMCP) is the clearing price paid to offline resources that can start within 10-minutes and be used to satisfy the Primary Reserve and 30-minute requirements. Market Sellers offer prices for the Non-Synchronized Reserve and Secondary Reserve products are $0.00/MWh; however, a Non-Synchronized Reserves LOC is estimated by the PJM market clearing engines. This LOC represents the foregone revenue an eligible offline resource could have received if had operated, given the forecasted LMP produced by the IT SCED engine. The current price cap Non-Synchronized Reserve is 1.5 times the Reserve Penalty Factor of $850/MWh, or $1,275/MWh.

Figure 84 presents the Real-Time SecRMCPs for Dec. 23 and Dec. 24.

Figure 84. Dec. 23 and Dec. 24 Real-Time SecRMCPs



The SecRMCP was $0.00/MWh of most of the Winter Storm Elliot event except for approximately two hours on Dec. 24. During that period, the SecRMCP reached its price cap of $850/MWh for one interval.

Given the observed issues with reserve performance and availability during Winter Storm Elliott and other inefficiencies PJM believes exist in the design of these markets, PJM believes there is a need to evaluate various aspects of its reserve market design including the products, offer structure, levels procured, performance incentives, and deployment practices to ensure the necessary amount of reserves is being procured, priced by the market and incentivized to perform at a high level. PJM plans to bring a Problem Statement and Issue Charge to Stakeholders to address these items in the near future.

Synchronized Reserve Events and Reserve Performance

As described earlier, Synchronized Reserves are reserve generators that are already synchronized to the grid and can be loaded within 10 minutes. PJM carries enough Synchronized Reserves to cover the unexpected loss of the largest single generation contingency operating on the PJM system at that time, plus a small margin. Typically, this reserve requirement is approximately 1,600 MW.

The conditions of Winter Storm Elliott led to PJM requesting the loading of Synchronized Reserve generation on five separate occasions during the two-day period of Dec. 23 and Dec. 24. Four of these events were called in response to a low ACE caused by increasing load combined with generation tripping and start failures. One of the events was called in direct response to the loss of a unit.

Five Synchronized Reserve Events over a two-day period is very unusual. Note that the average duration between Synchronized Reserve Events in 2021 was 22 days. All five of the events during Winter Storm Elliott exceeded 10 minutes in duration. Two of the events exceeded one hour in duration at 1 hour 51 minutes and 1 hour 27 minutes. The average duration for these five events was 53 minutes and 17 seconds. The average duration of the other 18 Synchronized Reserve Events that occurred in 2022 was 9 minutes and 57 seconds.

System conditions and ACE control prevented the PJM system operators from ending these Synchronized Reserve Events earlier, as all available reserve megawatts were required to support the ACE and provide overall system control. Table 7 provides details of these five events.

Table 7. Five Synchronized Reserve Events

Event Date	Start (EST)	End (EST)	Duration	Zone	Reason	PAI in effect
Dec. 23	10:14	10:25	00:11:07	RTO	Low ACE	No
	16:17	18:09	01:51:29			Yes (17:30–18:09)
Dec. 24	00:05	00:30	00:25:43			No
	02:23	02:54	00:30:35		Unit Trip	No
	04:23	05:51	01:27:32		Low ACE	Yes (04:25–01:27)

PJM measures the response of resources with a Real-Time Synchronized Reserves commitment as detailed in PJM Manual 11, Section 4.5. Note, Day-Ahead Synchronized Reserve commitments are reevaluated in real time, and only those resources that have a real-time commitment are obligated to respond.

For each Synchronized Reserve Event, the magnitude of each resource's response is the difference between the resources' output at the start of the event and its output 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, resource output at the start of the event is defined as the lowest telemetered output between one minute prior to and one minute following the start of the event. Similarly, a resource's output 10 minutes after the event is defined as the greatest output achieved between nine and 11 minutes after the start of the event.

Also relevant for the events lasting longer than 10 minutes, all resources must maintain an output level greater than or equal to that which was achieved as of 10 minutes after the event for the duration of the event or 30 minutes from the start of the event, whichever is shorter. The response actually credited to a given resource will be reduced by the amount the megawatt output of that resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. There is no current performance evaluation for events lasting longer than 30 minutes, beyond the initial 30-minute period.

Although not relevant for these events, in cases where an event lasts less than 10 minutes, resources are credited with the amount of reserve capacity they are assigned.

Since PJM's implementation of the Reserve Price Formation changes on Oct. 1, 2022, the entirety of the Synchronized Reserve Requirement is assigned to specific resources in a co-optimization with energy. Resources assigned these reserves each Real-Time interval have an obligation to perform or face a penalty in the amount of non-performance. This penalty consists of two components as follows:

1 | The resource is credited for Synchronized Reserve for the amount that actually responded for all intervals in which the resource had an assignment (either self-scheduled or assigned) on the day the event occurred.

2 | An obligation to refund at the Synchronized Reserve Market Clearing Price the amount of the shortfall for all Real-Time Settlement Intervals that the resource had an assignment for a period of the lesser of a) the average number of days between events or b) the number of days since the resources last non-performance.

Synchronized Reserve response to the five events during Winter Storm Elliott for resources assigned reserves was generally poor.

- The highest response was 86.4% of assignment, as seen during the Dec. 23, 10:14 event, which was the first Synchronized Reserve deployment during Winter Storm Elliott. Not coincidentally, this was also the shortest of the five events at 11:07 minutes.

- The lowest response was 16.8% of assignment, as seen during the Dec. 24, 04:23 event.
- The average response of these five events was 47.8%.
- The average response of assigned Synchronized Reserve since the implementation of the Reserve Price Formation changes on Oct. 1, 2022, excluding these Winter Storm Elliott events, is 49.8%.

Details of the reserve performance for resources assigned Synchronized Reserve can be found in Table 8.

Table 8. Assigned Reserve Performance

			Synch Reserve (MW)			
Event Date	Start (EST)	End (EST)	Assignment	Response (Units with assignment)	Shortfall to Assignment (MW)	Response to Assignment (%)
Dec. 23	10:14	10:25	1,791	1,547	244	86.4%
	16:17	18:09	1,846	945	901	51.2%
Dec. 24	00:05	00:30	1,767	930	837	52.6%
	02:23	02:54	1,665	535	1,130	32.1%
	04:23	05:51	1,007	169	838	16.8%

PJM has observed a drop in performance of approximately 20% for resources assigned Synchronized Reserve (excluding Winter Storm Elliott events) since the implementation of Reserve Price Formation on Oct. 1, 2022. Unrelated to the Winter Storm Elliott response, PJM has taken the following actions to address this drop in performance:

- Continued monitoring of Synchronized Reserve Performance and ACE recovery performance
- Identification of data trends including non-performance by specific resource, resource type and resource owner
- Reach out to resource owners with poor performance to identify causes of this poor performance

In addition to Synchronized Reserve response from resources assigned reserve, PJM typically observes significant response from resources that were not specifically assigned reserve at the time of the Synchronized Reserve event. While the All-Call message that announces a Synchronized Reserve Event requests all resources to load any Synchronized Reserve that they have available, resources without a Synchronized Reserve assignment at the start of the event are under no financial obligation to respond to these events and are not subject to nonresponse penalties for Synchronized Reserves. Since the implementation of Reserve Price Formation on Oct. 10, 2022, unassigned resources no longer receive a Tier 1 bonus for reserves provided.

There was also an over-response from some resources that exceeded their Synchronized Reserve assignment, although this was fairly minimal.

In the Dec. 24, 02:23 event, even with the additional contributions of reserves above assignment and from resources not assigned reserve, the total response still fell short of the system assigned reserve requirement. The response in megawatts from both units with and without Synchronized Reserve assignments are shown below in Table 9.

Table 9. Unit Synchronized Reserve Assignments Unit Synchronized Reserve Assignments Unit Synchronized MW Response With and Without Assignments

				Synch Reserve Unit Response (MW)			
Event Date			Synch Reserve Assignment (MW)	With Assignment	Above Assignment	Without Assignment	Total
Dec. 23	10:14	10:25	1,791	1,547	671	2,447	4,665
	16:17	18:09	1,846	945	161	2,512	3,618
Dec. 24	00:05	00:30	1,767	930	79	1,333	2,342
	02:23	02:54	1,665	535	78	1,006	1,619
	04:23	05:51	1,007	169	7	976	1,152

As described earlier, resources that provide less Synchronized Reserve than their assignment during a Synchronized Reserve Event are required to refund Synchronized Reserve revenue in the amount of the shortfall for the durations specified above. Since the penalties are based on the SRMCP, these penalties were higher than average due to the high SRMCPs during this time. The total retroactive penalties for these five events are listed in Table 10 below.

Table 10. Total Retroactive Penalties for Five Events Dec. 23–24

Event Date	Start (EST)	End (EST)	Synch Reserve Retroactive Penalty $
Dec. 23	10:14	10:25	$8,331.65
	16:17	18:09	$55,156.22
Dec. 24	00:05	00:30	$866,580.05
	02:23	02:54	$384,402.02
	04:23	05:51	$437,698.69

PJM has identified an opportunity for PJM, in conjunction with stakeholders, to evaluate Synchronized Reserve commitment and performance. There is also an identified opportunity to discuss alignment of market incentives with operational decisions. Following the PJM stakeholder process as described in PJM Manual 34, Section 6, PJM staff will bring a Problem Statement and Issue Charge forward to begin engagement with stakeholders on these opportunities.

Cost Offer Verification

As directed by FERC Order 831, effective April 12, 2018, PJM implemented a verification process for cost-based Incremental Energy Offers above $1,000/MWh. A resource's Incremental Energy Offer must be capped at $1,000/MWh or the resource's cost-based Incremental Energy Offer, whichever is higher. Cost-based Incremental Energy Offers are capped at $2,000/MWh for the purpose of calculating LMPs. The costs underlying a cost-based Incremental Energy Offer above $1,000/MWh must be verified before it can be used to calculate LMPs.

If a resource submits an Incremental Energy Offer above $1,000/MWh, and the underlying costs cannot be verified before the market clearing process begins, the offer may not be used to calculate LMPs. In this case, the resource may be eligible for a make-whole payment if it is dispatched and its costs are verified after the fact. Likewise, a resource may also be eligible for a make-whole payment if it is dispatched and its verified cost-based Incremental Energy Offer exceeds $2,000/MWh. All resources, regardless of type, are eligible to submit cost-based Incremental Energy Offers in excess of $1,000/MWh.

PJM uses a screening process to verify the reasonableness of each generation resource's cost-based Incremental Energy Offer segment in excess of $1,000/MWh before it is considered eligible to be used in dispatch or the calculation of LMPs. This screening process is applicable to all generation resources, including those that are Fast-Start capable. Fast-Start capable resources are subjected to an additional screening process.

- Day-Ahead Market Incremental Energy Offers between $1,000/MWh and $2,000/MWh must be submitted prior to the close of the Day-Ahead Market bid period to be screened for eligibility to set LMP in the Day-Ahead Market.
- In the Real-Time Market, a resource's cost-based offer must be submitted at least 65 minutes prior to the start of the operating hour in order for the Incremental Energy Offer segments between $1,000/MWh and $2,000/MWh to be screened for eligibility to set LMP.

PJM uses published index settle prices for the commodity price and cost inputs provided by the Market Seller in the Cost Offer Assumptions (COA) module within the Member Information Reporting Application (MIRA) to calculate the Maximum Allowable Incremental Cost as outlined in the PJM Operating Agreement. Submission to COA, or other system(s) made available is considered submission to PJM and the MMU.

The Market Seller is required to provide heat inputs and performance factors in COA, or other system(s) made available for submission of such data. The heat inputs and performance factors should be provided at least one week prior to the operating day. For each Incremental Energy Offer segment greater than $1,000/MWh, PJM evaluates whether such offer segment exceeds the reasonably expected costs for that generation resource by determining the Maximum Allowable Incremental Cost for each segment in accordance with Section 6.4.3 of Schedule 1 of the PJM Operating Agreement.

- If the cost submitted for the offer segment is less than or equal to the Maximum Allowable Incremental Cost value, then that segment is deemed verified and is eligible to be used in dispatch and to set LMP.
- If the cost submitted for the offer segment is greater than the Maximum Allowable Incremental Cost value, then the cost-based offer for that segment and all segments at an equal or greater price are deemed not verified. Such segments are capped at the greater of $1,000/MWh or the price on the most expensive verified segment for the purposes of dispatch and setting LMP.

PJM notifies the Market Seller of the verification status of each segment upon completion of the screen. The Generation Resource Exception Process is presented in PJM Manual 11, Section 2.3.6.2. The process is triggered infrequently, and PJM is evaluating if there are opportunities to provide additional training on the process.

Table 11 illustrates the number of energy offers in excess of $1,000/MWh received by PJM during Winter Storm Elliott:

Table 11. Energy Offers in Excess of $1,000/MWh

	Number of units with:		
Market Day	Offers above $1,000/day	Schedule ID with offers above $1,000/Day	Exception request approved
Dec. 23	*	*	*
Dec. 24	12	16	12
Dec. 25	49	93	40
Dec. 26	19	28	17

** Due to PJM confidentiality rules, PJM is unable to disclose the counts for Dec. 23.*

All offers above $1,000/MWh received during Winter Storm Elliott were processed in advance of the Real-Time Market and were able to set LMP in real time. Some units with energy offers in excess of $1,000/MWh did set LMP with these offers.

Uplift

To incent generators and Demand Resources to operate as requested by PJM, resources that are scheduled by PJM and follow PJM dispatch instructions are guaranteed to fully recover their costs of operation. Uplift cost is created when market revenues are insufficient to cover the costs of the resources following PJM's direction.

Operating Reserve costs are payments made to economic Demand Resources and generation resources that follow PJM's direction to cover their costs and are the primary form of uplift in PJM. These payments are outside of the market and are not included in the pricing signals that are visible and transparent to Market Participants.

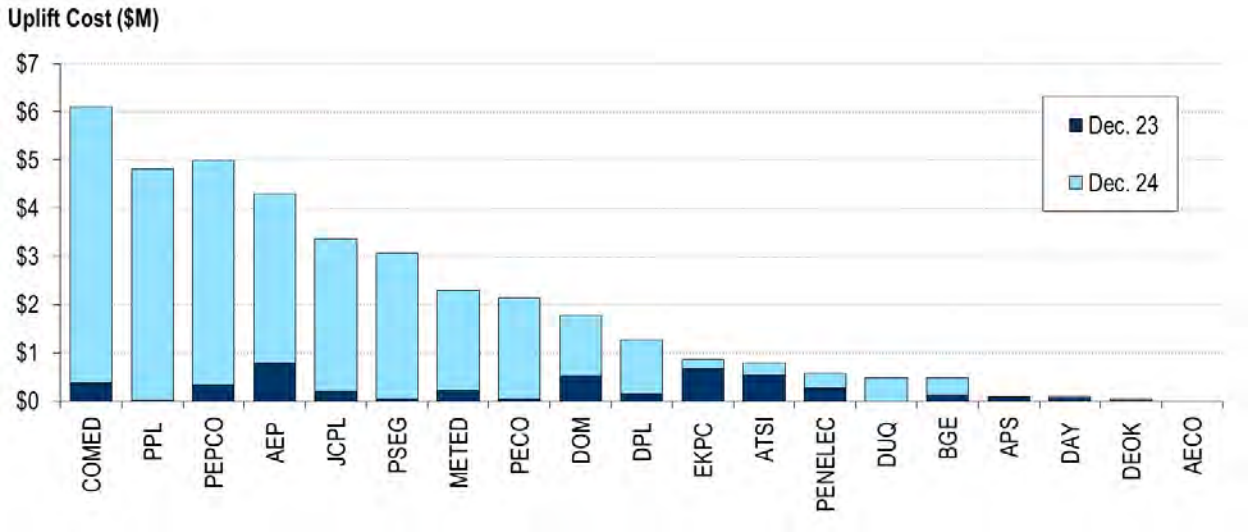
There are two reasons for out-of-market costs:

1 | Units that are running uneconomically at the direction of PJM are made whole to their offers.

2 | Units that are committed in the Day-Ahead Market and did not run in real time at PJM's direction, or had price spikes higher in real time when compared to the day-ahead lost opportunity cost, are made whole to their offers.

The Figure 85 shows the total uplift incurred by zone for Dec. 23 and Dec. 24.

Figure 85. Dec. 23 and Dec. 24 Total Uplift Incurred by Zone



A majority of the uplift cost on Dec. 23 and Dec. 24, as shown Figure 85, was due to generators scheduled by PJM running in real time to meet reliability needs.

Factors that contributed to uplift from this event include:

- Natural Gas Prices – High natural gas prices exacerbated the cost of uplift as the units operating at PJM's direction were more expensive than under more typical conditions.
- Contractual Constraints – Due to restrictions on natural gas deliveries, many resources required PJM to maintain strict megawatt output levels during periods when they were uneconomic to ensure they were

available during peak conditions. Additionally, the lack of alignment between the gas and electric day timing often required PJM to commit to running gas units prior to the Day-Ahead Energy Market.

- Prudent Operations – During Winter Storm Elliott, PJM committed resources for expected extreme system conditions. Such operations are typical during Cold Weather Alerts, resulting in the scheduling of additional reserves to account for increased forced outage rates as identified in the PJM Emergency Operations Manual. Scheduling resources in anticipation of extreme weather conditions and above-average forced outages can lower LMPs resulting in higher uplift levels.
- Interchange Volatility – Variable imports and exports of energy, which reacted to PJM energy prices, affected locational marginal prices and commitment decisions by PJM. The amount of power imported is difficult for PJM to forecast and is not completely under PJM's control; therefore, PJM must schedule internal resources to ensure that adequate generation is available given interchange uncertainty.

In the PJM market design, if a generation resource follows PJM's commitment and dispatch instructions, that generator is able to fully recover its costs for the hours it runs at PJM's direction. Operating Reserve payments are designed to incent resource owners to follow PJM direction to help maintain control of the grid in the most efficient manner possible, and also to ensure adequate operating supply plus additional capability for reserves. Day-ahead and real-time Operating Reserve credits are paid to resource owners; these credits are paid by Market Participants as Operating Reserve charges.

Increased Operating reserve costs are a side effect of running additional generation to support outages or other situations on the grid such as operational uncertainty. Uplift costs can be high when the primary fuel of additional generation being run is also high. During Winter Storm Elliott, generation was needed specifically in the northeastern region of PJM, where there is a large amount of natural gas-fired generation. Operating Reserve payments increased when the additional generation was run. Due to the tight supplies in the natural gas market, many PJM generators were kept online to mitigate the risk of being unable to obtain natural gas after shutting down. Some of these generators were run overnight because they could not shut down and restart again due to fuel or weather issues.

Market Settlement Statistics

The Day-Ahead Market allows participants to purchase and sell energy and reserves at binding day-ahead prices. Generators that are committed in the Day-Ahead Market are paid for energy based on the Day-Ahead LMP. LSEs that clear a demand bid the pay for energy based on the Day-Ahead LMP. Any quantity deviations from quantities cleared in the Day-Ahead Market are settled at the Real-Time LMP in a balancing settlement.

Units that are not committed in the Day-Ahead Market but are committed in the RAC or real-time are paid the Real-Time LMP. In the case of Dec. 23 and 24, Real-Time LMPs reached levels that were substantially higher than those in Day-Ahead. This is because the Real-Time Market is used to balance supply and demand in real time, and there is often more uncertainty about the amount of electricity that will be needed in real time. Phenomenon such as interchange volatility, load forecast uncertainty and generator trips only occur in real-time and therefore only directly influence those prices.

By understanding how balancing settlements work, generators can better manage their risks and ensure that they are adequately compensated for their output. Table 12 presents the divergence between Day-Ahead and Real-Time market prices. While this table is presented from a supply perspective, the fundamentals of the settlement apply to loads as well. That is to say that only those loads that are consuming more in real-time than they procured in the Day-Ahead Market are exposed to the high Real-Time LMPs on Dec. 23 and 24. Typically this is less than 5% of total load.

Table 12. Day-Ahead and Real-Time Market LMPs

	Day-Ahead Market		Peak LMP		Reliability Assessment Commitments (RAC) and Real-Time Commitments
	Loaded Generation (RTO Gen MW Figure 9)	Committed Generation with Outages	Day-Ahead	Real-Time	
Dec. 23	133,165 MW	12,847 MW	$224	$3,707	3,168 MW
Dec. 24	134,615 MW	16,560 MW	$259	$3,664	6,000 MW

The weekly gross billing statistics represent the total charges included in the weekly month-to-date invoices (generally spot market energy, congestion, losses and capacity charges).[11] Spot market energy, transmission congestion and transmission loss charges include positive and negative charges for supply and demand-side billing in a single charge billing line item, rather than separate charge and credit line items, as is the case with most other line items. To account for this difference, only the positive charges billed through these line items are included in the gross billing metric.

PJM's weekly invoices bill activity from the first day of the month through the end of the weekly billing period. The weekly gross billing values are calculated as the difference between the total month-to-date bill for a given week and the month-to-date bill for the prior week. For weeks with fewer than seven days, of which there was one, the gross billing was normalized to represent a seven-day week. Figure 86 presents the weekly gross billings statistics for the few weeks before and after Winter Storm Elliott.

Figure 86. Weekly Gross Billing Statistics

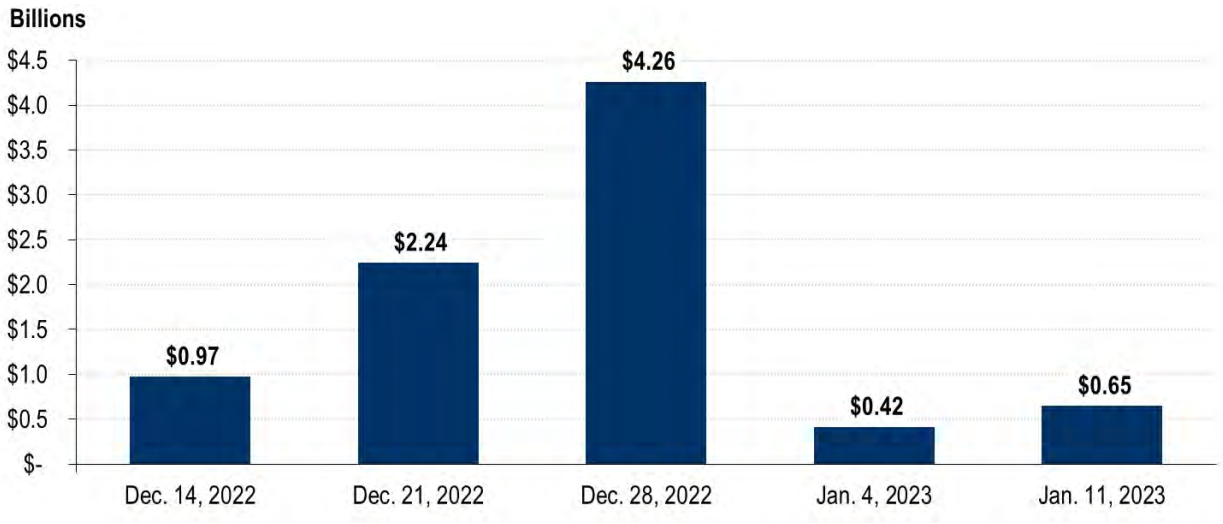
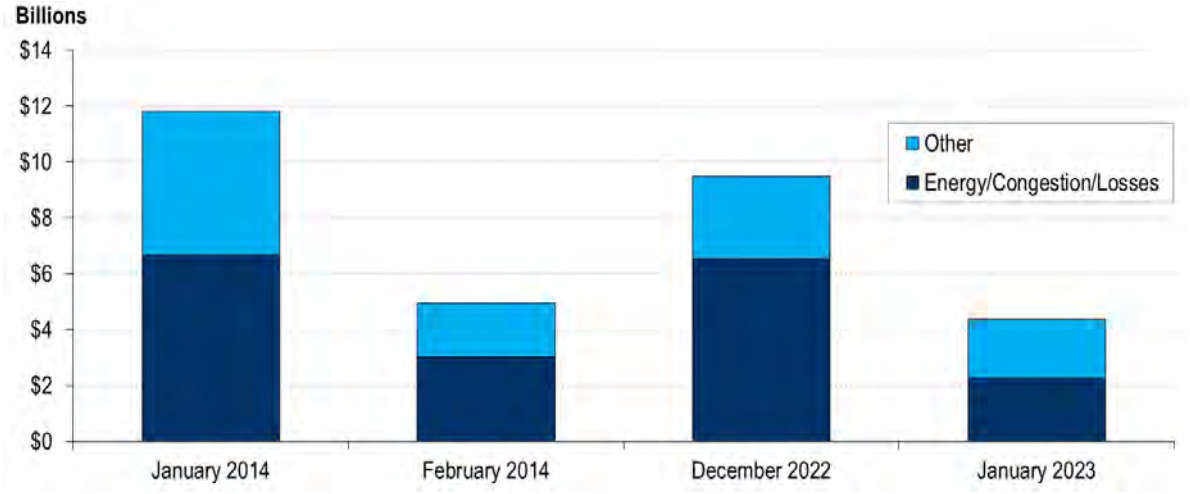


Figure 37 displays gross billing for Dec. 23 and Dec. 24, embedded in the bar chart for the week of Dec. 28. A significant increase in gross billing is observed when comparing the prior two weeks and successive two weeks to the week of Dec. 28. System conditions and operator actions reflecting the status of the RTO resulted in the higher gross billing. A contributing factor can be found in the average temperature for Dec. 23, which was 9.3 degrees Fahrenheit, with an average temperature on Dec. 24 of 7.6 degrees Fahrenheit.

Figure 87 presents the monthly gross billing comparison of Winter Storm Elliott to the 2014 Polar Vortex.

[11] PJM Manual 29, Section 3.2 details the charge line items included in the weekly invoices.

Figure 87. Winter Storm Elliott Monthly Billing vs. 2014 Polar Vortex Monthly Billing



In Figure 87, "Other" includes all billing except for spot market energy, congestion and transmission loss billing, including Schedule 9 and 10 charges, uplift, capacity and FTRs. As observed in the bar chart, gross monthly billing for the 2014 Polar Vortex exceeded gross monthly billing stemming from Winter Storm Elliott. A contributing factor for this difference ties to average temperatures. Average temperature for the month of January 2014 was 24.2 degrees Fahrenheit, with an average temperature of 35.4 degrees Fahrenheit for the month on December 2022.

Performance Assessment Intervals

Note: All data in this section is reflective of the performance assessment information used in the May 2023 billing statement and is being presented for informational purposes only. Nothing in this section may be construed to provide any settled expectations of charges or bonus payments. As such, to the extent adjustments are made subsequent to the May 2023 billing statement, the values herein may differ from those observed on market participants' settlement reports.

Background

The Maximum Emergency Generation Actions issued on Dec. 23 and Dec. 24, 2022, triggered Performance Assessment Intervals (PAIs) that require PJM to evaluate the performance of all resources located in the Emergency Action area for each applicable five-minute interval. The Emergency Action area for the Winter Storm Elliott performance assessment event covered the entire RTO for the intervals designated in Table 13. In total, there were 277 intervals for which performance was assessed. Given the significant number of intervals, most performance assessment data will be presented on an hourly basis (typically an average of the five-minute interval values in the hour) for purposes of this report. Other data will be looked at across the aggregate PAIs, from 17:30 EPT on Dec. 23 to 22:00 EPT on Dec. 24, or across the aggregate PAIs within a day.

Table 13. Impacted Zones for the Performance Assessment Events on Dec. 23 and Dec. 24

Location	Performance Assessment Intervals			Number of Intervals
Entire RTO	Dec. 23 17:30–23:00			66
	Dec. 24 04:25–22:00			211
		Total		277

The resources located in the RTO that were evaluated for this performance assessment event include:

- Generation: All generation resources, inclusive of Capacity Performance (CP) resources, energy-only resources and regulation-only resources
- Demand Response:
  - For Dec. 23, all pre-emergency and emergency DR (also referred to as Load Management) with 30-minute or 60-minute lead times dispatched by PJM
  - For Dec. 24, all pre-emergency and emergency DR dispatched by PJM (this includes all 30-minute, 60-minute and 120-minute lead times)
  - For both dates, some economic DR that was also dispatched or cleared in the energy and ancillary services markets
- Energy Efficiency: All annual Energy Efficiency resources
- Price-Responsive Demand: All price-responsive Demand Resources with a strike price that equaled or was lower than the five-minute LMP at their location

Based on the resource's performance and capacity commitment, resources may be assessed Non-Performance Charges or be eligible for bonus performance credits. Non-performance is determined based on the response of resources to fulfill their capacity commitments during each five-minute PAI, and no netting is permitted across intervals. Any performance shortfall or excess is calculated separately for each resource and each interval. Resources with a shortfall, or delivered energy (or reduction) less than expected based on the capacity commitment, are assessed a financial penalty. Resources demonstrating excess performance, or delivery of energy (or reduction) greater than expected based on the capacity commitment, are eligible for bonus payments.

PJM fielded many questions from Market Participants throughout and following the PAI event relating to the details of PAI business rules, penalty and bonus calculations, and Market Seller expectations during Winter Storm Elliott. This indicated the lack of widespread, detailed knowledge around the PAI process, likely due to the infrequent nature of performance assessments. It also reinforced the need to provide transparency into the PAI settlement process.[12]

PJM previously identified the following existing business rules, among others, that would benefit from more transparency, clarification or additional detail:

- Identification of assessed resources
- Calculation of real-time reserve and regulation assignment
- Calculation of scheduled megawatts for non-performance and bonus determinations

The effort to provide more transparency into the PAI settlement process started at the Market Implementation Committee and was eventually incorporated into the Resource Adequacy Senior Task Force scope. The recent requests for more

[12] Transparency Into PAI Settlements, PJM Issue Tracking, PJM.com

information into the process following Winter Storm Elliott underscore the need for this work to be addressed in the Critical Issue Fast Path – Resource Adequacy discussions.[13]

Balancing Ratio

For each PAI, PJM calculates a balancing ratio that represents the percentage share of total generation capacity commitments needed to support the load and reserves on the system within the Emergency Action area during that interval. This balancing ratio is then used to set the expected performance level of generation CP resources within the Emergency Action area for each PAI.

The balancing ratio is calculated as:

Balancing Ratio (BR) = (Total Actual Generation and Storage Performance + Net Energy Imports + DR Bonus Performance + PRD Bonus Performance) / All Generation and Storage Committed Unforced Capacity (UCAP) Commitments

Where:

- **Total actual generation and storage performance** is the actual metered output of the resources from PowerMeter, adjusted for any real-time regulation or reserves assignment.
- **Net energy imports** are the net energy import quantity during the event reported in ExSchedule, calculated as imports minus exports. This value is set to 0 for any intervals where exports exceeded imports.
- **DR bonus performance** is the net bonus megawatts for over-performing curtailment service providers (CSPs).
- **PRD bonus performance** is the net bonus megawatts for over-performing PRD resources.
- All **generation and storage-committed UCAP** are the sum of the CP commitment UCAP value for all Reliability Pricing Model (RPM) generation resources included in the assessment.

The balancing ratio is expected to align with the system demands during the Emergency Action period. The peak demand was 135,000 MW on Dec. 23 and 130,000 MW on Dec. 24. While these are high loads for the month of December, they are lower than the PJM peak load forecast that is used to establish the RPM reliability requirement (~163,000 MW). The RPM reliability requirement is established as the amount of capacity resources that are required to serve the forecast peak load and installed reserve margin to satisfy the PJM reliability criteria. As a result, it was expected that the balancing ratio would be less than 100%, because the demand during the PAIs was below the total committed capacity for those intervals. The average balancing ratio over the entire performance assessment event was 82.1%. The average balancing ratios for each day of the event are provided in **Table 14**. The balancing ratios for each five-minute interval of the event are available in Data Miner.[14]

Table 14. Summarized Balancing Ratios (BR) for Performance Assessment Intervals on Dec. 23 and Dec. 24

	Area(s)	Balancing Ratios		
		Average	Min	Max
Dec. 23 17:30–23:00	RTO	85.48%	82.23%	88.54%
Dec. 24 04:25–22:00		81.04%	77.67%	83.96%

[13] Critical Issue Fast Path – Resource Adequacy page

[14] See PJM.com, Performance Assessment Interval Final balancing ratio.

As noted in Real-Time Interchange, PJM was a net exporter of energy to neighboring systems during a significant portion of the PAIs on Dec. 23 and Dec. 24, which impacts the calculation of the balancing ratio in those intervals. During those intervals when exports exceeded imports, the Net Energy Imports figure in the balancing ratio formula is floored at zero. This has the effect of setting the balancing ratio, and subsequently the expected performance levels of committed generation, at a value that reflects both needs of the PJM system plus the assistance provided to neighboring systems in that interval. This result, of setting the balancing ratio and expected performance of committed generation capacity at a level beyond what's needed to satisfy PJM's system demand, warrants further consideration and discussion on the treatment of exports and imports in the balancing ratio and the level to which committed generation capacity should be held accountable during PAIs.

Performance Shortfall

Non-performance is measured by comparing a resource's actual performance to their expected performance to calculate a performance shortfall. This performance shortfall represents the amount of the committed capacity from the resource that was needed during the event but was not delivered to the system. The performance shortfall is calculated as: expected performance minus actual performance.

The expected performance of a resource is its CP commitment, adjusted by the balancing ratio (for generation) to account for the megawatts needed during the PAI. The actual performance of a resource is defined as the output of the resource during the event, accounting for both energy and ancillary services. The energy output is measured by the metered output (or load reduction) of the resource. The ancillary services portion of actual performance is based on the real-time regulation, Synchronized Reserves, Non-Synchronized Reserves or Secondary Reserves on the resource. The calculation for the ancillary service adjustment captures any movement off of the economic basepoint for the resource to provide the service in real time, so that the actual performance calculation credits the resource for any energy megawatts they did not produce in order to provide an ancillary service assignment.

The expected and actual performance calculations for CP resources are based on resource type:

- Generation/Storage:
  - Expected Performance = Capacity Commitment (UCAP) x Balancing Ratio
  - Actual Performance = Metered Energy Output + Reserve/Regulation Adjustment[15]
- Demand Response:
  - Expected Performance = CP Capacity Commitment (ICAP)[16]
  - Actual Performance = Load Reduction + Reserve/Regulation Adjustment[5]
- Price Responsive Demand
  - Expected Performance = CP Capacity Commitment (ICAP)

[15] For calculations for reserve and regulation assignment megawatts factored into actual performance, see the Performance Assessment Settlement Summary on PJM.com.

[16] Capacity Performance Demand Resources are only required to interrupt their load between the hours of 6:00 through 21:00 EPT for the months of November through April. As such, even though the emergency and pre-emergency load management reduction actions on the Dec. 23 did not end until 21:30 and 22:15, respectively, Capacity Performance Demand Resources were not required to curtail consumption beyond 21:00. Expected Performance is 0 MW outside the required hours of curtailment.

- Actual Performance = Load Reduction

- Energy Efficiency:
  - Expected Performance = CP Capacity Commitment (ICAP)
  - Actual Performance = PJM-Approved Post-Installation Load Reduction

If a resource's expected performance is greater than the actual performance, the resource will be assessed a non-performance penalty, unless the shortfall is excused from the performance shortfall. The reasons for excusal and the megawatts that were excused for the Winter Storm Elliott performance assessment event are discussed in the Excusal section of this paper.

The average initial shortfall across the performance assessment event, prior to excusals, was 38,068 MW. The hourly average data for the expected, actual and shortfall megawatts can be found in Table 15. Notably, actual performance across all resources in the Emergency Action area exceeds expected performance for each five-minute interval, which at first glance seems somewhat contrary to the presence of an initial shortfall. However, this is explained by performance from resources that did not have a performance obligation at the time of the performance assessment event, as well as over-performance by some resources that did have a CP obligation.

Due to the number of CP resources that exceeded the expected performance, energy-only resources that were online and generating, and net energy imports flowing into the RTO during the performance assessment event, the aggregate actual performance in all intervals was greater than the expected performance, resulting in bonus megawatts for each interval of this event.

Table 15. Aggregate Expected, Actual and Initial Shortfall Performance (hourly avg. of five-minute interval totals)

Hour Beginning (EPT)		AVERAGE		
		Expected MW Per Interval	Actual MW Per Interval	Initial Shortfall MW Per Interval
Dec. 23, 2022	17:00	142,502	144,350	35,861
	18:00	147,697	149,537	36,446
	19:00	147,850	149,788	36,566
	20:00	148,011	149,936	36,924
	21:00	147,359	149,726	37,719
	22:00	139,231	141,239	36,559
Dec. 24, 2022	04:00	131,369	133,283	39,552
	05:00	131,661	133,557	39,666
	06:00	141,681	142,127	41,179
	07:00	146,004	145,228	40,926
	08:00	147,220	147,511	39,435
	09:00	146,875	148,993	38,452
	10:00	145,829	147,957	39,210
	11:00	145,045	147,264	39,611
	12:00	144,689	146,911	39,036
	13:00	143,037	145,269	38,164
	14:00	140,860	142,988	38,448
	15:00	141,807	143,929	38,587

Hour Beginning (EPT)		AVERAGE		
		Expected MW Per Interval	Actual MW Per Interval	Initial Shortfall MW Per Interval
	16:00	144,464	146,607	38,653
	17:00	145,637	147,793	37,650
	18:00	145,211	147,327	36,820
	19:00	142,313	144,420	36,317
	20:00	134,636	136,550	34,505
	21:00	132,933	134,927	34,744

Although actual performance exceeded expected performance in aggregate for each interval, non-performance is assessed on an individual resource basis. Therefore, shortfall megawatts and associated Non-Performance Charges were assessed to resources in each of these intervals if their individual resource performance fell short of the expected megawatts. Breaking out the shortfall megawatts to a more granular level, the next few graphs and charts contain only the CP resources that had an initial shortfall. CP resources that have met or exceeded their expected performance, and energy-only resources, are excluded from these data sets. In aggregate, resources with shortfall megawatts provided 27% of their expected megawatts during the event. This aggregate performance was weighed down by the number of capacity resources on full or partial forced outages during the event.

Table 16. Expected, Actual and Initial Shortfall Performance for Under Performing Resources (hourly average of five-minute interval totals)

		AVERAGE		
Hour Beginning (EPT)		Expected MW per Interval	Actual MW per Interval	Initial Shortfall MW per Interval
Dec. 23, 2022	17:00	46,052	10,192	35,861
	18:00	49,254	12,808	36,446
	19:00	48,287	11,722	36,566
	20:00	47,773	10,849	36,924
	21:00	49,873	12,154	37,719
	22:00	47,221	10,662	36,559
Dec. 24, 2022	4:00	50,346	10,793	39,552
	5:00	50,340	10,674	39,666
	6:00	54,181	13,002	41,179
	7:00	54,893	13,967	40,926
	8:00	52,794	13,359	39,435
	9:00	51,993	13,540	38,452
	10:00	52,162	12,952	39,210
	11:00	52,497	12,886	39,611
	12:00	52,563	13,528	39,036
	13:00	54,373	16,209	38,164
	14:00	56,301	17,853	38,448
	15:00	54,230	15,643	38,587
	16:00	52,981	14,328	38,653
	17:00	53,101	15,451	37,650
	18:00	55,288	18,468	36,820
	19:00	54,934	18,616	36,317
	20:00	53,868	19,363	34,505
	21:00	52,893	18,149	34,744

Excusals

A resource's performance shortfall is evaluated for excusals and may be adjusted downward if the shortfall is deemed to be exempt. Megawatts are excused from performance if they were solely unavailable for the following reasons:

- Megawatts were on a PJM-approved planned or maintenance outage.
- Megawatts were not scheduled to operate by PJM, or were scheduled down by PJM, in alignment with the dispatch run LMP resulting from the Security Constrained Economic Dispatch and/or reliability needs.

However, if a resource was needed by PJM and would otherwise have been scheduled by PJM to perform, but was not scheduled to operate, or was scheduled down solely due to: (1) any operating parameter limitations submitted in the resource's offer, or (2) submission of market-based offer higher than cost-based offer, then these megawatts are not excused and will not result in downward adjustment of performance shortfall.

For the Winter Storm Elliott event, the average excused megawatts deemed unavailable solely due to approved maintenance and planned outages were approximately 3,800 MW. The maintenance and planned outages are in line with what can be expected in a typical winter or summer season. These outages are scheduled and approved by PJM and recallable 72 hours in advance. This is the reason these megawatts are deemed to be exempt from performance during their approved outage period. Prior to Dec. 23, PJM did not recall any generation maintenance outages, as load projections did not indicate that would be necessary. Forced outages, or outages that are unscheduled or unplanned, are not exempt from performance requirements; resources on a forced outage with a performance shortfall are assessed Non-Performance Charges.

Megawatts that were not supported by LMP, or were otherwise scheduled down by PJM, are exempt from performance penalties, because their megawatts were not needed to support the system or production of those megawatts when unneeded could have been detrimental to system reliability. It is important to system reliability during a performance assessment event that resources continue to follow PJM direction to help maintain power balance. Resources may not be scheduled by PJM due to economic reasons, such as projected system conditions and locational marginal prices (LMPs) that did not support bringing the resource online; or controlling transmission constraints that supported lowering the unit's output; or the resource is held offline or down by PJM for reserves.

Some instances of PJM manual dispatch instruction or units that were not scheduled required extensive case-by-case review by PJM staff including the review of operator logs, market data, outage data and operator conversations to determine the required level of excusal or bonus.

A more granular breakdown of the excused megawatts for each hour of the event, and the resulting final shortfall, is included in Table 17. This includes shortfalls from generation, Demand Response and Price Responsive Demand resources. Energy Efficiency resources are excluded solely because they did not have any performance shortfalls for this event. As discussed further in the

Netting for Demand Response and Price Responsive Demand section of this paper, while Demand Response and Price Responsive Demand Resources are not eligible for excusals in the same manner as generation resources, their performance shortfalls can be offset by over-performance of other resources. Any shortfall megawatts that were offset by over-performance from other resources have been included in the Average Not Scheduled column in the table below to facilitate complete accounting of final shortfall megawatts across the fleet of capacity resources. [17]

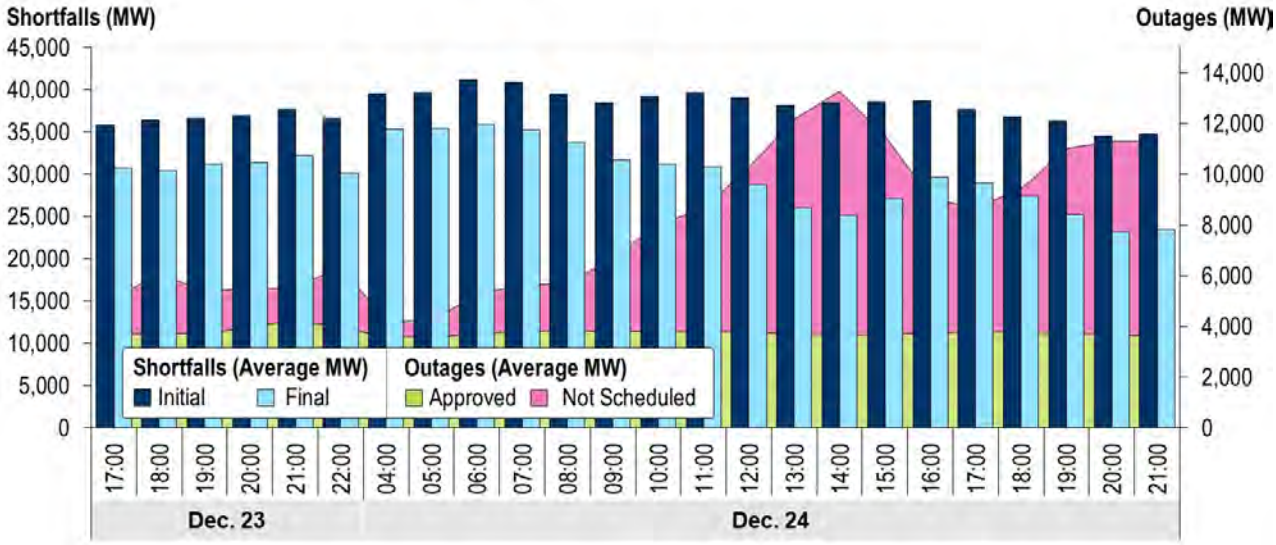
[17] The average DR and PRD shortfall megawatts offset by over-performance by other resources is 230 MW per interval.

Table 17. Initial Shortfall, Excused MW and Final Shortfall (hourly average of five-minute interval totals)

Hour Beginning (EPT)		AVERAGE			
		Initial Shortfall (MW)	Approved Outages (MW)	Not Scheduled (MW)	Final Shortfall (MW)
Dec. 23, 2022	17:00	35,861	3,674	1,469	30,718
	18:00	36,445	3,709	2,351	30,385
	19:00	36,566	3,700	1,694	31,172
	20:00	36,924	3,989	1,505	31,430
	21:00	37,719	4,238	1,262	32,219
	22:00	36,559	3,977	2,418	30,164
Dec. 24, 2022	04:00	39,552	3,581	658	35,313
	05:00	39,666	3,589	642	35,435
	06:00	41,179	3,700	1,572	35,907
	07:00	40,926	3,791	1,860	35,275
	08:00	39,435	3,827	1,826	33,782
	09:00	38,452	3,820	2,887	31,745
	10:00	39,210	3,791	4,219	31,200
	11:00	39,610	3,769	4,902	30,939
	12:00	39,034	3,759	6,528	28,747
	13:00	38,164	3,710	8,441	26,013
	14:00	38,448	3,645	9,634	25,169
	15:00	38,587	3,673	7,852	27,062
	16:00	38,652	3,751	5,305	29,596
	17:00	37,649	3,786	4,885	28,978
	18:00	36,797	3,773	5,644	27,380
	19:00	36,285	3,733	7,277	25,275
	20:00	34,505	3,657	7,640	23,208
	21:00	34,744	3,634	7,645	23,465

The average total excused megawatts in each PAI on Dec. 23 was approximately 5,600 MW per interval. The average for Dec. 24 was higher, at approximately 8,700 MW per interval. Figure 88 shows that planned outages were consistent across all intervals of the event, and that the increase in excusals on Dec. 24 was driven by higher levels of excusals for megawatts not scheduled on Dec. 24 as strain on the system eased throughout the day.

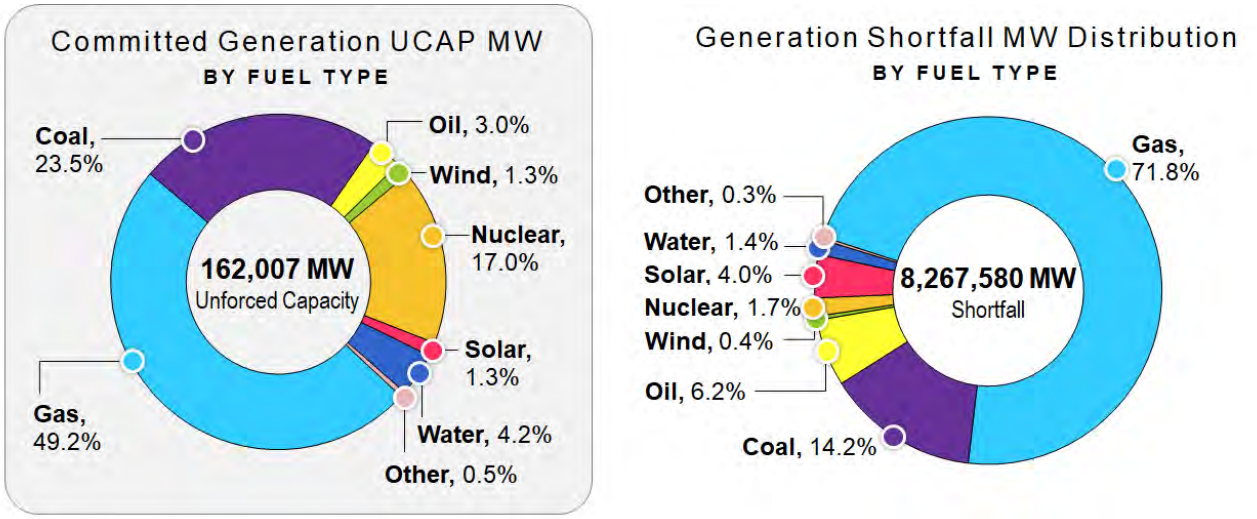
Figure 88. Excusal Megawatts and Final Shortfall MW (hourly average of five-minute interval values)



Generation Shortfall Distribution by Fuel Type

Figure 89 depicts how the final shortfall megawatts for generation resources were distributed across the generation fleet using primary fuel type. Also provided in this figure is the distribution of committed generation capacity megawatts by primary fuel type to assist in understanding how proportionate the shortfall megawatts by fuel type are to that fuel type's share of total committed generation capacity. For example, while gas units make up roughly half of committed generation capacity, they represented 71.8% of all shortfall megawatts, which tracks with the observations in the Operating Day section of this report that gas resources represented the majority of the forced outages during Winter Storm Elliott for the reasons explained therein. Solar resources also had an outsized proportion of the shortfall megawatts compared to their share of committed capacity. This is attributed to the timing of the performance assessment intervals, the majority of which occurred during hours with low levels of solar irradiance. Conversely, wind resources represented an undersized share of the performance shortfall, which tracks their strong performance noted in the Positive Observations section of this paper. The high availability factor of nuclear resources during Winter Storm Elliott resulted in the strong performance of nuclear resources and their undersized share of the shortfall megawatts.

Figure 89. Generation Shortfall MW Distribution by Fuel Type compared to Capacity Commitment



Netting for Demand Response and Price Responsive Demand

Performance shortfalls for Demand Resources deployed during a performance assessment event are evaluated as a group with all other Demand Resources in the same Emergency Action area belonging to the curtailment service provider (CSP) that committed the resource to the capacity market. For the Winter Storm Elliott event, the Emergency Action area encompassed the entire RTO, resulting in initial performance shortfall (positive or negative) of all resources belonging to the CSP being netted to determine a net performance shortfall.

In this manner, over-performance on some resources within a CSP's portfolio is able to offset under-performance on other resources in the same interval. If a CSP has a net positive shortfall of megawatts once the performance of all of its Demand Resources are netted together, the resulting shortfall is allocated to Demand Resources that under-performed pro-rata using their under-compliance megawatts. Based on this netting, a Demand Resource's final shortfall megawatts will be less than its initial shortfall megawatts if other Demand Resources in the portfolio over-performed for the same interval and were able to offset some of its shortfall.

Performance shortfalls for Price Responsive Demand (PRD) resources deployed during a performance assessment event are also evaluated as a group with all other PRD resources belonging to the provider that committed the resource to the capacity market, similar to the netting that occurs for Demand Resources.

The initial and final shortfall megawatts for Demand Resources and PRD resources during this performance assessment event are shown in Table 18. The difference between the initial and final shortfall values is reflective of the DR or PRD over-performance megawatts that was able to offset any performance shortfalls. Megawatts of over-performance that are used to net against under-performance of other resources are not eligible to receive bonus credits. The Demand Response and PRD performance values have been aggregated in the table below to adhere to posting rules around market-sensitive data given the small number of Market Participants with PRD resources.[18] For some hours, the number of combined DR and PRD Market Participants with shortfalls still does not meet the requirements for posting market-sensitive data. The data for those hours has been omitted and marked with **.

[18] PJM Manual 33, Section 6.1

Table 18. DR and PRD Initial and Final Shortfall (hourly average of 5-minute interval values)

Hour Beginning (EPT)		Average DR & PRD Initial Shortfall	Average DR & PRD Final Shortfall
Dec. 23, 2022	17:00	**	**
	18:00	583.8	267.4
	19:00	519.3	197.8
	20:00	526.4	213.7
	21:00	**	**
	22:00	0	0
Dec. 24, 2022	04:00	**	**
	05:00	**	**
	06:00	312.7	14.3
	07:00	528.3	126.3
	08:00	521.5	116.4
	09:00	433.5	38.4
	10:00	382.8	21.6
	11:00	365.3	20.8
	12:00	359.1	22.1
	13:00	337	16.3
	14:00	316.6	15.5
	15:00	315.8	14.8
	16:00	337.7	14.5
	17:00	371.6	16.2
	18:00	357.1	14.9
	19:00	88.6	11.4
	20:00	**	**
	21:00	0	0

Non-Performance Charges

Non-Performance Charge rates are calculated on a modeled RPM Locational Deliverability Area (LDA) basis for the relevant delivery year. The Non-Performance Charge rate for a specific resource is based on the Net Cost of New Entry (Net CONE) ($/MW-day in installed capacity terms) for the LDA in which such resource resides and is calculated as:

Non-Performance Charge Rate ($/MW-5-Minute Interval) =
Net CONE x Number of Days in Delivery Year / 30 Hours / 12 Intervals

The applicable charge rates for the Winter Storm Elliott PAIs for the 2022/2023 Delivery Year are detailed in Table 19.[19]

Table 19. Non-Performance Charge Rates by LDA ($/MW-5-Minute Interval)

Non-Performance Charge Rates by Locational Deliverability Area (LDA)					
ATSI	221.83	DPL-SOUTH	227.29	PS-NORTH	258.34
ATSI-CLEVELAND	221.83	EMAAC	249.60	PSEG	258.34
BGE	217.85	MAAC	235.90	RTO	250.69
COMED	238.54	PEPCO	249.76	SWMAAC	233.81
DAY	217.8	PPL	240.99		
DEOK	215.22				

These charge rates are multiplied by the final performance shortfall in each five-minute interval to determine the non-performance financial penalty for committed capacity resources. The Non-Performance Charge is calculated as:

*Non-Performance Charge = Performance Shortfall MW * Non-Performance Charge Rate*

The Non-Performance Charge for the performance assessment event totals approximately $1.80 billion, which was allocated across roughly 750 resources with final performance shortfall megawatts.

This represents 45% of the $3.97 billion in RPM auction credits paid across all committed capacity resources for the 2022/2023 Delivery Year. When isolating only the resources with shortfalls, the $1.80 billion in Non-Performance Charges represents 83% of the $2.17 billion in RPM auction credits collectively received by these under-performing resources for the 2022/2023 Delivery Year.

The hourly average and total Non-Performance Charges by hour are listed in Table 20.

[19] Modeled LDA Net CONE values for the 2022/2023 Delivery Year are available on PJM.com.

Table 20. Non-Performance Charges by Hour

Hour Beginning (EPT)		Non-Performance Charges ($)	
		Average of Interval-Level	Total Hourly
Dec. 23, 2022	17:00	6,589,973.18	39,539,839.05
	18:00	6,505,727.97	78,068,735.58
	19:00	6,731,000.98	80,772,011.71
	20:00	6,827,351.73	81,928,220.72
	21:00	7,031,512.93	84,378,155.18
	22:00	6,532,125.94	78,385,511.32
Dec. 24, 2022	04:00	7,785,599.61	54,499,197.25
	05:00	7,799,035.09	93,588,421.11
	06:00	7,733,603.22	92,803,238.65
	07:00	7,768,289.54	93,219,474.49
	08:00	7,473,896.14	89,686,753.62
	09:00	7,034,963.27	84,419,559.27
	10:00	6,910,820.64	82,929,847.71
	11:00	6,858,699.63	82,304,395.52
	12:00	6,370,314.53	76,443,774.40
	13:00	5,704,554.02	68,454,648.19
	14:00	5,508,448.92	66,101,387.04
	15:00	5,831,635.11	69,979,621.27
	16:00	6,365,883.24	76,390,598.86
	17:00	6,103,588.46	73,243,061.57
	18:00	5,739,415.91	68,872,990.94
	19:00	5,314,600.31	63,775,203.73
	20:00	4,951,402.92	59,416,835.04
	21:00	5,033,588.91	60,403,066.98
			$1,799,604,549.20

Stop-loss provisions are in place to limit the total Non-Performance Charge that can be assessed on each capacity resource. For CP resources, the maximum yearly Non-Performance Charge is 1.5 times the modeled LDA Net CONE ($/MW-day in installed capacity terms), times the number of days in the delivery year, times the maximum daily unforced capacity committed by the resource from June 1 of the delivery year through the end of the month for which the Non-Performance Charge was assessed. For all CP resources involved in the Winter Storm Elliott performance assessment event, the calculated Non-Performance Charge for the event was below the maximum yearly Non-Performance Charge. Further, for those Demand Response resources that were also subject to the performance assessment event in June 2022 earlier that same delivery year, the cumulative Non-Performance Charge for the delivery year did not exceed the maximum yearly Non-Performance Charge. As a result, it was not necessary to apply the stop-loss provision to any CP resource for the Winter Storm Elliott performance assessment event.

A resource that does not have enough unforced capacity value to cover the RPM commitment on the resource is subject to a Daily Capacity Resource Deficiency Charge. The Daily Capacity Resource Deficiency Charge is equal to the Daily

Deficiency Rate times the Daily RPM Commitment Shortage for generation resource, Demand Resource or Energy Efficiency Resource.[20]

Resources with Daily Capacity Resource Deficiency Charges may also have Non-Performance Charges during a non-performance event. In this case, a cap is placed on the total amount of deficiency-related charges a resource can be assessed. A resource that is subject to a Non-Performance Charge during one or more intervals occurring during a continuous time period of Daily RPM Commitment Shortages is assessed a charge equal to the greater of: a) the total Daily Capacity Resource Deficiency Charges calculated for shortages associated with Capacity Performance commitments for such continuous time period, or b) the total Non-Performance Charges calculated for the Performance Assessment Intervals occurring during such continuous time period.

The sum of the Daily Capacity Resource Deficiency Charges and Non-Performance Charges actually billed for such continuous time period may not exceed the resultant greater of charge. For the Winter Storm Elliott event, approximately $815,000 in Non-Performance Charges were excluded from the performance assessment billing based on this cap on total deficiency-related charges assessed to deficient resources. This $815,000 is not reflected in the values in Table 20.

Fixed Resource Requirement Shortfall Megawatts and Non-Performance Penalties

Resources that have been committed to a Fixed Resource Requirement (FRR) plan have the same obligation to perform during a performance assessment event as resources with RPM capacity commitments.

Shortfall megawatts from resources committed to FRR plans were included in the above tables summarizing resource performance and Non-Performance Charges, where applicable. Market Participants meeting their capacity obligations through FRR plans have the additional option to elect the physical non-performance assessment option.[21]

Entities that elect the FRR physical option are not assessed Non-Performance Charges and are not eligible for bonus performance credits for any performance associated with their FRR commitments. Instead, these entities must commit an additional megawatt quantity to their FRR capacity plan for the next delivery year in an amount equal to the sum of the net positive shortfalls for resources committed to their FRR plan across all five-minute intervals in the performance assessment event, multiplied by the FRR physical penalty rate.

The physical penalty rate is 0.00139 MW / Performance Assessment Interval [i.e., 0.5 MW / 30 PAHs / 12 intervals per hour]. For example, a resource with 1,000 MW of shortfall summed across all five-minute intervals in the performance assessment event would need to commit an additional 1.4 MW of capacity to their FRR plan for the delivery year following the event. In contrast, if the FRR entity for this resource instead chose the financial non-performance assessment option and was subject to the RTO Non-Performance Charge rate of $250.69/MW per five-minute interval, the resource would be assessed a charge of $250,690.

PJM is unable to report on the breakout of FRR Market Participants that have elected the physical non-performance assessment option vs. the financial non-performance assessment option or the penalties assessed to resources within their plans due to the small number of Market Participants utilizing FRR plans and requirements for posting market-sensitive data.[22]

Bonus Performance

A resource with actual performance above its expected performance is considered to have provided bonus performance, and will be assigned a share of the collected Non-Performance Charge revenues in the form of a bonus performance

[20] See PJM Manual 18, Section 9.1.3 for more information about Daily Capacity Resource Deficiency Charges.
[21] Refer to PJM Manual 11, Section 11.8.7 Physical Non-Performance Assessment.
[22] PJM Manual 33, Section 6.1

credit. Bonus performance from a resource represents greater delivered energy (or reductions), in comparison to the amount of the committed capacity from the resource that was needed during the event. Bonus performance is calculated on all over-performing resources as actual performance minus expected performance.

The expected and actual performance calculations for bonus megawatt evaluations are based on resource type:

- Generation/Storage:
  - Expected Performance = CP Commitment (UCAP) x Balancing Ratio
  - Actual Performance = Metered Energy Output + Reserve/Regulation Adjustment[23]
- Demand Response:
  - Expected Performance = CP Capacity Commitment (ICAP)
  - Actual Performance = Load Reduction + Reserve/Regulation Adjustment
- Energy Efficiency:
  - Expected Performance = CP Capacity Commitment (ICAP)
  - Actual Performance = PJM Approved Post-Installation Load Reduction
- Price Responsive Demand
  - Expected Performance = CP Capacity Commitment (ICAP)
  - Actual Performance = Load Reduction
- Net Imports
  - Expected Performance = 0 MW
  - Actual Performance = Sum (Import MW) – Sum (Export MW)

When calculating bonus megawatts, the actual performance for a generation resource is capped at the megawatt level at which such resource was scheduled and dispatched by PJM during the performance assessment event. PJM caps the megawatt level that a resource is eligible to receive bonus credit for to incent resources to follow dispatch in real time to support operations, and not chase potential bonus credits by over-generating. Resources must also have at least one available schedule with an economic minimum, economic maximum and emergency maximum, and at least one segment on the incremental energy offer curve so that PJM can determine the scheduled megawatts used in the determination of the cap. [24]

On average, approximately 2,700 MWh of energy in excess of expected megawatts was not eligible for bonus credits in each interval due to capping or failure to meet the energy offer requirements. PJM observed that a subset of these ineligible megawatts were from renewable resources that provided energy in excess of their expected megawatts. Many of these resources do not submit fuel cost policies and by default agree to be dispatched as a zero-cost resource in the

[23] The reserve/regulation adjustment made for actual performance for bonus purposes is the same as the adjustment made for shortfall calculation purposes. For calculations for reserve and regulation assignment megawatts factored into actual performance, see the Performance Assessment Settlement Summary.
[24] This rule is defined in Manual 11, Section 2.3.7.

absence of an approved fuel-cost policy. As such, these resources did not enter any segments on their Incremental Energy Offer curve and were therefore excluded from bonus payments.

The average bonus megawatts eligible for bonus credits for the Winter Storm Elliott performance assessment event was 34,318 MW per interval. On average, approximately 70% of these megawatts came from CP resources, while 30% came from energy-only resources (including net energy imports). The larger percent of bonus megawatts from the CP resources are driven by those resources being online and generating, and the average 82.1% balancing ratio. On average, resource output in excess of 82.1% of their capacity commitment, up to the megawatt level at which the resource was scheduled and dispatched, can be attributed to over-performance.

Table 21. Bonus Performance Megawatts by Hour by CP Resources and Energy Resources (hourly average of five-minute interval values)

Hour Beginning (EPT)		Average Bonus MW		Average Total Bonus MW
		CP Resources	Energy Resources	
Dec. 23, 2022	17:00	22,988.9	10,128.8	33,117.7
	18:00	23,102.9	10,827.0	33,930.0
	19:00	23,342.9	10,555.7	33,898.6
	20:00	23,825.6	10,312.1	34,137.8
	21:00	25,530.0	10,228.4	35,758.4
	22:00	23,059.9	10,717.0	33,776.9
Dec. 24, 2022	04:00	25,566.7	11,408.0	36,974.8
	05:00	25,850.1	10,984.0	36,834.1
	06:00	25,966.6	10,927.8	36,894.4
	07:00	24,469.0	11,490.8	35,959.9
	08:00	24,406.5	10,500.8	34,907.3
	09:00	25,106.4	9,974.4	35,080.8
	10:00	25,818.1	10,900.9	36,719.1
	11:00	26,328.8	10,850.1	37,178.9
	12:00	25,020.0	10,390.9	35,410.9
	13:00	22,903.1	10,435.4	33,338.6
	14:00	22,955.3	10,782.6	33,737.9
	15:00	24,371.7	10,314.0	34,685.8
	16:00	25,360.7	9,607.9	34,968.7
	17:00	23,723.6	9,569.2	33,292.8
	18:00	21,557.6	10,219.8	31,777.4
	19:00	21,716.6	9,978.6	31,695.2
	20:00	19,887.0	9,678.5	29,565.6
	21:00	21,310.7	8,681.8	29,992.6

Table 21 breaks out the average total bonus megawatts by resource type. On average, 80% of bonus megawatts were produced by generation, 10% came from net import transactions, 5% were produced by Energy Efficiency resources, and 5% were produced by Demand Response and PRD resources.

Energy Efficiency bonus megawatts are a static 1,720.9 MW across each five-minute interval of the entire performance assessment event. Actual performance for Energy Efficiency resources is established by the average demand reduction reported in the last post-installation measurement and verification report submitted by the Market Seller and approved by PJM prior to the delivery year in question.[25] Energy Efficiency resources automatically receive bonus megawatts for demand reduction in excess of their capacity commitment, as demonstrated in the post-installation measurement and verification report when a Capacity Performance event occurs.

The Demand Response and PRD bonus megawatt values include pre-emergency and emergency load management resources as well as economic Demand Resources cleared for energy or ancillary services. Pre-Emergency and Emergency Load Response resources are only required to interrupt their load between the hours of 06:00 through 21:00 EPT for the months of November through April. As such, even though the emergency and pre-emergency load management reduction actions on Dec. 23 did not end until 21:30 and 22:15, respectively, Capacity Performance Demand Resources were not required to curtail consumption beyond 21:00. The expected megawatts from these resources in the hours outside their mandatory curtailment period is 0 MW. One-hundred percent of the load reductions from pre-emergency and emergency load management resources in such hours are therefore counted as bonus megawatts. This is the reason the Average DR and PRD bonus megawatts for hour beginning 22:00 jumps five-fold from the previous hour.

Table 22. Bonus Performance Megawatts Broken Down by Resource Type (hourly average of five-minute interval values)

Hour (EPT Hour Beginning)		Average Bonus MW			
		Generation	Net Imports	EE	DR & PRD
Dec. 23, 2022	17:00	28,350.9	2,849.5	1,720.9	196.40
	18:00	27,965.0	3,490.5	1,720.9	753.50
	19:00	28,023.9	3,243.0	1,720.9	910.70
	20:00	28,410.3	3,032.2	1,720.9	974.20
	21:00	25,926.2	3,158.3	1,720.9	4,952.90
	22:00	27,974.1	3,834.8	1,720.9	247.00
Dec. 24, 2022	04:00	30,731.4	4,392.8	1,720.9	129.50
	05:00	31,103.6	3,897.8	1,720.9	111.70
	06:00	29,108.1	3,953.5	1,720.9	2,111.80
	07:00	28,213.2	4,289.4	1,720.9	1,736.30
	08:00	27,811.6	3,601.9	1,720.9	1,772.90
	09:00	28,422.5	3,084.0	1,720.9	1,853.30
	10:00	29,135.8	3,953.2	1,720.9	1,909.00
	11:00	29,514.4	3,849.5	1,720.9	2,094.10
	12:00	27,890.1	3,631.0	1,720.9	2,168.90
	13:00	25,798.2	3,603.0	1,720.9	2,216.40
	14:00	25,767.6	3,980.7	1,720.9	2,268.60
	15:00	27,083.5	3,610.1	1,720.9	2,271.20
	16:00	27,785.5	3,287.5	1,720.9	2,174.70
	17:00	26,248.9	3,254.7	1,720.9	2,068.20

[25] See PJM Manual 18, Section 4.4.1: Determination of Nominated value of EE Resources for more detail on how the average demand reduction upon which actual performance for Energy Efficiency resources is established.

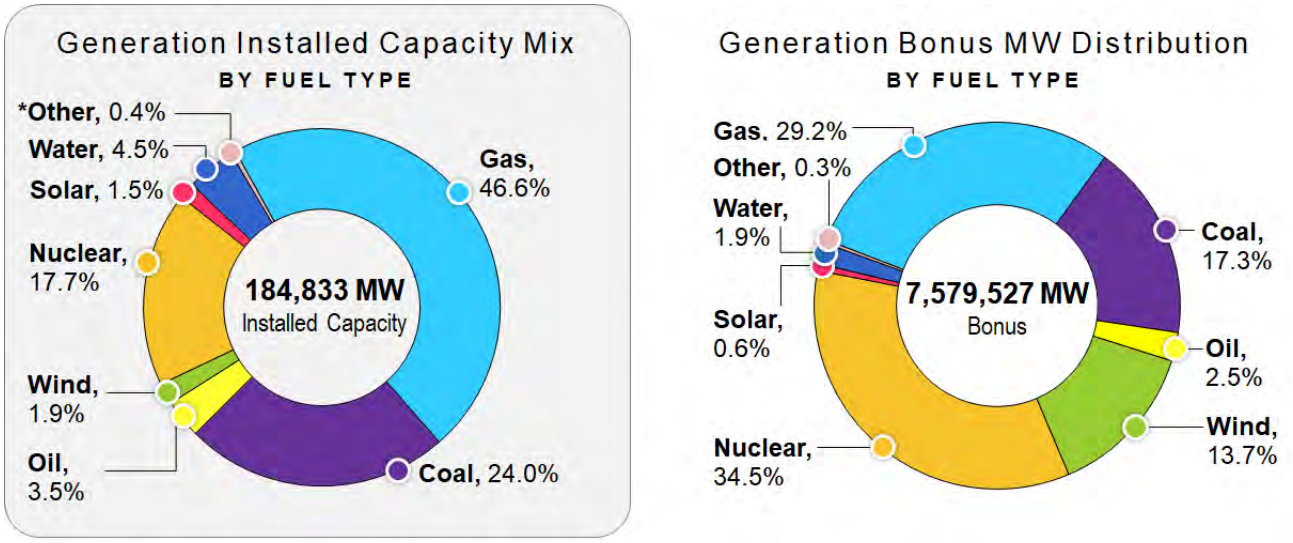
Hour (EPT Hour Beginning)	Average Bonus MW			
	Generation	Net Imports	EE	DR & PRD
18:00	24,265.0	3,670.7	1,720.9	2,120.80
19:00	23,588.6	3,549.7	1,720.9	2,835.90
20:00	23,533.7	3,461.0	1,720.9	849.90
21:00	25,954.5	2,280.0	1,720.9	37.10

Generation Bonus Performance Distribution by Fuel Type

Figure 90 depicts how the bonus performance megawatts from generation resources was distributed across the generation fleet using primary fuel type. Also provided in this figure is the installed capacity mix of the PJM generation fleet by primary fuel type to assist in understanding how proportionate the bonus performance by fuel type is to that fuel type's share of total generation capability. Consistent with their undersized portion of the shortfall megawatt pool, nuclear and wind resources in particular had outsized shares of the bonus performance pool given their strong performance during Winter Storm Elliott. Nuclear resources represented the largest share of bonus performance megawatts at 34.5%, or roughly double their share of the installed capacity mix. This stems from the high availability factor of both committed and uncommitted nuclear generation resources, the latter of which received bonus performance for all megawatts produced up to the level scheduled and dispatched by PJM.

It bears noting that these figures depict the bonus performance megawatts which received a share of bonus credits. As noted above in this section, resources that do not meet the energy offer requirements are not eligible to receive bonus performance credits and are excluded from the bonus performance megawatt values in this section.

Figure 90. Generation Bonus Performance Distribution by Fuel Type compared to Installed Capacity



Bonus Performance Rates and Credits

Total Non-Performance Charges are allocated, at the account level, as bonus performance credit to resources that have bonus megawatts based on their pro-rata share of total bonus performance megawatts. The average $/MW-interval rate across the performance assessment event for bonus megawatts was $188.85, or 75% of the non-performance penalty rate for the RTO. These rates are based on the total Non-Performance Charges assessed.

Table 23. Average Bonus Performance Rate (hourly average of five-minute interval values)

Hour Beginning (EPT)		Total Bonus MW	Total Non-Performance Charge	Bonus $/MW-Interval
Dec. 23, 2022	17:00	33,117.7	6,589,973.18	198.99
	18:00	33,930	6,505,727.97	191.74
	19:00	33,898.6	6,731,000.98	198.56
	20:00	34,137.8	6,827,351.73	199.99
	21:00	35,758.4	7,031,512.93	196.64
	22:00	33,776.9	6,532,125.94	193.39
Dec. 24, 2022	04:00	36,974.8	7,785,599.61	210.57
	05:00	36,834.1	7,799,035.09	211.73
	06:00	36,894.4	7,733,603.22	209.61
	07:00	35,959.9	7,768,289.54	216.03
	08:00	34,907.3	7,473,896.14	214.11
	09:00	35,080.8	7,034,963.27	200.54
	10:00	36,719.1	6,910,820.64	188.21
	11:00	37,178.9	6,858,699.63	184.48
	12:00	35,410.9	6,370,314.53	179.9
	13:00	33,338.6	5,704,554.02	171.11
	14:00	33,737.9	5,508,448.92	163.27
	15:00	34,685.8	5,831,635.11	168.13
	16:00	34,968.7	6,365,883.24	182.05
	17:00	33,292.8	6,103,588.46	183.33
	18:00	31,777.4	5,739,415.91	180.61
	19:00	31,695.2	5,314,600.31	167.68
	20:00	29,565.6	4,951,402.92	167.47
	21:00	29,992.6	5,033,588.91	167.83

Bonus credits paid to over-performing resources are based on Non-Performance Charges collected from under-performers. The bonus rates in the table above assume 100% collection of all Non-Performance Charges. To the extent that an account with under-performing resources is unable to pay their Non-Performance Charges, the total pool of bonus dollars to be paid out is reduced. This is achieved through the use of a bonus holdback.

Because both Non-Performance Charges and bonus credits for a given month are initially billed in the same billing statement, the amount of Non-Performance Charges that may be uncollected is unknown at the time the bill is issued. A bonus holdback is utilized to withhold an estimate of the potential uncollected Non-Performance Charges from the pool of bonus credits that are paid out in the initial bill. This hedges against the risk of paying out bonus credits that exceed the penalties that will actually be collected.

Once financial settlement occurs, PJM adjusts the bonus holdback to reflect observed nonpayment and issues adjustments to true-up the bonus credits paid with the total Non-Performance Charges collected. Ongoing reporting on the expected and actual bonus holdbacks for the billing of the Winter Storm Elliott performance assessment event is conducted at PJM Risk Management Committee meetings.[26] The Settlement Timelines and Results section of this report contains additional details on the total Non-Performance Charges to be billed each month, and therefore total potential bonus credits to be paid, as well as actual Non-Performance Charges collected as of the time this report was issued.

Resources that have been committed to an FRR plan and elected the physical non-performance assessment option had bonus megawatts calculated for the Winter Storm Elliott performance assessment events. These megawatts are not eligible to receive bonus credits. However, they are eligible to net against shortfall megawatts within the FRR entity's portfolio when calculating the amount of additional capacity the FRR entity will be required to carry in the following delivery year's FRR plan as a result of under-performance during the event. The details on the FRR physical bonus megawatts cannot be posted for data confidentiality reasons.[27]

Demand Response and Price Responsive Demand Performance

Detailed performance of DR for the Winter Storm Elliott Performance assessment event is reviewed in the Load Management Performance Report.[28] A summary of these details on performance, shortfall, bonus and penalties are detailed below. The full report can be referenced for more detailed analysis.

Table 24 summarizes Load Management (emergency and pre-emergency Demand Response) performance for the two days. For Dec. 23, all Load Management resources with 30-minute or 60-minute lead times were dispatched by PJM. For Dec. 24, all Load Management resources were dispatched by PJM (this includes all 30-minute, 60-minute or 120-minute lead times). Overall average event performance during the mandatory compliance period (06:00 through 21:00) was 126%. Capacity compliance is primarily measured based on the "firm service level" approach. This is where a resource is committed to maintain load at or below a defined level. The capacity reduction represents the megawatts reduced based on their load levels during the event, compared to their winter peak load. Capacity load reductions can be significantly different from real-time energy load reductions, since load may already be at the committed level before the resource is dispatched. This is the driver for the relatively strong Capacity Performance for this event, versus the relatively weak energy load reduction performance outlined in the Operating Day section of this report.

Table 24. Load Management Event Summary for Dec. 23 and Dec. 24

Date	Product	Average Capacity		
		Committed (MW)	Reduction (MW)	Performance
Dec. 23	Emergency Load Management	186	167	90%
	Pre-Emergency Load Management	4,042	4,907	121%
Dec. 24	Emergency Load Management	287	218	76%
	Pre-Emergency Load Management	6,888	9,035	131%

[26] Risk Management Committee web page at PJM.com
[27] PJM Manual 33, Section 6.1
[28] See Load Management Performance Report section of PJM DR web page.

Table 25 summarizes PRD performance. PRD is required to ensure load is below the committed level when there is a PAI and LMP greater than the strike price provided by the PRD provider. The capacity reduction represents the megawatts reduced based on their load levels during the event, compared to their peak load contribution.

Table 25. PRD Event Summary for Dec. 23 and Dec. 24

Date	Product	Average Capacity Committed (MW)	Average Capacity Reduction (MW)	Performance
Dec. 23	Price Responsive Demand	209	90	43%
Dec. 24	Price Responsive Demand	230	117	51%

The shortfalls from capacity commitments receive Non-Performance Charges, whereas the performance above the commitment level receives a bonus payment. Economic energy reductions and cleared ancillary services offers during the event intervals are eligible for bonus payments. The non-performance penalty and bonus breakdown for DR and PRD is detailed in Table 26. The Load Management and PRD performance values have been aggregated in the table below to adhere to posting rules around market-sensitive data given the small number of Market Participants with PRD resources. [29]

Table 26. DR and PRD Non-Performance Charges and Bonus Credits

Date	Load Management & PRD: Non-Performance Charge ($)	Load Management & PRD: Bonus Credit ($)	Economic Energy / Ancillary Services Bonus Credit ($)
Dec. 23	$2,421,812	$16,193,113.36	$2,546,949.14
Dec. 24	$1,610,469	$62,125,444.36	$5,782,104.47
Total	$4,032,281	$78,318,558	$8,329,054

Settlement Timelines and Results

Non-performance assessments are billed starting three calendar months after the calendar month that included the performance assessment event and are spread across the remaining months in the delivery year. For the Winter Storm Elliott event, this means charges are billed starting in March 2023 and spread in three equal installments through the May 2023 billing statement. However, given the magnitude of the penalties for this event, PJM filed Tariff revisions to provide participants with the option of spreading their Non-Performance Charges across a nine-month period, subject to interest for the additional six months included in this billing option.

Monthly charges are billed by dividing the total dollar amount due for each account by either three or nine months, depending on which billing option the participant selected. Participants electing the nine-month billing option were billed starting in the March 2023 billing statement and will continue to be billed through the November 2023 billing statement. Bonus credits will be paid over the same time frame, with the amount credited each month equal to the amount of Non-Performance Charges collected each month. Based on the aforementioned elections, $524 million, or 30% of the total

[29] PJM Manual 33, Section 6.1

$1.8 billion in Non-Performance Charges for this event, will be billed over a three-month period. The remaining $1,276 million, or 70%, will be billed over a nine-month period and will be assessed $15 million in interest charges. [30]

The following table displays the total charges to be assessed each month, the total Non-Performance Charges that were not collected, and the resulting bonus credits available to be paid to bonus recipients as of June 21, 2023. Ongoing updates will be provided through the PJM Risk Management Committee meetings.

Table 27. Non-Performance Charges and Bonus Credits Invoiced

Billing Month	Total Non-Performance Charges ($)	Total Interest Charges ($)	Total Nonpayment ($)	Total Bonus Credits Paid (including interest) ($)
March 2023	$316,419,632.80	$1,704,168.62	$8,422,793.53	$309,701,007.89
April 2023	$316,419,632.80	$1,704,168.62	$7,877,961.45	$310,245,839.97
May 2023	$316,419,632.80	$1,704,168.62	$7,875,909.02	$310,247,892.40
June 2023	$141,724,275.13	$1,704,168.62	TBD	TBD
July 2023	$141,724,275.13	$1,704,168.62	TBD	TBD
August 2023	$141,724,275.13	$1,704,168.62	TBD	TBD
September 2023	$141,724,275.13	$1,704,168.62	TBD	TBD
October 2023	$141,724,275.13	$1,704,168.62	TBD	TBD
November 2023	$141,724,275.13	$1,704,168.62	TBD	TBD
Total	$1,799,604,549.20	$15,337,517.54	$24,176,664.01 (as of 6/21/2023)	$930,194,740.26 (as of 6/21/2023)

Government, Member and Media Outreach

PJM's Corporate Communications, Federal, and State & Member Services teams are responsible for communicating situation updates to, and answering inquiries from, the general public, stakeholders, and state and federal contacts through direct channels, as well as PJM.com, social media and traditional media. Corporate Communications regularly participates in PJM's annual Operations Winter Emergency Procedures Drill and Summer Emergency Procedures Drill. These drills include a call with Transmission Owner communications departments, in which a PJM Operations supervisor and PJM external communications staff provide a situation update and information on how PJM contacts them if needed in an emergency, including through an emergency alert tool managed by PJM's Business Continuity Department. Corporate Communications conducts a roll call of communicators during these drills and uses the occasion to update its Transmission Owner communicator contact list.

PJM's State Government Policy (SGP) Department prepares for emergency procedure communications and coordination with state emergency contacts throughout the year. These state emergency contacts, categorized by email and phone number (all-call list), are informed by the state agencies within the PJM footprint and serve as the primary point of contact to receive standard PJM emergency procedure notifications, which are sent by the designated on-call SGP employee.

SGP tests its ability to successfully communicate with the state emergency email and all-call lists during PJM's summer and winter emergency drills, as well as other emergency drills, such as the November 2022 Grid Security Drill. These summer and winter drills allow for state emergency contacts to familiarize (or re-familiarize) themselves with PJM's

[30] The interest charges collected on a monthly basis will be allocated to bonus performance credit recipients based on their ratio share of total bonus performance credits (under the assumption of 100% collection of all Non-Performance Charges).

emergency notifications, help PJM test its emergency communication channels with the states, and provide biannual checkpoints for PJM to curate the state emergency contact lists. The state emergency contact lists are also updated on an ad-hoc basis.

PJM external-facing communicators also participate in biannual GridEx exercises and Grid Security Drills, coordinating with both member communicators and other ISOs/RTOs as part of the scenarios.

Beginning with the 2021/2022 winter season, SGP and Operations leadership began holding winter operations calls with the PJM states to discuss winter preparedness and operational developments throughout the winter. The calls continued for the 2022/2023 winter season, with one meeting held with the states on Dec. 15, 2022.

The activation of PJM's crisis communication plans and outreach to members, states and the general public through national/local/social media appeared to help reduce electricity use and ensure the reliability of the grid. Member communicators expressed appreciation for PJM's handling of the media and willingness to do local media interviews. In addition, PJM continues to seek additional feedback on opportunities for better coordination to refine and enhance its crisis communications and outreach procedures.

The outreach by Corporate Communications, State & Member Services, and other PJM employees, and coordinated response by both member companies and state partners was effective. The Call for Conservation, which depends on members to relay the message to their retail customers, and the impact of consumers' resulting efforts, appeared to have led to a reduction in demand. Though it is difficult to measure precisely, electricity demand leveled off over the course of Saturday, and peak demand Saturday evening came in less than what was forecast.

While the conservation effort appeared to be successful, PJM is exploring further opportunities to maximize the reach of such appeals with states and Transmission Owners.

Event Communications

Starting on Dec. 21 through Dec. 23, Corporate Communications published on its news site, Inside Lines, a series of articles noting the Cold Weather Advisory and subsequent Cold Weather Alert updates, and amplified them on social media. On Dec. 23, conditions deteriorated as more generators continued to go offline, resulting in a Call for Conservation.

A Call for Conservation, as outlined in Manual 13, "instructs affected Transmission Owners to request the public to conserve electricity because of developing power supply problems." Transmission Owners are the most logical point of contact for retail customers, with PJM also broadcasting the conservation appeal via news release, PJM.com, social media and traditional media.

The decision to issue a Call for Conservation was made at approximately 23:30 on Friday, Dec. 23, so that both Transmission Owners and PJM's press release would reach any outlets or audiences that could respond late Friday into early Saturday morning and have some impact on the morning peak. PJM Corporate Communications and State & Member Services teams relayed system conditions and the Call for Conservation to the communications staff of PJM Transmission Owners, as well as state regulators and elected officials, throughout Winter Storm Elliott from Dec. 23 to Dec. 25.

Corporate Communications posted a news release on PJM.com at 23:54 and sent the release via email to Transmission Owner communicators, members and media contacts, and posted to Twitter and LinkedIn. PJM reissued the news release to our extensive media and member communicators' contact lists at 05:40, Dec. 24, and retweeted the Call for Conservation news release.

Corporate Communications activated its crisis communications plan at 05:45, Dec. 24, to make sure sufficient resources were available to handle outreach and media response needs Saturday and Sunday.

PJM noted the end of the Call for Conservation on Sunday, Dec. 25, with direct email to members, social media posts and video on PJM.com.

Transmission Owner Communicators

At approximately 21:50, Friday, Dec. 23, before PJM had made the decision to issue a Call for Conservation, PJM Corporate Communications scheduled a meeting with Transmission Owner communicators for 08:30, Saturday, Dec. 24, to provide utility partners a situational update. PJM also directly emailed Transmission Owner communicators the news release shortly after 00:00 Saturday.

This 08:30 Saturday meeting became PJM's main venue to request these members' support in broadcasting the Call for Conservation appeal. More than 30 partners (including elected officials and regulators in addition to members) joined in the effort to amplify the Call for Conservation to their customers, gaining nearly 1 million impressions on Twitter alone. PJM believes that the actions of these members, combined with PJM media outreach, helped to broadcast the Call for Conservation and flatten the load beginning at 07:15 Saturday, when the New Jersey Board of Public Utilities issued the first tweet in response to PJM's call.

PJM held an event review with Transmission Owner communicators on Jan. 9. This discussion informed Corporate Communications' observations and lessons learned from the event. Transmission Owner communicators stated that PJM's willingness to do interviews with local media was helpful to them as they dealt with both distribution outages and the transmission challenges highlighted by the Call for Conservation.

Federal

During the winter storm, PJM's Federal Government Policy group kept in close contact with FERC and the Department of Energy (DOE), consistent with its regular practice when emergency procedures are invoked. Communications are directed to FERC commissioners and their advisors, as well as to staff, throughout the Commission and reports on the system conditions with updates after the morning and evening peaks. In addition, PJM utilizes FERC's emergency notification procedures for such notices. PJM's reporting requirements to FERC are identified in in PJM Manual 13 and NERC Standard EOP-4.

In addition, the Federal Government Policy group similarly reaches out to DOE officials in the office of Cybersecurity, Emergency Security and Emergency Response (CESER) with updates after the morning and evening peaks. These early communications represented an early reach-out prior to PJM seeking to invoke the Section 202(c) process to obtain an emergency order from the Secretary of Energy.

Public/Media

PJM posted three video updates from System Operations leadership at the top of PJM.com homepage. The video was retweeted and reposted by customer-facing members as well as elected officials and regulators, used by State & Member Services to inform key stakeholders, and quoted or captured directly by media for use in broadcasts.

PJM responded to approximately 50 media requests, including at least 20 interviews on Dec. 24 and Dec. 25. PJM worked with customer-facing members' communications departments, who referred inquiries to PJM. In follow-up discussions, these members indicated that PJM's willingness to handle local media requests freed them to handle other pressing issues at the distribution level.

PJM deployed Twitter, LinkedIn and Facebook to draw attention to the video updates provided on PJM.com. Posts promoting the video received more than 300,000 impressions. Total impressions from PJM posts during Winter Storm Elliott were:

Twitter – 519,298	Facebook – 27,368	LinkedIn – 27,182

The PJM Now app is a popular source for system alerts (including emergency procedures) and allows users to track energy use, fuel mix and emissions data. More than 1,800 unique users accessed the app during Winter Storm Elliott, and the app was opened 6,600 times on Dec. 25 – compared with an average daily use of 750 app opens. The PJM Now app experienced unprecedented usage that slowed service during the storm, and PJM's Inside Lines news site went down Saturday because of unprecedented usage. Corporate Communications has taken steps to enhance these platforms so that similar usage levels will not result in the same performance issues as experienced during Winter Storm Elliott.

Between Dec. 23 and Dec. 25, Corporate Communications tracked more than 70 news stories noting PJM's Call for Conservation. This included national and newswire coverage from CNN, the Associated Press and Bloomberg, as well as regional coverage from television, radio and print media throughout the region PJM serves.

States

Heading into Winter Storm Elliott, SGP began its emergency procedure communications with the states on Dec. 21, relaying the issuance of a Cold Weather Alert for the Western Region of PJM on Dec. 23. SGP then communicated the issuance of a second Cold Weather Alert on Dec. 23 for the entire PJM region that began on Dec. 24.

As the storm progressed on Dec. 23 and emergency conditions arose, SGP relayed PJM's emergency procedure positioning to the state emergency email contacts as this information was provided to SGP by PJM's Operations Team. This included the escalation and de-escalation of emergency conditions heading into Dec. 24. SGP also communicated PJM's Dec. 24 Call for Conservation to the states, but instead of sending the conservation message to just the standard state emergency contacts, SGP utilized a broader list of state contacts that also included the emergency contacts.

In addition to member utilities, social media reach was greatly extended by participation of elected officials. Two governors tweeted the Call for Conservation and attracted two of the top three Twitter impression totals. Corporate Communications and SGP are working together to maximize impact from state partners when issuing a conservation appeal.

As SGP continued to provide system condition updates to its state emergency contacts the morning of Dec. 24, these communications progressed to individualized updates to the states via the SGP regulatory managers. Periodic system condition updates continued to be provided to the standard state emergency contacts through Dec. 25, although no new emergency procedures were issued by PJM.

Stakeholders

Figure 91 presents the stakeholder messages made between Dec. 23 and Dec. 25, color-coded by audience. These communications are in addition to direct communications made to generators, Load Serving Entities, Market Participants and others in emergency conditions as well as normal operating situations. General email notifications about the start and end of Performance Assessment Intervals are made for general awareness of all members. Members directly impacted by Performance Assessment Intervals receive separate, direct notifications in real time.

Figure 91. Stakeholder Messages

Type	Audience	Message	Time Sent Dec. 23	Dec. 24	Dec. 25
	Stakeholders	Notifying the beginning of a Performance Assessment Interval	19:01		
	Transmission Owner communications departments	A winter operation update conference call to be held with PJM Corporate Communications at 08:30, Dec. 24.	21:54		
	Stakeholders	The Maximum Emergency Generation Action has ended at 23:00, Dec. 23, along with the corresponding Performance Assessment Interval.	23:32		
	Stakeholders	The issuance of a public call for electricity conservation shortly before midnight		00:31	
	Stakeholders	General email notification to stakeholders, notifying the beginning of a Performance Assessment Interval		05:19	
	PJM news release distribution list	On public Call for Conservation sent to PJM news release distribution lists		05:40	
	Generation Owners with actual/potential emission restrictions	Update and maintain this information in Markets Gateway for PJM to prepare a 202(c) filing with the Department of Energy.		10:31	
	Stakeholders	PJM's 202(c) filing with the Department of Energy requesting for a finding that an electricity reliability emergency exists within the PJM region		17:38	
	Stakeholders	On the Department of Energy's issuance of the requested emergency order and providing the names, municipalities and zip codes of the generation resources subject to the order		19:27	
	Stakeholders	The Maximum Emergency Generation Action has ended at 20:00, Dec. 24, along with the corresponding Performance Assessment Interval.		22:14	
	Stakeholders	Announcing the end of the public call for electricity conservation			11:54
	Market Participants	Announcing that Dec. 26 Day-Ahead Market results are posted and that the rebid period was extended to 14:45			14:31

Maximum Generation Emergency Action Email
Email Notification
PJM New Release Distribution List
Generation Owner Request
Technical Communication

Conclusion

The observations and recommendations in this report were developed through intensive data gathering, analysis and feedback from various groups regarding areas of study. Learning Teams were convened for operations and markets that included subject matter experts not directly involved in this report, adding their independent evaluation of the research presented.

Extreme events like Winter Storm Elliott offer opportunities to improve our rules, practices, preparations and processes. Following the 2014 Polar Vortex, PJM took important steps to improve reliability by implementing Capacity Performance incentives for generation to perform during emergencies, strengthening winterization rules and refining operating procedures.

In 2021 following the lessons of Winter Storm Uri that impacted Texas and surrounding regions, PJM introduced rules to help Transmission Owners ensure service to critical facilities in emergencies, improve information sharing with the natural gas industry, and strengthen load-shedding preparation and practices. PJM also enhanced data gathering from generating resources, including more frequent fuel and equipment inventory reporting in the face of global supply chain issues. In advance of the 2022/2023 winter, PJM updated its winter preparation generator checklist to include cold weather operating limits.

The 30 recommendations listed at the outset of this report will be acted on through multiple stakeholder forums, including the ongoing Critical Issue Fast Path – Resource Adequacy process that was initiated to produce a set of improvements to PJM capacity market rules by October. Other recommendations will be pursued in various PJM forums to include the Electric Gas Coordination Senior Task Force, Operating Committee and the Market Implementation Committee.

While PJM and its members were able to maintain reliability during Winter Storm Elliott, the increasing volatility of weather patterns and reliance on gas generation underscore the need to advance the performance of operations, planning and markets for the increasing risk presented by the winter season.

Appendix A

Two-Settlement Market Mechanics

As described in the Operating Day section of this report, the PJM Energy Market consists of two markets: a Day-Ahead Market and a Real-Time Market. The Day-Ahead Energy Market offers an opportunity for Market Participants to lock in their positions in advance of an operating day in a financially firm way to reduce their risk of exposure to real-time prices.

Market Participants have until 11:00 the day prior to the operating day to submit their bids and offers for the Day-Ahead Market. Generation resources, regardless of fuel type, fall into one of two categories, Capacity Resources or Energy Resources. If available, all Generation Capacity Resources that have a Reliability Pricing Model (RPM) or Fixed Resource Requirement (FRR) Commitment must submit offer data into the Day-Ahead Market and may elect either to Self-Schedule or offer the resource to PJM for scheduling as a PJM RTO-Scheduled Resource. Several types of entities participate in the Day-Ahead Energy Market.

- Generation Owners submit their offers to supply power and will adjust offers for factors, such as cost of fuel.
- Load Serving Entities will submit bids for their expected need for electricity for the operating day. For a typical operating day, PJM observes approximately 90–95% of real-time load cleared in the Day-Ahead Market with the remainder clearing and settling in the Real-Time Market.
- Market Participants also may submit various “virtual transactions,” which are offers to buy or sell at particular locations that are generally not associated with physical generation or load. Market Participants may use virtual transactions for various reasons including hedging risk on physical positions and arbitraging price differences between the Day-Ahead and Real-Time Markets.

When the Day-Ahead Market closes at 11:00 on the day prior to an operating day, PJM begins the process of clearing the Day-Ahead Market, and the results are made available to Market Participants by 13:30 the day prior to the operating day. The Day-Ahead Market is cleared so that the cost to serve physical and virtual demand is minimized, while still respecting the physical operating limits of the transmission system. Commitments in the Day-Ahead Market are financially binding on participants. Any differences between those commitments and what occurs in the operating day is settled in the Real-Time Energy Market.

Generation and Demand Resources may alter their offers for use in the Real-Time Energy Market during the following periods:

- The Generation Rebidding Period, which is defined from the time the office of interconnection posts the results of the Day-Ahead Energy Market until 14:15
- Starting at 18:30 (typically after the Reliability Assessment and Commitment Run is completed) and up to 65 minutes prior to the start of the operating hour

There are often cases where the load levels cleared in the Day-Ahead Market do not meet the level of forecasted load for the operating day. To address this, PJM has a process called the Reliability Assessment Commitment (RAC) that begins after 16:15, which commits additional supply to meet the forecasted load plus reserves, while minimizing start-up and no-load cost of those commitments. The focus of this commitment is reliability and the objective is to minimize start-up and no-load costs for any additional resources that are committed. Using the most up-to-date weather forecast, load forecast, transmission facility and generator availability, and other information, PJM commits additional supply, if necessary, to satisfy both expected loads and the needed reserves for the operating day.

Leading up to and throughout the operating day, PJM examines updated information and system conditions and acts to continually balance generation with the need for electricity and maintaining adequate reserves to prepare for unexpected issues. PJM manages changes from day-ahead commitments and schedules in the Real-Time Energy Market using the offers from generation resources and Demand Resources to jointly minimize the cost of energy and reserves while maintaining energy balance and respecting the limits of the transmission system. Any differences in supply and demand from the Day-Ahead Energy Market commitments are settled at price levels determined by the Real-Time Energy Market.

Energy and Reserve Market Pricing

Locational Marginal Price (LMP) is defined as the marginal price for energy at the location where the energy is delivered or received and is based on forecasted system conditions and the latest approved Real-Time Security Constrained Economic Dispatch program solution. LMP is expressed in dollars per megawatt-hour ($/MWh). LMPs are determined as an output of the co-optimization of energy and reserves and is the cost to provide the next increment of energy while respecting reserve requirements, transmission constraints and losses.

PJM's real-time dispatch and LMP calculation systems include Operating Reserve Demand Curves (ORDCs) for 30-minute Operating Reserves, Primary Reserves and Synchronized Reserves. During times where an area of PJM is experiencing a reserve shortage, those ORDCs are used to set reserve prices and may have a direct impact on LMPs. Specifically, when the marginal energy megawatts are provided by converting a megawatt of reserves into a megawatt of energy, the resulting LMP takes into account the opportunity cost of that exchange. This direct impact of the ORDCs on LMPs during a reserve shortage is referred to as shortage or scarcity pricing. More information on this is contained in PJM Manual 11.

In performing this LMP calculation, the cost of serving an increment of load at each bus from each resource associated with an eligible energy offer is calculated as the sum of the following three components of LMP:

- System Energy Price – This is the system-wide, unconstrained price. The System Energy Price may include a portion of the defined Reserve Penalty Factors should a reserve shortage exist.
- Congestion Price – This is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from or consumption by the resource on transmission line loadings.
- Loss Price – This is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from or consumption by the resource on transmission losses.

LMPs are calculated in both the Day-Ahead Energy Market and the Real-Time Energy Market. The Day-Ahead LMP is calculated based on the Security Constrained Economic Dispatch for the Day-Ahead Market. The Real-Time LMP is calculated based on the approved Security Constrained Economic Dispatch solution for the target dispatch interval.

PJM procures resources to meet the required Reserve Services in the Day-Ahead Reserve Markets:

- Synchronized Reserve Service – Reserve capability that can be converted fully into energy or load that can be removed from the system within 10 minutes of the request from the PJM system operator and must be provided by equipment electrically synchronized to the system. Synchronous Reserves can only be satisfied by online resources that are able to respond in 10 minutes or less.

- Contingency (Primary) Reserve Service – Reserve capability satisfied by online or offline resources that are able to respond in 10 minutes or less. Contingency (Primary) Reserve is reserve capability that can be converted fully into energy or load that can be removed from the system within 10 minutes of the request from the PJM system operator.
- 30-Minute Reserve Service – Reserve capability satisfied by online or offline resources that are able to respond in 30 minutes or less.

Figure 92 presents the relationship among the three reserve services described above.

Figure 92. Reserve Services



Regulation Market

The PJM Regulation Market provides PJM participants with a market-based system for the purchase and sale of the Regulation ancillary service. Resource owners submit specific offers for Regulation Capability and Regulation Performance, and PJM utilizes these offers together with energy offers and resource schedules from the Markets Gateway System as input data to the Ancillary Service Optimizer (ASO), which is an hour-ahead Market Clearing Engine. ASO optimizes the RTO dispatch profile and forecasts LMPs to determine hourly commitments of Regulation to meet the requirement. The Real-Time Security Constrained Economic Dispatch (RT SCED) program jointly optimizes Energy and Reserves subject to transmission constraints, Reserve Requirements and prior committed Regulation.

The five-minute Regulation Market Clearing Price (RMCP) and Regulation Market Performance Clearing Price (RMPCP), are calculated by the Locational Price Calculator and are used to derive the five-minute Regulation Market Capability Clearing Price (RMCCP). These clearing prices are then used in market settlements to determine the credits awarded to providers and charges allocated to purchasers of the Regulation service.

PJM uses resource schedules, Regulation offers, and energy offers from the Markets Gateway System as input data to the ASO to provide the lowest cost alternative for the procurement of Regulation for each hour of the operating day. The lowest cost alternative for this service is achieved through a co-optimization with Synchronized Reserves, Primary Reserves, 30-Minute Reserves and energy. Within the co-optimization, an RTO dispatch profile is forecasted along with LMPs for the market hour. Using the dispatch profile and forecasted LMPs, an opportunity cost, adjusted by the applicable Performance Score and Benefits Factor, is estimated for each resource that is eligible to provide Regulation. The estimated opportunity cost for Demand Resources is zero. The adjusted lost opportunity cost is added to the adjusted regulation capability cost and the adjusted regulation performance cost to make the adjusted total regulation offer cost. The adjusted total regulation offer cost is then used to create the merit order price.

All available regulating resources are then ranked in ascending order of their merit order prices, and the lowest cost set of resources necessary to simultaneously meet the PJM Regulation Requirement, PJM Synchronized Reserve Requirement, PJM Primary Reserve Requirement, and PJM 30-minute Reserve Requirement and provide Energy in that hour is determined. If there is an excess of self-scheduled and zero-cost offers over and beyond the Regulation Requirement, PJM uses resource-specific historic performance scores, selecting those resources with the highest performance scores, as a tie-breaker to determine which set of resources to commit to meet the Regulation Requirement. The least cost set of Regulation resources identified through this process are then committed.

Prices for Regulation are calculated simultaneously with Energy and Reserves every five minutes by the Locational Pricing Calculator (LPC) in the pricing run. The highest merit order price associated with this lowest cost set of resources awarded Regulation becomes the RMCP. The RMPCP is calculated as the highest adjusted performance offer from the set of cleared resources. The RMCCP is the difference between RMCP and RMPCP.

Financial Transmission Rights

Financial Transmission Rights (FTRs) are financial instruments awarded to bidders in the FTR Auction and entitle the holder to receive a stream of revenues (or charges) based on hourly Day-Ahead Congestion Price differences across a path. They provide hedging and protections against future locational energy price differences.

A Market Participant can obtain FTRs in the Annual Auction, Long-Term Auctions, Monthly Auction and secondary market.

PJM awards FTRs based on the capability of the transmission system. There must be adequate revenue from congestion to fund the FTRs that are awarded. Revenue adequacy issues occur when PJM under-collects congestion revenue to fund FTRs.

The hourly economic value of an FTR Obligation is based on the Financial Transmission Right MW reservation and the difference between the Day-Ahead Congestion Price at the point of delivery and the point of receipt of the Financial Transmission Right. The hourly economic value of a Financial Transmission Right Obligation is positive (a benefit to the FTR holder) when the Day-Ahead Congestion Price at the point of delivery is higher than the Day-Ahead Congestion Price at the point of receipt. The hourly economic value of a Financial Transmission Right Obligation is negative (a liability to the FTR holder) when the Day-Ahead Congestion Price at the point of receipt is higher than the Day-Ahead Congestion Price at the point of delivery.

The hourly economic value of a Financial Transmission Right Option is based on the Financial Transmission Right MW reservation and the difference between the Day-Ahead Congestion Price at the point of delivery and the point of receipt of the Financial Transmission Right when that difference is positive. The hourly economic value of a Financial Transmission Right Option is positive (a benefit to the FTR holder) when the Day-Ahead Congestion Price at the point of delivery is higher than the Day-Ahead Congestion Price at the point of receipt. The hourly economic value of a Financial Transmission Right Option is zero (neither a benefit nor a liability to the FTR holder) when the Day-Ahead Congestion Price at the point of receipt is higher than the Day-Ahead Congestion Price at the point of delivery.

The total target allocation for a Market Participant for each hour is then the sum of the target allocations for all of the Market Participant's FTRs. Note, if the DA LMPDelivery or the DA LMPReceipt is an aggregate zone, the following formula is used:

$$Target = FTR * \Sigma Load\ Percentage * (DALMPDelivery - i - DALMPReceipt)$$

Where:

- FTR Financial Transmission Rights between the designated Load Aggregation Zone and the designated bus, in megawatts
- Load Percentage – the percentage of the load at time of annual peak associated with each individual load bus in the Load Aggregation Zone designated in the FTR

PJM compares the total of all Transmission Congestion Credit target allocations to the total Transmission Congestion Charges for the PJM Control Area in each hour resulting from the Day-Ahead Market.

- If the total of the target allocations is less than the total Day-Ahead Transmission Congestion Charges, the Day-Ahead Transmission Congestion Credit for each FTR is equal to its target allocation. All excess Day-Ahead Transmission Congestion Charges are distributed at the end of the month.
- If the total of the target allocations is equal to the total Day-Ahead Transmission Congestion Charges, the Day-Ahead Transmission Congestion Credit for each FTR is equal to its target allocation.
- If the total of the target allocations is greater than the total Day-Ahead Transmission Congestion Charges, the Day-Ahead Transmission Congestion Credit for each FTR is equal to its target allocation only for those customer accounts whose total target allocation position for their FTR portfolio is net negative for the hour. Customer accounts whose total target allocation position for their FTR portfolio is net positive for the hour receives a share of the total Day-Ahead Transmission Congestion Charges (including revenues resulting from the collection of the net negative target allocation positions) in proportion to its target allocation. The shortfalls in hourly Day-Ahead Transmission Congestion Credits compared to target allocations may be offset by excess charges from other hours in the end of the month accounting.
- If the total Day-Ahead Transmission Congestion Charges is negative, the Day-Ahead Transmission Congestion Credit for each FTR is equal to its target allocation only for those customer accounts whose total target allocation position for their FTR portfolio is net negative for the hour. If the revenues resulting from the collection of the net negative target allocation positions is more than enough to cover the negative Day-Ahead Transmission Congestion Charge, then any remaining revenues are distributed as Day-Ahead Transmission Congestion Credits to customer accounts whose total target allocation position for their FTR portfolio is net positive for the hour, in proportion to their target allocations. If the revenues resulting from the collection of the net negative target allocation positions is not enough to cover the negative Day-Ahead Transmission Congestion Charge, then no Day-Ahead Transmission Congestion Credits are awarded to customer accounts whose total target allocation position for their FTR portfolio is net positive, and the remaining Day-Ahead Transmission Congestion Charge liability will be subtracted from the total monthly excess prior to the month-end distribution described in the next section. The shortfalls in hourly Day-Ahead Transmission Congestion Credits compared to target allocations may be offset by excess charges from other hours in the end of the month accounting.

Errata

1 | Pages 53 and 54, Figures 35 and 36: Legend colors swapped:

- Orange: No Day-Ahead Commitment
- Blue: Day-Ahead Commitment

2 | Page 73, Figure 60: Y Axis changed to show the increment thousands

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-9

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

Exhibit 45

DOE Order No. 202-21-1

Department of Energy
Washington, DC 20585

Order No. 202-21-1

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and for the reasons set forth below, I hereby determine that an emergency exists in Texas due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

On February 14, 2021, the Electric Reliability Council of Texas (ERCOT), the Independent System Operator (ISO) whose service territory includes 90 percent of the electric customers in the state of Texas, filed a *Request for Emergency Order Under Section 202(c) of the Federal Power Act* (Application) with the United States Department of Energy (Department) "to preserve the reliability of bulk electric power system."

ERCOT is in the beginning stages of an unprecedented cold weather event brought on by a rare, southward excursion of the jet stream into the South Central United States. Temperatures for Sunday and Monday in many parts of Texas are forecasted to drop well below the lowest temperatures experienced in several decades, and abnormally low temperatures are expected to persist for several more days. This weather event is expected to result in record winter electricity demand that will exceed even ERCOT's most extreme seasonal load forecasts.

On February 12, 2021, Greg Abbott, the Governor of the State of Texas declared a state of disaster in all 254 Texas counties due to severe weather posing an "imminent threat of widespread and severe property damage, injury, and loss of life due to prolonged freezing temperatures, heavy snow, and freezing rain statewide." On the morning of February 14, ERCOT issued a system-wide conservation notice addressing the expected system emergency and describing steps that homeowners and businesses can take to reduce system demand.[1] ERCOT has also worked with state agencies to take measures that maximize generation availability in Texas. For example, on February 12, the Railroad Commission of Texas issued an Emergency Order pursuant to Texas Utilities Code affecting the gas utility systems in the state. The order specified increasing the priority of gas supplies to ERCOT generators. ERCOT's application also noted that the "Texas Commission on Environmental Quality has indicated that it will provide enforcement discretion to generators in the ERCOT region that may exceed state emissions requirements during emergency conditions."

According to ERCOT, the measures taken by ERCOT and other state agencies may not prove sufficient to avoid rotating outages of as much as 4,000 MW. Moreover,

[1] ERCOT, *Grid Operator Requests Energy Conservation for System Reliability*, www.ercot.com/news/releases/show/225151.

ERCOT has been alerted that numerous generation units will be unable to operate at full capacity without violating federal air quality or other permit limitations.

ERCOT requests that the Secretary issue an order immediately, effective February 14, 2021 through February 19, 2021, authorizing "the provision of additional energy from all generation units subject to emissions or other permit limits" in the ERCOT region. The generating units (Specified Resources) that this Order pertains to are listed on the Order 202-21-1 Resources List, as described below.

Given the emergency nature of the expected load stress, the responsibility of ERCOT to ensure maximum reliability on its system, and the ability of ERCOT to identify and dispatch generation necessary to meet the additional load, I have determined that additional dispatch of the Specified Resources is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation, with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts. ERCOT anticipates that this Order may result in exceedance of emissions of sulfur dioxide, nitrogen oxide, mercury, and carbon monoxide emissions, as well as wastewater release limits. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by ERCOT for reliability purposes.

Based on my determination of an emergency set forth above, I hereby order:

A. From February 14, to February 19, 2021, in the event that ERCOT determines that generation from the Specified Resources is necessary to meet the electricity demand that ERCOT anticipates in Texas during this event, I direct ERCOT to dispatch such unit or units and to order their operation only as needed to maintain the reliability of the power grid in the ERCOT region when the demand on the ERCOT system exceeds expected energy and reserve requirements. Specified Resources are those natural gas, coal, or distillate fuel oil generating units set forth on the Order 202-21-1 Resource List, subject to updates directed here and as described in paragraph D, which the Department shall post on www.energy.gov. ERCOT is directed to update Exhibit A to its Application with the anticipated category of environmental impact (i.e. sulfur dioxide, nitrogen oxide, mercury, carbon monoxide emissions, wastewater release, other air pollutants) by 21:00 Central Standard Time on February 15, 2021.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by ERCOT for reliability purposes. Consistent with good utility practice, ERCOT shall exhaust all reasonably and

practically available resources, including available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions, to the extent that such resources provide support to maintain grid reliability, prior to dispatching the Specified Resources. ERCOT shall provide a daily notification to the Department reporting each generating unit that has been designated to use the allowance and operated in reliance on the allowances contained in this Order.

In furtherance of the foregoing and, in each case, subject to the exhaustion of all available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions available to support grid reliability:

(i) with respect to any Specified Resource that is an ERCOT Generation Resource or Settlement Only Generator whose operator notifies ERCOT that the unit is unable, or expected to be unable, to produce at its maximum output due to an emission or effluent limit in any federal environmental permit, ERCOT shall ensure that such Specified Resource is only allowed to exceed any such limit during a period for which ERCOT has declared an Energy Emergency Alert (EEA) Level 2 or Level 3. This incremental amount of restricted capacity would be offered at a price no lower than $1,500/MWh. Once ERCOT declares that such an EEA Level 2 or Level 3 event has ended, the unit is required to immediately return to operation within its permitted limits; and

(ii) with respect to any Specified Resource that is an ERCOT Generation Resource whose operator notifies ERCOT that the unit is offline or would need to go offline due to an emission or effluent limit in any federal environmental permit, and to which ERCOT has issued a Reliability Unit Commitment (RUC) instruction, the operator may make all of the unit's capacity available to ERCOT for dispatch during a period for which ERCOT has declared an EEA Level 2 or Level 3. This incremental amount of restricted capacity would be offered at a price no lower than $1,500/MWh. Once ERCOT declares that such an EEA Level 2 or Level 3 event has ended, the unit is required to immediately return to operating at a level below the higher of its minimum operating level or the maximum output allowable under the permitted limit.

In the event ERCOT identifies the need to exceed other relevant environmental permitting levels, ERCOT shall specifically identify such permitting levels and DOE will consider ERCOT's request in good faith.

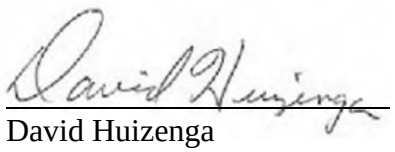
C. All entities must comply with environmental requirements to the maximum extent necessary to operate consistent with the emergency conditions. This Order does not provide relief from an entity's obligations to purchase allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. In the event that ERCOT identifies additional generation units that it deems necessary to operate in excess of federal environmental permitting limits in order to maintain the reliability of the power grid in the ERCOT region when the demand on the ERCOT system exceeds expected energy and reserve requirements, including any such entity to which ERCOT intends to issue a Reliability Unit Commitment (RUC), ERCOT shall provide prompt written notice to the Department of Energy at AskOE@hq.doe.gov identifying in an updated Exhibit A to its Application such additional generation units, the fuel type of such unit, and the anticipated category of environmental impact, at 9:00 Central Standard Time or 21:00 Central Standard Time, whichever follows closest in time to the unit identification by ERCOT to the greatest extent feasible. Such additional generation unit shall be deemed a Specified Resource for the purpose of this Order for the hours prior to the required written notice to the Department, and ERCOT may dispatch such additional generation units, provided that if the Department of Energy notifies ERCOT that its does not approve of such generation unit being designated as a Specified Resource, such generation unit shall not constitute a Specified Resource upon notification from the Department. The Department shall post an updated Order 202-21-1 Resource List as soon as practicable following notification from ERCOT under this paragraph.

E. ERCOT shall provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time. By March 1, 2021, ERCOT shall report all dates between February 14, 2021, and February 19, 2021, on which the Specified Resources were operated, the hours of operation, and exceedance of permitting limits, including sulfur dioxide, nitrogen oxide, mercury, carbon monoxide, and other air pollutants, as well as exceedances of wastewater release limits. ERCOT shall submit a final report by March 31, 2021, with any revisions to the information reported on March 1, 2021. In addition, ERCOT shall provide information to the Department quantifying the net revenue associated with generation in excess of environmental limits accruing to non-RUC units in connection with orders issued by the Department pursuant to Section 202(c) of the Federal Power Act.

F. This Order shall be effective upon its issuance, and shall expire at 11:59 p.m. Central Standard Time Friday, February 19, 2021, with the exception of the reporting requirements in paragraph E. Renewal of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. at 8:51 PM Eastern Standard Time on this 14th day of February, 2021.



David Huizenga
Acting Secretary of Energy

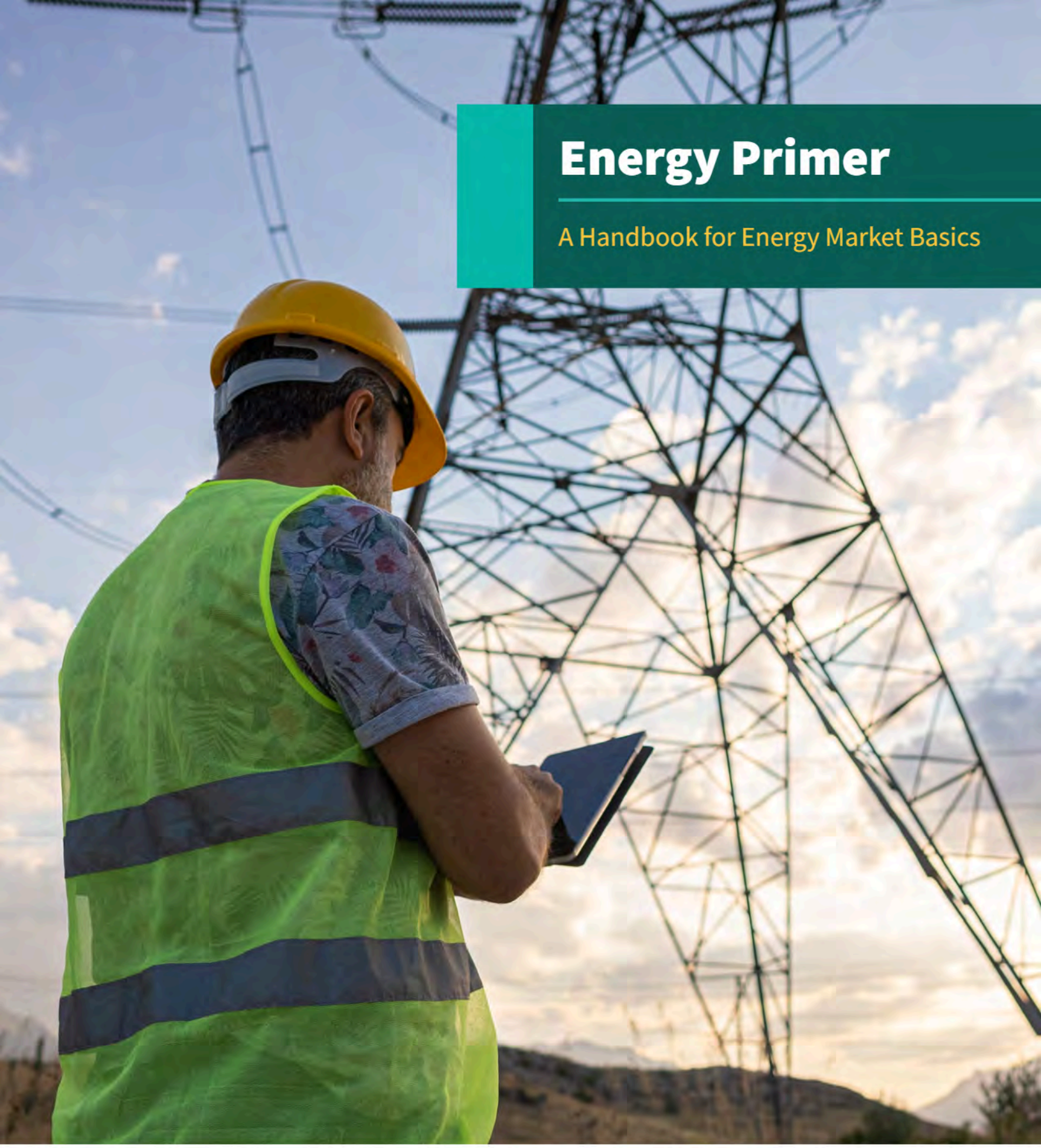
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Exhibit 46

FERC Energy Primer



Energy Primer

A Handbook for Energy Market Basics

FEDERAL ENERGY REGULATORY COMMISSION
Office of Energy Policy and Innovation

Energy Primer

A Handbook for Energy Market Basics

FEDERAL ENERGY REGULATORY COMMISSION
Office of Energy Policy and Innovation
December 2023

This report is a product of the staff of the Federal Energy Regulatory Commission (Commission or FERC). The opinions and views expressed in this paper represent the preliminary analysis of the Commission staff. This report does not necessarily reflect the views of the Commission, its Chairman, or individual Commissioners, and is not binding on the Commission.

ACKNOWLEDGMENT

The Energy Market Primer was originally issued in 2012 and has been updated several times since its first issuance. This update to the Energy Market Primer is the result of the combined efforts of many dedicated individuals throughout the Federal Energy Regulatory Commission (FERC or Commission). The team consisted of individuals from the Commission's Office of Energy Policy and Innovation, Office of Enforcement, Office of Energy Market Regulation, and Office of External Affairs. We specifically wanted to recognize the primary contributors to each chapter.

Chapter 1: Wholesale Natural Gas Markets – Eric Primosch

Chapter 2: Wholesale Electricity Markets – Patricia Schaub

Chapter 3: Gas-Electric Interdependency – Thomas Pinkston

Chapter 4: U.S. Crude Oil and Petroleum Products Markets – Eric Primosch

Chapter 5: Trading and Capital Markets – Astrid Rapp and Gareth Jones

Chapter 6: Market Manipulation – Thomas Olson

IN MEMORIAM



Lance Hinrichs

Federal Energy Regulatory Commission
Office of Energy Policy and Innovation

Lance was instrumental in the creation and publication of the Energy Market Primer. He will forever be remembered as a dedicated public servant whose knowledge of energy markets was unsurpassed.



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INTRODUCTION

Natural gas, electricity, and crude oil are forms of energy that are of particular interest to the Federal Energy Regulatory Commission (FERC) pursuant to its authority under the Natural Gas Act, the Federal Power Act, and the Interstate Commerce Act. This primer explores the workings of the wholesale markets for these forms of energy, as well as energy-related financial markets.

Energy markets consist of both physical and financial elements. The physical markets contain the natural resources, infrastructure, institutions and market participants involved in producing energy and delivering it to consumers. The financial markets include the buying and selling of financial instruments that derive value from the price of the physical commodity. These financial markets have their own set of market structures and institutions, market participants, and traded products which have their own drivers of supply and demand. In general, physical and financial markets can be distinguished by the products and by the intentions of the market participants involved.

Much of the wholesale natural gas and electric power industry in the United States trades competitively, while some markets and their prices are established through administrative processes based on the cost of providing service. In competitive markets, prices are largely driven by the economic concepts of supply and demand. Underlying the supply and demand for energy are physical fundamentals - the physical realities of how markets produce and deliver energy to consumers and how they form prices. These physical fundamentals will be covered in Chapter 1 (Wholesale Natural Gas Markets), Chapter 2 (Wholesale Electricity Markets), and Chapter 4 (U.S. Crude Oil and Petroleum Products Markets).

The significant shift in the U.S. fuel mix has heightened the importance over the past decade of the interdependence of the natural gas and electric systems. Given the importance of natural gas in electricity generation, integration of market operations between the natural gas and electricity industries is critical. The primer provides an overview of natural gas and electric system interdependencies in Chapter 3, Gas-Electric Interdependency.

Market participants buy and sell energy based financial contracts for a number of reasons. Physical market participants, such as producers and large consumers, usually use financial contracts to manage price risk and to protect against price volatility. That is, financial contracts can serve as a tool for managing risk akin to insurance. Other market participants use the energy markets to speculate, or to assume a market risk in hope of profiting from market fluctuations. Additionally, companies turn to the capital markets if they need to raise or invest money. This primer explores the market participants, products, market mechanisms and trading at work for natural gas and electricity in the financial markets in Chapter 5, Financial Markets and Trading.

Where there are markets, there will be those who attempt to manipulate the markets for their own benefit. These practices undermine the market's ability to operate efficiently, reduce other market participants' confidence in the markets and distort market outcomes, including prices. Some of these practices are discussed in Chapter 6, Market Manipulation.

This primer is written to be used either as a traditional text – read front to back – or as a reference guide. Consequently, some material is repeated in different sections and references are provided to other parts of the primer where a concept is addressed in greater detail.

Further information about various aspects of energy markets and FERC regulation can be found at www.ferc.gov; then navigate to the Market Oversight tab. You can find the market oversight pages here: https://www.ferc.gov/market-assessments.







Chapter 2
Wholesale Electricity Markets

WHOLESALE ELECTRICITY MARKETS

Electricity is a physical product – the flow of electrical power. It is a secondary energy source, in that it results from the conversion of other energy forms such as natural gas, coal or uranium, or the energy inherent in wind, sunshine or the flow of water in a river. Electricity is not visible or directly observable, but it can be turned on and off and measured.

Quick Facts: *Measuring Electricity*

A key measure of electricity used in industry is the rate at which it is produced, transferred, or consumed – how much energy per unit of time a generator produces, with the units of electricity called watts. Similar measures are kilowatts (kW) – 1,000 watts, and megawatts (MW) – 1,000 kilowatts. A watt, kilowatt, or megawatt is a unit of power.

The amount of electric energy generated, transmitted, or used over time is measured as the number of watt-hours (also expressed as kilowatt-hours, megawatt-hours, or gigawatt-hours).

The amount of electricity a generator can produce in an hour is its capacity, which is typically noted as megawatts. For example, a generator with a capacity of 100 MW can produce 100 MW in an hour. The amount of power consumed at any location is the demand at that point.



Electricity markets have retail and wholesale components. Retail service involves the sales of electricity to consumers and may involve retail markets; wholesale markets typically involve the sales of electricity among electric utilities and electricity traders before it is eventually sold to consumers. Because the Federal Energy Regulatory Commission (FERC) has jurisdiction over wholesale electric rates and not retail electric rates, this document focuses on wholesale electricity markets, although it does address retail demand and other instances where retail markets strongly influence wholesale markets.

Most wholesale electric markets rely upon competitive markets to set prices, but some prices are based on the service provider's cost of service. For wholesale markets, FERC either authorizes jurisdictional entities to sell at market-based rates or at cost-based rates.

Both market-based and cost-of-service prices are affected by physical factors or conditions that drive electric supply and demand – these factors are known as physical fundamentals. For example, weather affects both supply and demand. Fuel costs, capital costs, transmission capacity and constraints, and the operating characteristics of power plants affect the cost at which supply can be provided. The actual price for power is determined by the interaction of supply and demand. For example, extreme heat can drive up demand and require grid operators to activate less-efficient, more-expensive power plants, and consequently drive prices up.

Electric Power Industry

ELECTRICITY ON DEMAND

In the United States and other developed countries, consumers expect electricity to be available whenever they need it. Electricity use has grown as consumers integrate various devices and amenities such as lighting, refrigerators and computers into their everyday lives. Consumers also expect to pay reasonable prices for the electricity that they use.

Meeting these customer expectations requires substantial effort and activity. While technology continues to develop and advance, electric markets can only store a portion of the electricity required to serve electric loads. Thus, the vast majority of electricity must be produced instantaneously as needed. Further, unlike most other markets, electricity's historically inelastic demand does not move with prices. To provide electricity on demand, electric system operations have to be planned and conducted with that goal in mind. In the absence of significant amounts of storage and price responsive demand, operators must plan and operate power plants and the transmission grid so that demand and supply exactly match, every moment of the day, every day of the year, in every location.

ECONOMIES OF SCALE

Electric power is one of the most capital-intensive industries. Generation, transmission and distribution require significant investment in capital intensive equipment, the costs of which are fixed. Spreading these significant fixed costs over more customers helps bring down the cost that each customer pays.

Thomas Edison's first street lighting project in the 1880s grew to electrifying whole neighborhoods, towns, and cities. Providing service over larger areas allowed utilities to take advantage of economies of scale and the cost per unit of production dropped as power plants grew larger and larger. The companies building these facilities were generally self-contained and not connected to each other. They owned and operated generation, transmission, and distribution facilities and were vertically integrated.

While successful for launching the electric utility industry, this market structure had limitations. The larger generating units were difficult to replace if they experienced unexpected shutdowns. As a result, the utilities held and maintained excess capacity in reserve (reserves) to ensure reliable electric service. These reserves were able to quickly replace electricity lost due to an unexpected shutdown or an unexpected increase in electric loads.

RESERVE SHARING

The solution to high reserve costs was to share reserves with adjacent utilities. Instead of building and maintaining all of the capacity required to provide energy and sufficient reserves, utilities were able to pool their reserves and could buy power from their neighbors in times of need cutting their costs significantly as a result. To facilitate reserve sharing, utilities built interconnecting transmission lines between their transmission systems to deliver electricity in the event of a generator outage or some other system disruption. Today's bulk power grid began as a way to maintain reliable service while lowering costs. The value of reserve-sharing agreements led to the formation of power pools, the forerunners of today's regional transmission organizations.

Coordinating exchanges of energy and reserves also led to closer coordination of other utility functions, such as the process of determining which generating units to use to serve electric loads. Operators want to commit just enough capacity to ensure reliability, but no more than is needed. Over time, this coordination ultimately led to the creation of regional transmission organizations that use markets to determine the set of resources to reliably serve electric loads at least cost. These wholesale electricity markets operate over large regions of the country.

Regional coordination also was spurred by special circumstances, particularly in the West. Large federally owned dams on the Columbia and Colorado river systems generate power from the spring runoff of melting mountain snow. When the reservoirs are full and hydroelectric plants are generating plentiful amounts

of power, there is not enough local demand to use the available supply. Since hydropower was cheaper than any alternative, long distance transmission lines were built to deliver the excess power from the Northwest and Southwest to load centers in California. With these transmission interconnections in place, northwestern utilities found that they could get cheaper power from southern power generation at other times of the year. These seasonal and regional disparities in availability and price introduced a lively bilateral trading market.

In the 1960s, the electric power industry created an informal, voluntary organization of operating staff to aid in coordinating the reliable operation of the bulk electric system. Then, in 1965, the largest power blackout until that time hit the northeastern United States and southeastern Ontario, Canada, affecting 30 million people. The blackout led to the development of the National Electric Reliability Council in 1968, shortly thereafter renamed the North American Electric Reliability Council (NERC), and nine regional reliability councils.[74] Rather than serving as a power pool or other entity for sharing reserves, NERC focused on reliability. In 2006, using authority granted in the Energy Policy Act of 2005 (EPAct 2005), FERC certified NERC as the electric reliability organization for the United States, and reliability standards became mandatory and enforceable.

ECONOMY ENERGY TRADE

Transmission interconnections between adjacent utilities were originally built for the primary purpose of delivering reserves in emergencies. However, this created excess transmission capacity, since these events were rare. The interconnections allowed utilities to trade power, which became profitable when the marginal cost of operating their generation was higher or lower than that of their neighbors. Transmission availability provided opportunities for utilities to save money by buying energy when it was cheaper than generating and selling energy to utilities with higher costs. This is called economy energy trading.

EVOLVING PUBLIC POLICIES

Evolving public policies, regulatory constructs and organizational structures shaped the electric power industry over its history. Five concepts that helped shape the electricity industry and markets are outlined below, and still affect the industry today.

REGULATED MONOPOLIES

In the early years of the industry, investors provided funds and took ownership shares in the power stations and electric distribution systems. These utilities became regulated – typically by state agencies – to overcome concern they were natural monopolies in the areas they served, lacking competition, and to bring stability to a capital-intensive industry. Stability came from granting exclusive service territories (or franchises), transparent financial statements, and the formulaic setting of electricity rates that were subject to regulatory oversight and approval. Over time, many of the utilities issued stock, which gave stockholders a share of the company's ownership, commonly referred to as investor-owned utilities (IOUs). The regulatory model for setting electricity rates was almost exclusively cost of service-based until about 30 years ago. Today, retail electric rate regulation is largely still based on cost-of-service, while wholesale electric rate regulation has become increasingly market-based. State regulators are responsible for approving retail rates, as well as utilities' investments in generation and distribution facilities. Some states eventually developed elaborate integrated resource planning (IRP) processes to determine what facilities should be built.[75]

NOT-FOR-PROFIT UTILITIES

Another approach to serving customers emerged in the form of nonprofit electric providers. In the early years of the industry, electrification started in towns and cities

74 In 2006, the North American Electric Reliability Council changed its name to the North American Electric Reliability Corporation (also referred to as NERC).

75 For additional background and context on the early years of the electrification of the U.S., National Museum of American History, *Powering a Generation of Change, Emergence of Electrical Utilities in America* (2002), http://americanhistory.si.edu/powering/past/h1main.htm.

where utility service was provided by municipal power agencies or city governments. The federal government also stepped in to develop and market electricity from the nation's significant hydroelectric resources. Finally, the Depression-era rural electrification program promoted customer-owned rural electric cooperatives and low-interest government loans. There are currently more than 1,700 municipal and almost 900 cooperative utilities in the United States.

POWER POOLS

Power pools are multilateral arrangements with members ceding operational control over their generating units and transmission facilities to a common operator. Members provide incremental cost data about their units and system status data to the operator. The operator then runs an energy management system that uses the unit cost data to optimize the overall unit commitment and economic dispatch.

The first of the power pools was PJM, which began in 1927 for utilities to share their generating resources. The Electric Reliability Council of Texas (ERCOT) and the Southwest Power Pool (SPP) formed in 1941 to pool resources for the war effort. Later, the New York Power Pool was formed in 1966 and the New England Power Pool in 1971, in response to the 1965 Northeast blackout.

COMPETITION, PART 1: COMPETITIVE GENERATION AND OPEN ACCESS

Environmental policy and initiatives to open the airline and trucking industries to competition helped shape the energy industry in the 1970s. A provision in President Carter's energy plan led to passage of the Public Utility Regulatory Policies Act of 1978 (PURPA), which ushered in the next era.

PURPA established a program implemented by states and overseen by FERC to encourage the use of efficient cogeneration (using the heat from industrial or other processes to generate electricity) and small-scale renewable generation. FERC's role was to issue regulations for the program and certify that qualifying facilities (QFs) met statutory requirements. States administratively set the price to be paid to these generators at the cost the utilities would avoid by purchasing the power rather than generating it themselves. Such prices are referred to as avoided-cost rates.

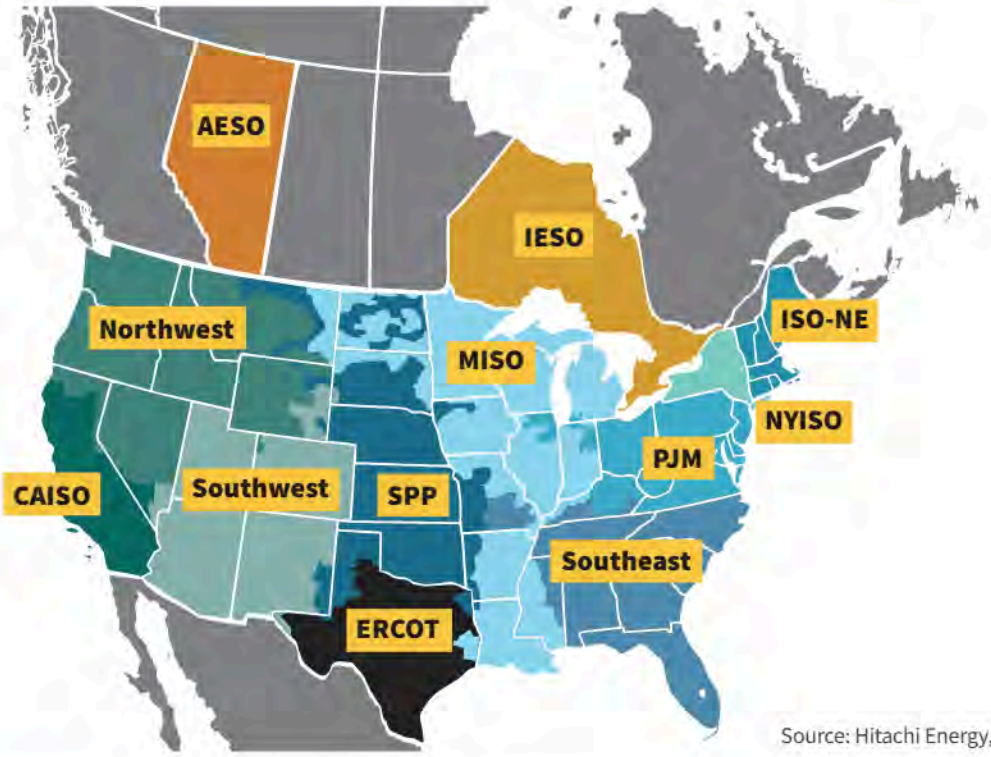
Most states set their avoided-cost rates so low that they got little QF capacity. However, California, Texas, and Massachusetts set relatively generous avoided-cost rates, and were overwhelmed with QF capacity, much of which received prices that turned out to be higher than the actual costs avoided by the purchasing utilities. The rapid growth and size of the QF industry surprised many policymakers and entrepreneurs and got them thinking about the viability of generation independent of regulated monopolies.

Under the original regulated monopoly model, utilities owned and operated the transmission lines with no obligation to allow others to use them. This posed a significant barrier to the development of an independent power industry. FERC started conditioning approval in merger cases on the utility's voluntary provision of open transmission access. The Energy Policy Act of 1992 gave FERC the authority to grant transmission access on request. These approaches to open access resulted in a patchwork of transmission access.

By the mid-1990s, support for opening the transmission grid to all users encouraged FERC to pursue a generic solution. FERC issued Order No. 888 in 1996 and required mandatory open transmission access by all transmitting utilities and a reciprocity provision successfully extended open access to non-jurisdictional entities (municipal, cooperative and federal utilities).

Order No. 889 addressed matters needed to implement open access. The rule established the Internet-based Open Access Same-Time Information System (OASIS) for posting available transmission capacity and reserving transmission capacity. These rules required significant changes to utility control room operations and limited the ability of companies to share transmission-related information with their own power marketing operating units.

Figure 2-1: North American Regional Transmission Organizations, Independent System Operators and Bilateral Regions



Source: Hitachi Energy, Velocity Suite

COMPETITION, PART 2: INTEGRATING MARKETS AND OPERATIONS – ISOS AND RTOS

While the industry had historically traded electricity through bilateral transactions and power pool agreements, Order No. 888 promoted the concept of independent system operators (ISOs). Along with facilitating open access to transmission, an ISO would operate the transmission system independently of wholesale market participants and foster competition for electricity generation. Several groups of transmission owners formed ISOs, some from existing power pools.

In Order No. 2000, FERC encouraged utilities to join regional transmission organizations (RTOs) which, like ISOs, would operate the transmission systems and develop innovative procedures to manage transmission equitably. FERC's proceedings in Order Nos. 888 and 2000, along with the efforts of the states and the industry, led to the voluntary formation of ISOs and RTOs. Each of the ISOs and RTOs subsequently developed full-scale energy and ancillary service markets in which buyers and sellers could bid for or offer generation. Both organizations use bid-based markets to determine economic dispatch. Throughout the subsequent sections of the primer, when referring to the organized RTO and ISO markets generally and collectively, the term RTO/ISO is used.

Major parts of the country operate under more traditional market structures, notably the West (excluding California) and the Southeast. Two-thirds of the nation's electricity load is served in RTO/ISO regions.

Electricity Demand

Americans consume electricity for an ever-increasing range of uses. While consumption has grown over the years, it varies annually based on many influences, such

as weather, economic activity, and other factors. Total generation at utility-scale facilities reached 4,108,303 gigawatt hours in 2021.[76]

Vertically-integrated IOUs, federal entities, municipally owned, and electric cooperatives sell the majority of electric generation to retail consumers. Additionally, some retail consumers generate all or part of the power that they consume. The rest of the electricity ultimately consumed by customers is bought and sold through wholesale electricity markets.

DEMAND CHARACTERISTICS

The amount of electricity consumed (demand) is continuously varying and follows cycles throughout the day and year. Regionally, electric demand may peak in either the summer or the winter. Spring and fall are considered shoulder months, with lower peak demand. Seasonal peaks vary regionally, although the highest levels of power load in almost all regions of the United States occur during summer heat waves, in the late afternoon. However, a minority of regions reach their peak load when the weather is extremely cold. These are primarily areas with significant space-heating requirements and little summer air conditioning load, such as the far northern areas of the United States.

Throughout the year, and in most locations, daily demand typically peaks in the late afternoon, as commercial and domestic activities peak, and in the winter, when lighting needs grow. Electricity use also varies between weekdays and weekends. Commercial and industrial activities are lower on weekends and peoples' noncommercial activities change with their personal schedules. The load on different weekdays can also show distinct usage. For example, Mondays and Fridays, being adjacent to weekends, may have different loads than Tuesday through Thursday. This is particularly true in the summer.

Since supply must rise and fall to provide exactly the amount of electricity customers need, the cost of providing power typically rises as demand grows and falls as demand declines. This is because higher levels of demand require activation of increasingly expensive sources of power generation, and reductions as demand declines. As a result, power prices are typically highest during periods of peak demand.

DEMAND DRIVERS

The amount of electricity demanded is insensitive to prices in the short-term. Electricity is a necessity to most people and businesses. While they may be able to reduce their demand in the short-term – by turning down the thermostat or turning off lights, for example – electricity consumers find it difficult to do without electricity altogether. Further, most customers – especially smaller customers – do not get price signals to which they can respond. A vast majority of residential customers are billed monthly on a preset rate structure. Large industrial customers, on the other hand, may receive real-time price signals.

In the longer-term, options for reducing electricity use include installing insulation and implementing other energy efficiency measures. Larger consumers may also consider building their own generation facilities.

As discussed below, utilities, at the direction of government, have developed demand-response programs, which can provide reduced rates or other compensation to customers who agree to reduce load in periods of electric system stress.

Climate and Weather

Weather is one of the primary factors affecting demand. General climatic trends drive long-term consumption patterns and therefore the infrastructure needed to ensure reliable service.

Weather also can have extreme short-term effects on electricity usage. A sudden cold snap can drive heating use up quickly and a heat wave can push up air conditioning loads. Other, less obvious weather patterns affect demand

76 Derived from EIA, *Electric Power Annual, Table 3.1.A* (released November 8, 2022), www.eia.gov/electricity/annual/html/epa_03_01_a.html.

– rain and wind, for example, may result in sudden cooling, affecting heating or air conditioning usage.

Economic Activity

The overall level of economic activity affects power demand. During periods of robust activity, loads increase. Conversely, loads drop during recessions. These changes are most evident in the industrial sector, where businesses and plants may close, downsize, or eliminate factory shifts. In addition to reducing overall demand, these changes affect the pattern of demand; for example, a factory may eliminate a night shift, cutting off-peak use but continue its use of power during peak hours. In some cases, these effects can be significant. For example, the COVID-19 pandemic changed how consumers used electricity as communities and companies implemented social distancing and stay-at-home measures to combat the spread of COVID-19 in the spring of 2020. Electricity demand shifted from commercial and industrial uses to residential consumption. Overall, electricity demand in the U.S. dropped about 4% in 2020, as commercial and industrial demand dropped 6% and 8%, respectively, and residential demand rose 1%.[77]

Energy Policies and Regulations

State regulatory agencies, such as public utility commissions, oversee retail electric rates and set policies affecting retail customer service. Some states allow utilities to offer retail rate structures that enable customers to receive more accurate price signals. They include, among other things, rates that vary with the time of day and the cost of providing electricity.

Efforts to reduce overall demand by improving energy efficiency are also supported by governmental and utility programs. These include rebates for the purchase of energy efficient appliances and home improvements, as well as capacity market payments for load reductions, also known as demand response, that are made available in certain markets.

Quick Facts: *Heating and Cooling Degree Days*

In the United States, engineers developed the concept of heating and cooling degree days to measure the effects of temperature on demand. Average daily temperatures are compared to a 65°F standard - those in excess of 65° yield cooling degree days; those below 65° yield heating degree days. For example, a day with an average temperature of 66° would yield one cooling degree day.



Retail Customer Mix

Most electric utilities serve three distinct classes of customers: residential, commercial, and industrial. Each class uses electricity differently, resulting in a differing load profile, or the amount of energy each customer class uses throughout the day. If a consumer uses electricity consistently throughout the day and seasons, the load shape is flat. Another consumer may use more at some times than others. More variable demand is typically more expensive to serve, especially if the peak occurs at the same time as other customers' use peaks. Consequently, the mix of customer types affects a region's overall demand and costs.

77 EIA, *Short-Term Annual Outlook*, at 3 (January 2020).

Residential consumers form one of the top two customer segments in the United States at approximately 39 percent of electricity demand in 2021. Residential consumers use electricity for air conditioning, refrigerators, space and water heating, lighting, washers and dryers, computers, televisions, and other appliances. Prices for residential service are typically highest, reflecting both residential customers' load shape and their service from lower-voltage distribution facilities, meaning that more power lines and related assets are needed to provide service to them.

Commercial use, the next largest customer segment, represented approximately 35 percent of electricity demand in 2021.[78] This customer segment includes office buildings, hotels and motels, restaurants, street lighting, retail stores, wholesale businesses, and medical, religious, educational, and social facilities. More than half of commercial consumers' electricity use is for heating and lighting.

Industrial consumers use about 26 percent of the nation's electricity.[79] This customer segment includes manufacturing, construction, mining, agriculture and forestry operations. Industrial customers often see the lowest rates, reflecting their relatively flat load profile and their ability to take service at higher voltage levels.

Transportation demand for electricity stems primarily from trains and urban transportation systems. This is less than 1 percent of total electricity demand.[80] However, state and federal policies that advance electrification of the transportation fleet are expected to increase electric load growth in the near future.

LOAD FORECASTING

Demand is constantly changing, which challenges grid operators and suppliers who are responsible for ensuring that supply will meet demand at all times. Consequently, they expend considerable resources to forecast demand.

Load forecasting uses mathematical models to predict demand across a region, such as a utility service territory or an RTO/ISO footprint. Forecasts can be divided into three categories: short-term forecasts, which range from one hour to one week ahead; medium-term forecasts, usually a week to a year ahead; and long-term forecasts, which are longer than a year. It is possible to predict the next-day load with an accuracy of approximately one to three percent of what will actually happen. The accuracy of these forecasts is limited by the accuracy of the weather forecasts used in their preparation and the uncertainties of human behavior.

The forecasts for different time horizons are important for different operations within a utility company. Short-term load forecasting can help to estimate transmission system power flows and to make decisions that can prevent overloading of transmission systems. Timely implementation of such decisions leads to the improvement of network reliability and to reduced occurrences of equipment failures and blackouts. Forecasted weather parameters are the most important factors in short-term load forecasts, with temperature and humidity as the most commonly used load predictors.

The medium- and long-term forecasts take into account historical load and weather data, the number of customers in different customer classes, appliances used in the area and their characteristics, economic and demographic data, and other factors. For the next-year peak forecast, it is possible to provide an estimated peak load based on historical loads and weather conditions. Long-term forecasts extending 10 to 20 years into the future are used for system infrastructure planning and are meant to ensure that there are sufficient resources available to meet the needs of the expected future peak demand.

Forecasts are necessary for the variety of actions that must occur to ensure that sufficient supply is available in the immediate and long term. These include the

78 Derived from EIA, *Electric Power Annual, Table 2.5* (November 7, 2022), www.eia.gov/electricity/annual/html/epa_02_05.html.

79 *Id.*

80 *Id.*

planning of long-term infrastructure, purchasing fuel and other supplies, and ensuring adequate staffing of specific personnel. Load forecasts are also extremely important for suppliers, financial institutions, and other participants in electric energy generation, transmission, distribution, and trading. Missed forecasts, when actual demand differs significantly from the forecast, can cause wholesale prices to be significantly higher or lower than they otherwise might have been.

DEMAND RESPONSE

Electricity demand is generally insensitive to price, meaning that demand does not typically fall when prices rise. This occurs for several reasons, including that most end-use consumers of electricity are not exposed to real-time electricity prices. However, some utilities and grid operators have developed ways to stimulate a response from consumers through demand-response programs.

Demand response is the reduction in consumption of electricity by customers from their expected consumption levels, in response to either reliability needs or price signals. Customers will forego power use for short periods, shift some energy use from peak periods to other times, or use on-site generation in response to price signals or incentives for load reduction. The signals to respond to electric power system needs or high market prices may come from a utility or other load-serving entity, an RTO/ISO, or an independent provider of demand response. Both retail and wholesale entities administer these programs. Demand response has the potential to lower system-wide power costs and assist in maintaining reliability. It can also mitigate system stress and allow operators to resolve shortages, avoid operating inefficient power plants, or relieve transmission congestion. There can also be environmental benefits, such as lower levels of power plant-related emissions that result from not operating peaking units.

Measuring and verifying the amount of reduced consumption during a demand response activation requires development of consumers' baseline usage, against which their actual use is measured.

Demand-Response Programs

Programs generally fall into three categories: curtailing, shifting, or on-site generation.

Curtailing, or forgoing, involves reducing power use (load) during times of high prices or threats to reliability without making up the use later. For example, residential customers might turn off lights or raise thermostats during hot weather. Commercial facilities may turn off office equipment, lower building lighting or change thermostat settings by a few degrees.

Shifting involves moving or rescheduling high energy-use activities in response to high prices or demand response program events to off-peak periods – evenings, nights, or weekends. Industrial customers might reschedule batch production processes to evening hours or the next day. Commercial establishments may delay high-energy operations. Residential customers may wait until evening or night to use high energy consuming appliances, such as clothes dryers or dishwashers. In shifting, the lost amenity or service is made up at a subsequent time.

On-site generation is when customers respond by turning on an on-site or backup emergency generator to supply some or all of their electricity needs. Although these customers may have little or no interruption to their electrical usage, their net load and requirements from the power system are reduced. The ability to use on-site generation is most common for institutional customers, such as hospitals, large schools, or data centers.

Demand response programs can be further distinguished by whether they are controlled by the system operator (dispatchable) or the customer (non-dispatchable). Dispatchable demand response refers to programs where the system operator can direct the customer to reduce its energy use, such as direct load control of residential appliances or directed reductions to industrial customers. Dispatchable demand response programs can be used for both reliability and economic reasons. Non-dispatchable demand response lets the retail customer decide whether and when to reduce

consumption in response to the price of power. This includes time-sensitive pricing programs that are based on rates that charge higher prices during high-demand hours and lower prices at other times.

As a result of technological innovations and policy directions, new types and applications of demand response are emerging that encompass the use of smart appliances that respond in near real-time to price or other signals. These models may allow customers to respond more easily, as they require little customer monitoring or interaction.

Retail Demand Response Programs

Utilities and third-party aggregators offer a variety of demand response programs that include time-based rates and interruptible contracts. Also, some states mandate energy efficiency resource standards that include peak load reduction targets.

Time-based rates include time-of-use rates and dynamic pricing. Time-based rates depend on advanced meters at customer premises that can record usage over short increments, typically groupings of hours or individual hours. In time-of-use programs, customers are charged different prices at different times of the day, with hours on or near peak demand costing more than off-peak hours. Dynamic pricing is a category of programs where rates change frequently to better reflect system costs. The practice of adjusting prices as costs change provides an incentive for consumers to shift load to other periods or to reduce peak load. One form of dynamic pricing is termed real-time pricing. In these programs, customers are charged prices reflecting the immediate cost of power. Industrial or very large commercial customers are the most likely to choose real-time tariffs.

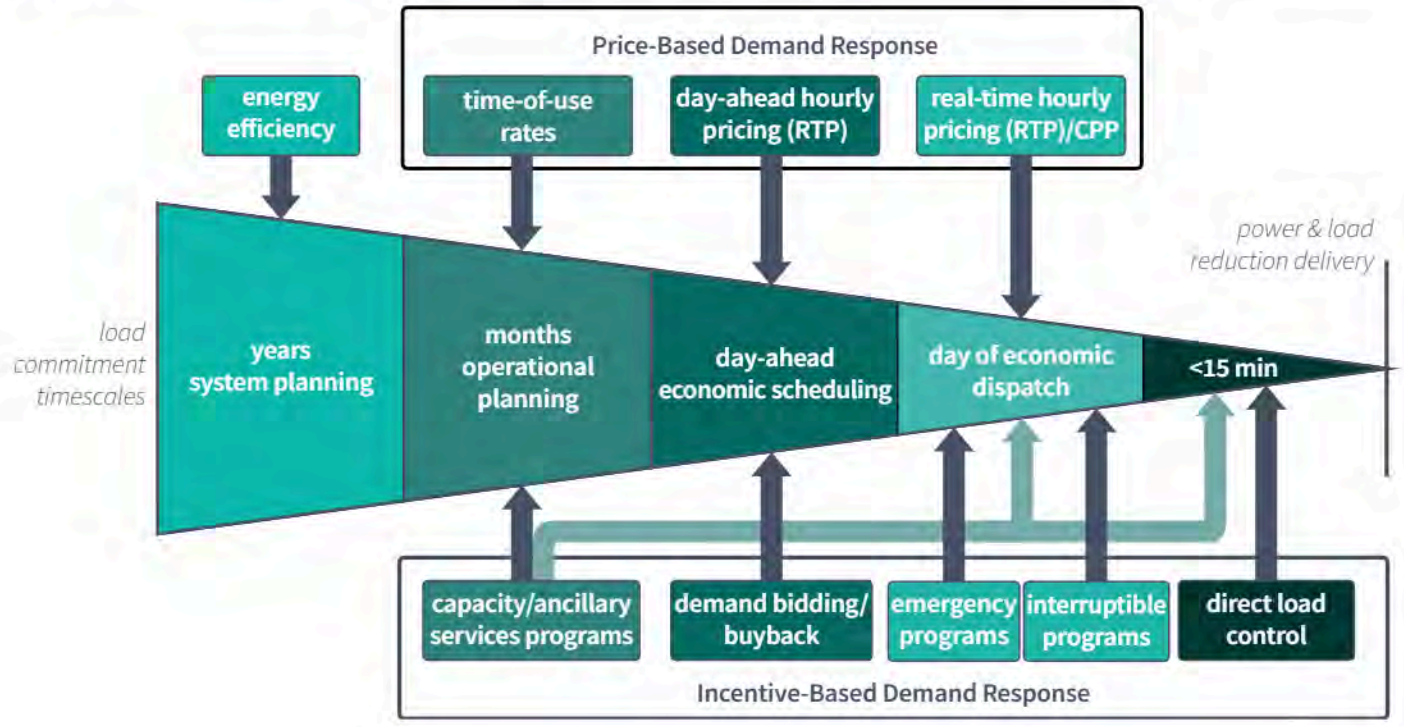
Another form of dynamic pricing is critical peak pricing. These programs use real-time prices at times of extreme system peak but are restricted to a limited number of hours annually. They feature higher prices than time-of-use prices during the critical peak. Consumers do not know in advance when a critical peak might be called. Critical peak programs for residential customers typically use rebates as an incentive to participate in the program, but customers take the risk of paying higher prices or reducing load during critical peak periods. These programs seek to have customers respond to price signals, as opposed to penalizing them, if they do not lower their use in the critical peak hours.

Interruptible contracts are used by utilities to control load and address potential reliability issues, such as reducing stress on the electric system during heat waves. The two primary forms of this category of demand response are direct load control and interruptible rates. Direct load control entails the utility curtailing a portion of customer load as described above. Under interruptible rates, customers agree to turn off equipment or switch their energy supply to an on-site generator.

Energy efficiency resource standards exist in 25 states, while five states and the District of Columbia. have energy efficiency goals.[81] The standards typically require utilities to achieve electric energy savings, and many include peak load reduction targets. These mandates provide incentives for utilities to reduce customers' energy consumption and include mechanisms that decouple profits from the amount of electricity sold or performance bonuses for utilities that meet or exceed reduction targets.

81 DSIRE, N.C. Clean Energy Technology Center, *Energy Efficiency Resource Standards (and Goals)* at 1 (September 2021), https://ncsolarcen-prod.s3.amazonaws.com/wp-content/uploads/2021/09/Energy-Efficiency-Resource-Standards_Sept-2021.pdf.

Figure 2-2: Demand Response and Energy Efficiency in Electric System Planning and Operations



Source: U.S. Department of Energy[82]

Wholesale Market Demand Response Programs

On the wholesale level, market operators have some programs that dispatch the demand response resources. Other demand response programs are dispatched by the utilities or aggregators that sponsor the programs, rather than the market operator. Note that with most retail demand response programs, which can also aid wholesale markets, market operators may not be able to invoke them or even see the specific amount of response that occurs.

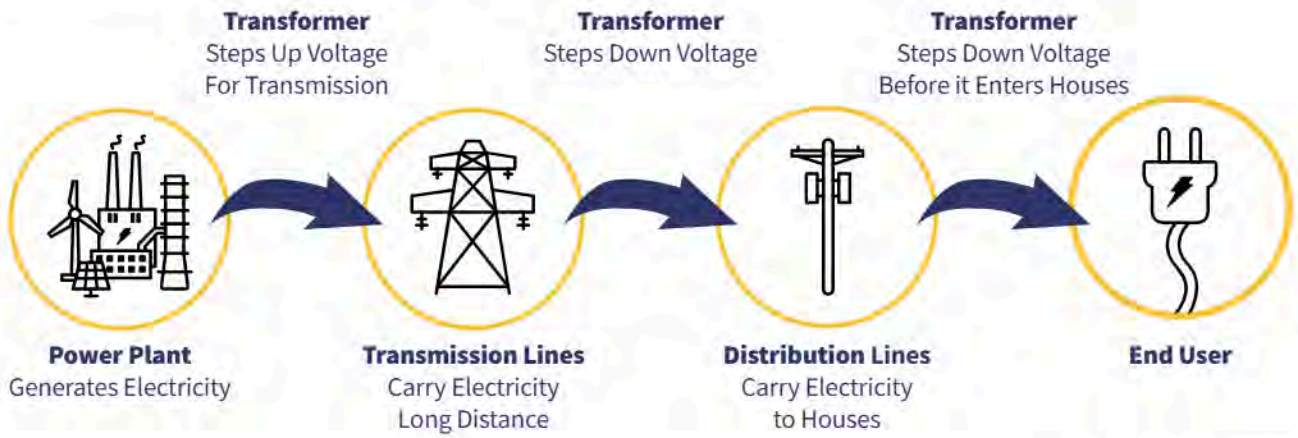
Demand response participation in RTO/ISOs has been encouraged in U.S. national energy policy and by various FERC orders.[83] Overall, approximately 30.8 GW of demand response participated in RTOs/ISOs in 2020.[84] These resources primarily participate in RTO/ISOs as capacity resources and receive advance reservation payments in return for their commitment to participate when called upon or activated. Additionally, demand resources may offer into the RTO/ISO day-ahead markets, specifying the hours, number of MWs and price at which they are willing to curtail.

82 U.S. Department of Energy, *Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them: A Report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005*, at 15, (2006), https://www.energy.gov/oe/articles/benefits-demand-response-electricity-markets-and-recommendations-achieving-them-report.

83 EPAct 2005 included policy encouraging time-based pricing and other forms of demand response and the elimination of barriers to demand response participation in the energy, capacity, and ancillary services markets. Examples of FERC orders include Order No. 719, 128¶61,059, (July 16, 2009); Order No. 745, 134¶61,187 (March 15, 2011); and Order No. 2222, 174¶61,197, (March 18, 2021).

84 *See* FERC, *Assessment of Demand Response and Advanced Metering Staff Report*, at 3 (December 2021), https://www.ferc.gov/media/2021-assessment-demand-response-and-advanced-metering.

Figure 2-3: Electricity Supply and Delivery



Source: The NEED Project[85]

Some of the RTO/ISO demand response comes from individual entities; the rest is accumulated through third-party aggregators, or curtailment service providers, who recruit customers too small to participate on their own, such as schools, commercial chains or groups of residential customers. In aggregating small customers, curtailment service providers have increased customer participation in many wholesale reliability and emergency programs.

Demand Response and Energy Efficiency in Planning and Operations

Different demand response programs can be used at various times to support planning and operations (see Figure 2-2). Energy efficiency programs that reduce baseload or peak demand over the long-term are incorporated into system planning. Dispatchable programs that are quickly implemented and targeted for short-term peak reductions – such as direct load control – lie on the other end of the spectrum and are used in the moment of operation.

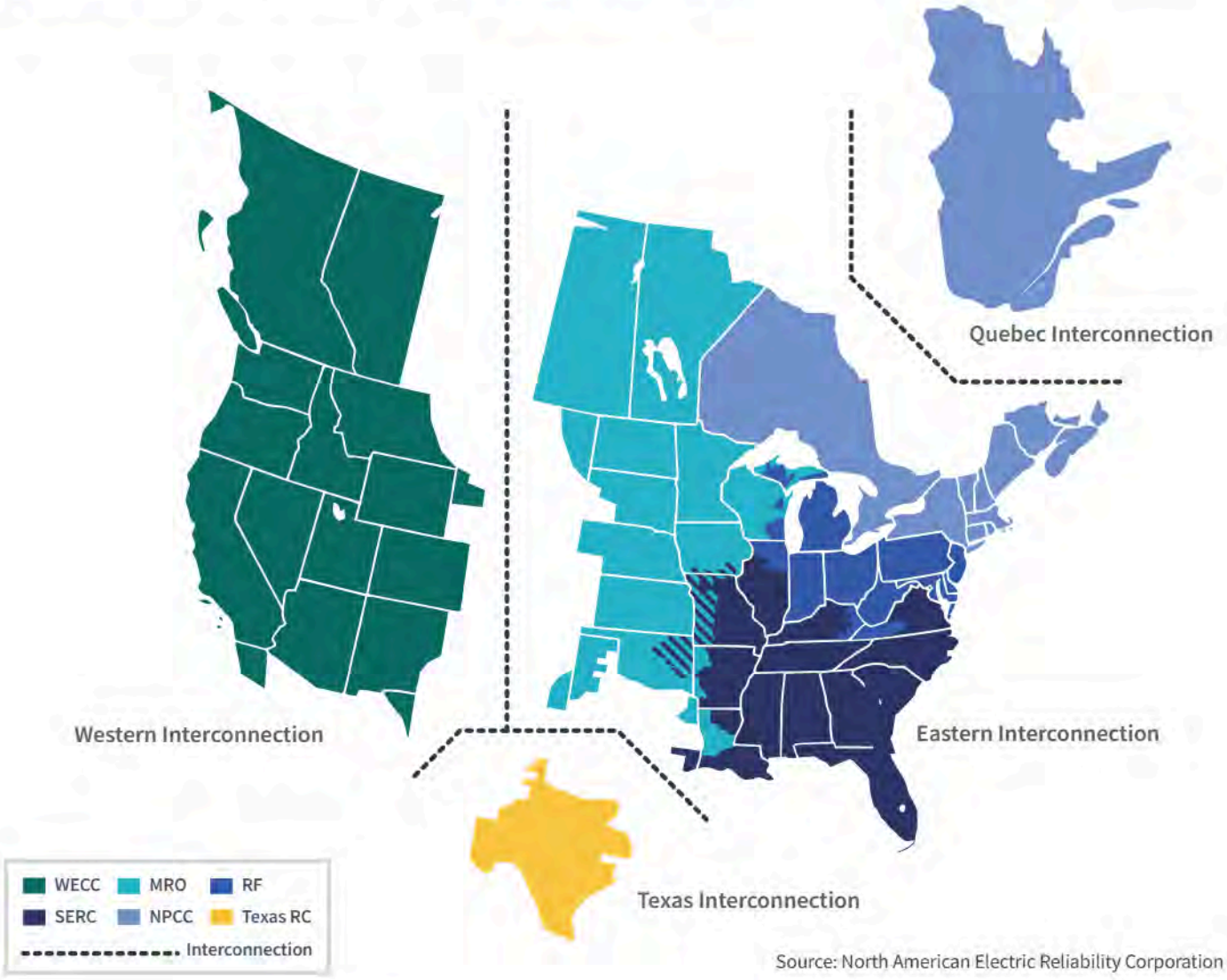
Electricity Supply and Delivery

Unlike many other products, electricity cannot be stored in any appreciable quantity relative to the total consumed across the country each day. Further, electricity is a necessity for most consumers, whose use responds little to price changes. Finally, electric equipment and appliances are tuned to very specific standards of power, measured as voltage and frequency. For example, deviations in voltage can cause devices to operate poorly or may even damage them. Consequently, the supply side of the electricity market must provide and deliver exactly the amount of power customers want at all times, at all locations. This requires constant monitoring of the grid and close coordination among industry participants.

Electricity service relies on a complex system of infrastructure that falls into two general categories: generation and delivery services of transmission and distribution. Together, the power generation and high-voltage transmission lines that deliver power to distribution facilities constitute the bulk power system. Transmission and distribution facilities are also referred to as the power grid. These are coordinated, and at times operated by, a grid coordinator.

85 National Energy Education Development Project, *Electricity*, at 56 (2017), http://www.need.org/Files/curriculum/infobook/Elec1S.pdf.

Figure 2-4: North American Electric Reliability Corporation Regions



Source: North American Electric Reliability Corporation

Nationally, the grid is geographically split into three main sections – the Western, Eastern and Texas Interconnections. These sections operate independently and have limited interconnections between them.

The nation, along with Canada and a small part of Mexico, is also divided into regional entities for reliability purposes. The regional reliability entities fall under the purview of North American Electric Reliability Corporations (NERC), which was designated by FERC as the nation's electric reliability organization, and which develops and enforces mandatory reliability standards to better ensure the reliable operation of the nation's bulk-power system (the interconnected transmission grid). The reliability standards, once approved by FERC, must be met by applicable industry participants as designated in each reliability standard. Consequently, the grid is planned and operated to meet these standards.

NERC's regions include:

- Midwest Reliability Organization (MRO)
- Northeast Power Coordinating Council (NPCC)
- Reliability First Corporation (RFC)
- SERC Reliability Corporation (SERC)
- Texas Reliability Entity (TRE)
- Western Electricity Coordinating Council (WECC)

FERC JURISDICTION

Under the Federal Power Act (FPA), FERC regulates the transmission of electric energy in interstate commerce and the sale of electric energy at wholesale in interstate commerce. The FPA requires that every public utility file with FERC all rates and charges for any transmission or sale subject to the jurisdiction of FERC. Under Sections 205 and 206 of the FPA, 16 U.S.C. §§ 824d, 824e, FERC ensures that the rates and charges made, demanded, or received by any public utility for, or in connection with, the transmission or sale of electric energy subject to the jurisdiction of FERC, and all rules and regulations affecting, or pertaining to, such rates or charges are just and reasonable and not unduly preferential or unduly discriminatory.

GENERATION

Power generators are typically categorized by the fuel that they use and subcategorized by their specific operating technology. In 2021, the United States had approximately 1,218 GW of total generating capacity.[86] The majority of power generation is produced from coal, natural gas, nuclear fuels, and renewables.

Power plants each have differing costs and operational characteristics, both of which determine when, where and how plants will be built and operated. Plant costs fall into two general categories: capital investment costs, which are amounts spent to build the plant, and operational costs, the amounts spent to maintain and run the plant. In general, there is a trade-off between these expenses: more capital-intensive plants tend to be cheaper to run – they have lower variable costs – and, conversely, the least capital intensive plants tend to be more expensive to run – they have higher variable cost. For example, nuclear plants produce vast amounts of power at low variable costs but are expensive to build. Conversely, natural gas-fired combustion turbines are far less expensive to build but can be more expensive to run. Grid operators dispatch plants – or call them into service – with the simultaneous goals of providing reliable power at the lowest cost. Because various generation technologies have differing variable costs, plants are dispatched only when they are part of the most economic combination of plants needed to supply the customers on the grid. For plants operating in RTOs/ISOs, this cost is determined by the price that generators offer. In other areas, it is determined by the marginal cost of the available generating plants.

CONVENTIONAL GENERATION

Generation is often described as conventional or renewable (described further in the Renewable Generation section below). Conventional generation typically includes natural gas-, oil-, coal- or nuclear-powered generation.

Natural Gas-Fired Generation

Natural gas power plants consist of three major technologies, each with its distinct set of market advantages and limitations. They are steam boilers, gas turbines and combined cycle generators. Natural gas fuels nearly a third of U.S. electricity generation.

Steam boiler technology is an older design that burns gas in a large boiler furnace to generate steam at both high pressure and high temperature. The steam is then run through a turbine that is attached to a generator, which spins and produces electricity. Typical plant size ranges from 300 MW to 1,000 MW. Because of their size and the limited flexibility that is inherent in the centralized boiler design, these plants require fairly long start-up times to become operational and are limited in their flexibility to produce power output beyond a certain range. Furthermore, these plants are generally not as economical or easy to site as some newer technologies – which explains why few have been built in recent years.

86 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M)* (February 2022), https://www.eia.gov/electricity/data/eia860m/.

Gas turbines (GT) are small, quick-start units similar to an aircraft jet engine. These plants are also called simple cycle turbines or combustion turbines (CT). GTs are relatively inexpensive to build but are expensive to operate because they are relatively inefficient, providing low power output for the amount of gas burned, and have high maintenance costs. They are not designed to run on a continuous basis and are used to serve the highest demand during peak periods, such as hot summer afternoons. GTs also run when there are system-wide shortages, such as when a power line or generator trips offline. GTs typically have a short operational life due to the wear-and-tear caused by cycling. The typical capacity of a GT is 10-50 MW, and they are usually installed in banks of multiple units.

Combined cycle power plants (CCPPs) are a hybrid of the GT and steam boiler technologies. Specifically, this design incorporates a gas-combustion turbine unit along with an associated generator, and a heat recovery steam generator along with its own steam turbine. The result is a highly efficient power plant. They produce negligible amounts of SO2, and particulate emissions and their NOx and CO2 emissions are significantly lower than a conventional coal plant. CCPPs, on average, require 80 percent less land than a coal-fired plant, typically 100 acres for a CCPP versus 500 acres for comparable coal plant, and CCPPs also use modest amounts of water compared to other technologies.

Coal-Fired Generation

Coal plants produced approximately 22 percent of the electricity in the United States in 2021.[87] These facilities generate power by creating steam which is used to spin a very large turbine. These plants tend to be used as baseload units, meaning that they run continuously and are not especially flexible in raising or lowering their power output. They have high initial capital costs, with complex designs and operational requirements. However, coal plants have low marginal costs and can produce substantial amounts of power. Most of the coal-fired plants in the United States are located in the Southeast and Midwest.

Oil-Fired Generation

Oil plants generally produce only a small amount of the total electricity generated in the U.S. power markets. These facilities are expensive to run and also emit more pollutants than natural gas plants. They are frequently uneconomic and typically run at low-capacity factors. Like natural gas-fired generators, there are several types of units that burn oil; primarily, these are steam boilers and combustion turbines. Most dual-fuel power plants are located in the eastern half of the United States, especially on the East Coast.[88]

Generally, two types of oil are used for power generation: number 2 and number 6 (bunker) fuel oil. Number 2 is a lighter and cleaner fuel. It is more expensive, but because it produces fewer pollutants when burned, it is better for locations with stringent environmental regulations such as major metropolitan areas. Conversely, number 6 fuel oil is cheaper, but considered dirty because of its higher emissions. It is highly viscous (thick and heavy), and it comes from the bottom of the barrel in the refining process.

Nuclear Generation

Nuclear plants provided roughly 19 percent of the nation's electricity in 2021, when 93 nuclear plants operated in the United States with a total capacity of approximately 100 GW.[89] Like generating units that use coal, nuclear plants tend to be large, baseload units that run continuously. Nuclear plants have high capital and fixed costs, but low variable costs, which includes fuel cost. They typically run at full power for 18 or 24 months, which is the duration of a unit's fuel cycle, and are then taken offline for refueling and maintenance. Outages

87 EIA, *Electric Power Annual* (November 7, 2022), *Generation at Utility Scale Facilities*, *Tables 3.1A. and 3.1.B*, (accessed December 2022), www.eia.gov/electricity/annual/html/epa_01_02.html.

88 Derived from Hitachi Energy, Velocity Suite data (Accessed March 28, 2023).

89 EIA, *Form EIA-860* (November 2022), www.eia.gov/electricity/data/eia860/.

typically last from 20 days to significantly longer, depending on the work needed. Of the 92 operating nuclear plants, most reside in the eastern United States. Only six are in the West, four in Texas. Illinois had the largest number of plants at 11, followed by Pennsylvania at eight, and South Carolina at seven.[90]

RENEWABLE GENERATION

Renewable resources use fuels that are naturally replaced, such as wind, solar, hydroelectric and geothermal or which use fuels that are readily replaceable, such as biomass and biogas.

Such generation (generation termed renewable generation or renewables) is an increasingly important part of total U.S. supply, accounting for 29 percent of electric energy produced in 2021.[91] As total generation from all fuels has remained relatively constant in recent years, renewable generation's share has risen, spurred by technological advancements, state policy, and federal tax credits.[92]

Wind and solar capacity have grown faster than other renewable resources in recent years. Wind capacity grew substantially, from approximately 10 GW in 2006 to 193 GW in 2021.[93] Utility-scale solar capacity grew even faster, from approximately 0.1 GW to 61 GW over the same period. [94]

Additions of renewable generation capacity are usually reported in megawatts of nameplate capacity. Actual capability varies from the nameplate for any unit type due to such factors as age, wear, maintenance and ambient conditions. But as renewable resources are often weather-dependent, their capacity factors – the ratio of average generation to the nameplate capacity for a specific period – have been lower (for example, approximately 30 percent), depending on the technology type, than for fossil-fuel generation. Grid operators pay close attention to the difference between nameplate and capacity factor values when they evaluate capacity available to cover expected load, however, capacity factors have risen with technological innovation and improved manufacturing processes.

Wind

Wind generation is among the fastest-growing renewable resource, in part due to cost declines and technology improvements, as well as receipt of federal tax credits. Increases in average hub heights and rotor diameters have increased average wind turbine capacity. Because the best wind resources are often located far from load centers, obtaining sufficient transmission presents a challenge to delivering wind output. Other market challenges for future wind development include its variable output, which is often inversely correlated to demand (seasonally and daily); system operators' limited ability to dispatch wind resources to meet load increases; difficulties related to accurately forecasting its ramping; and the need for companion generation (usually fossil-fueled) or energy storage to be available to balance wind generation when the wind is not blowing.

Solar

Solar generation transforms sunlight into electricity using one of two technologies: photovoltaic (PV) or concentrating solar power (CSP). PV modules, or panels, transform sunlight directly into power using cells made of silicon or thin-film materials. They can be installed on roofs of buildings or at ground-level PV farms. CSP plants use a two-step process to transform the sun's energy. First, mirrors direct sunlight towards a receiver that captures

90 EIA, *Form EIA-860M* (February 2023), www.eia.gov/electricity/data/eia860M/.

91 Derived from EIA, *Electricity Annual* (September 2022), www.eia.gov/electricity/annual/html/epa_01_01.html.

92 Lawrence Berkeley National Lab, *U.S. State Renewables Portfolio and Clean Electricity Standards: 2023 Status Update* (June 2023), https://eta-publications.lbl.gov/sites/default/files/lbnl_rps_ces_status_report_2023_edition.pdf.

93 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M)* (February 2022), https://www.eia.gov/electricity/data/eia860m/.

94 *Id.*

the heat. CSP then employs a thermal process to create steam, driving an engine or turbine to produce electricity. CSP plants, which are dispatchable, can include low-cost energy storage that extends their availability later in peak hours. PV growth has increased greatly as a result of policy incentives and cost declines. Total PV generation for 2021 was 161.5 GW, with approximately two-thirds of that generation coming from utility-scale facilities and one-third from small-scale generation.[95]

By the end of 2021, 1.5 GW of CSP was operational – a decline from 2017 when CSP capacity was 1.8 GW.[96] Total CSP capacity is significantly lower than PV owing to PV's lower costs.[97] Seven western and southwestern states have extensive CSP potential: Utah, New Mexico, Arizona, Nevada, Texas, California and Colorado.[98] Developing that potential will require overcoming challenges of cost, siting, transmission, and the need for extensive water supplies to clean mirrors.

Hydroelectric

Hydroelectric generation is powered by the kinetic energy of falling water that drives turbine generators, which convert the energy into electricity. There are two types of hydroelectric projects: conventional and pumped storage. Conventional projects, which use a dam in a waterway, can operate in a run-of-river mode, in which water outflow from the project approximates inflow, or in a peaking mode, in which the reservoir is mostly drained to generate power during peak periods when energy is more valuable. Pumped storage projects use bodies of water at two different elevations. Water is pumped into elevated storage reservoirs during off-peak periods when pumping energy is cheaper; the water is then used to generate power during peak periods as it flows back to the lower elevation reservoir. In 2021, total U.S. hydro-electric capacity (including conventional and pumped-storage capacity) reached 246 GW. Conventional hydro-electric capacity was 285.3 GW and pumped storage hydro-electric capacity was 5.1 GW.[99]

Geothermal

Geothermal generation taps into reservoirs of steam and hot water deep beneath the earth's surface to produce power. The majority of the plants are based in California and Nevada. Geothermal potential is determined by thermal conductivity, thickness of sedimentary rock, geothermal gradient, heat flow and surface temperature. Geothermal generation, which stood at 16 GW in 2021, increased from 0.6 GW in 2011, but has decreased as a portion of total renewable output, due to the growth of other renewables. California hosts about 76 percent of geothermal U.S. operating capacity.[100]

Biomass

Biomass generation includes power production from many waste byproducts, such as agricultural residues, landfill gas, municipal solid waste, and wood resources. The largest biomass category is wood waste, burned for heat and power in the lumber, pulp and paper industries. Challenges to biomass production include impacts on food supplies (for example, converting corn into ethanol), conserving natural resources, and minimizing water pollution. In 2021, net utility-scale power generation using biomass fuel sources was 54.3 GWh - composed of 36.5 GWh from wood and wood-derived fuels as well as 17.8 GWh from other biomass sources.[101]

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95 Derived from EIA, *Electric Power Annual, Tables 3.1.A. and 3.1.B* (released November 7, 2022 and accessed December 2022), www.eia.gov/electricity/annual/html/epa_01_02.html.

96 Derived from EIA, See table 4.3 in *Electric Power Annual 2021 and Electric Power Annual 2017*, www.eia.gov/electricity/annual/html/epa_04_03.html and www.eia.gov/electricity/annual/archive/pdf/03482017.pdf.

97 *See* National Renewable Energy Laboratory, *Annual Technology Baseline* (July 2018), https://atb.nrel.gov/electricity/2018/summary.html

98 EIA, *Form EIA-860*, (September 13, 2018), https://www.eia.gov/electricity/data/eia860/.

99 Derived from EIA, *Electric Power Annual* (November 7, 2022), *Generation at Utility Scale Facilities, Tables 3.1.A and 3.1.B* (accessed December 2022), www.eia.gov/electricity/annual/html/epa_01_02.html.

100 Derived from EIA, *Form EIA-860* (accessed November 2017), https://www.eia.gov/electricity/data/eia860/.

101 *Id.*

Biogas

Biogas energy is created through the anaerobic (without oxygen) bacterial decomposition of biodegradable waste, which is turned into a gas containing 60-70 percent methane. Biogas recovery is typically installed at farms and used to run farm operations and reduce methane emissions from natural manure decomposition.

Renewable Energy Policies

Renewable generation development is frequently tied to policies promoting their use, which include tax credits, low-cost loans, rebates and production incentives. Federal funding of research and development has played an important role in lowering the costs or reducing the time it takes for renewable technologies to become commercially viable.

Congress has provided tax incentives to spur renewable resource investments. Originally enacted in 1992, federal production tax credits (PTC) are available for wind, biomass, geothermal, and other forms of renewable generation based on a facility's production. An inflation-adjusted credit, the PTC generally has a duration of 10 years from the date the facility goes online. The PTC has been revised several times, most recently in August 2022 under the Inflation Reduction Act, which extended the PTC for projects that begin construction before 2025, including solar projects that had previously been excluded from the PTC program.[102] After 2024, the PTC becomes technology neutral and emission based, and phases out starting in 2032, or when the U.S. electricity sector emissions are 75% below 2022 levels. If projects over 1 MW meet certain labor requirements, their PTC is 2.6 c/kWh; if the projects do not meet the labor requirements, the PTC would be 0.3 c/kWh. A further 10% adder on the PTC and ITC can be obtained if a project uses U.S. steel and roughly half the of manufactured components (as measured by cost) are sourced in the United States.

Another form of tax credit for renewables, including solar and other types of projects, has been a federal investment tax credit (ITC). The ITC has generally been set at 30 percent of a project's equipment and construction costs. The Inflation Reduction Act also revised the ITC, with the same terms as for the PTC. Projects meeting labor requirements may receive a 30% ITC, otherwise the ITC drops to 6%. Projects may also receive a 10% increase in the ITC if they use U.S. components, as described for the PTC.

State renewable portfolio standards (RPS) and renewable energy standards (RES) have been significant drivers in the growth of investment in renewable generation. An RPS requires a certain percentage of energy sales measured by megawatt-hours (MWh) to come from renewable resources. Percentages usually increase incrementally from a base year to an ultimate target. Currently, 30 states plus Washington, D.C., have an RPS with financial penalties for non-achievement.[103] As utilities and independent developers build more renewable-powered generation, the markets in which they participate continue to address the integration of renewable output into their day-ahead and real-time operations, and incorporate the expected growth of renewable generation in their long-term transmission-planning processes.

Renewable energy certificates (RECs) allow state regulators to track compliance with mandatory RPS targets or verify progress in voluntary state renewable programs. They also allow compliance entities to purchase credits – subject to state-imposed limits on amount and price – if they have not generated or bought enough renewable energy to meet their annual requirements.

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102 Congress.gov, *H.R. 5376-Inflation Reduction Act of 2022*, (became law August 4, 2022) https://www.congress.gov/bill/117th-congress/house-bill/5376/text.

103 Barbose, Galen. Lawrence Berkeley National Laboratory, *U.S. Renewables Portfolio Standards: 2021 Status Update: Early Release* (February 2021), https://eta-publications.lbl.gov/sites/default/files/rps_status_update-2021_early_release.pdf.

ELECTRIC STORAGE

Historically, utility-scale storage of electricity for later use had been limited to pumped-hydro storage facilities. Recent advances in technology have made other types of electric storage resources, including batteries and flywheels, more economically feasible. The lower costs and improved capabilities of electric storage, along with favorable state and federal policies, increased penetration of variable energy resources, and a continued focus on grid reliability have helped spur the development of electric storage resources.[104]

As of 2021, the combined capacities of utility-scale electric storage and battery storage represented less than 2 percent of total generating capacity in the United States.[105] The majority of storage capacity consists of pumped-hydro storage (21 GW in 2021), which has grown very slowly. Battery storage capacity, in contrast, has grown from 3 MW in 2016 to 4,482 MW in 2021.[106] EIA projects that total U.S. battery storage capacity could reach 30 GW by 2025.[107]

Electric storage projects are increasingly available to help balance supply and demand particularly during periods of high demand or excess supply. These resources can charge during periods of low demand or excess generation, when electricity is less expensive, and discharge when demand is high and electricity is more expensive. Batteries, flywheels, and other fast-acting electric storage technologies can also provide ancillary services which help maintain grid reliability. The vast majority of battery storage capacity in the electricity markets is used to provide ancillary services or capacity, because these applications provide the most revenue for storage owners.[108]

Some states have passed legislation to incentivize investment in storage projects. In 2013, California adopted targets for utilities to procure 1,325 MW of energy storage capacity by 2024 and subsequently increased the capacity requirement target and compressed the timeline for reaching that target.[109] As of May 2021, five states besides California also set energy storage requirements or targets: Oregon, Massachusetts, New York, New Jersey and Virginia. Additionally, some states which do not have formal energy storage requirements offer financial incentives such as grants and tax incentives, while others have begun requiring utilities to include storage in integrated resource plans.

DISTRIBUTED ENERGY RESOURCES

In Order No. 2222, the Commission defined Distributed Energy Resources (DERs) as any resource located on the distribution system, any subsystem thereof or behind a meter. These resources may include, but are not limited to, electric storage resources, distributed generation, demand response, energy efficiency, thermal storage, and electric vehicles and their supply equipment.[110] In most instances, these resources are located close to the

104 FERC has issued various orders to help remove barriers to the participation of electric storage resources in FERC-jurisdictional markets. *See, Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators, Order No. 841, 162 FERC ¶61,127 (2018); Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators, Order No. 2222*, 172 FERC ¶ 61,247 (2020).

105 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M)* (February 2022), https://www.eia.gov/electricity/data/eia860m/.

106 *Id.*

107 EIA, *U.S. battery storage capacity will increase significantly by 2025* (December 8, 2022), https://www.eia.gov/todayinenergy/detail.php?id=54939#:~:text=As%20of%20October%202022%2C%207.8%20GW%20of%20utility-scale,add%20another%2020.8%20GW%20of%20battery%20storage%20capacity.

108 EIA, *U.S. Battery Storage Market Trends*, 13-15 (August 2021), https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage_2021.pdf.

109 California Public Utilities Commission, *Energy Storage* (accessed December 1, 2022), www.cpuc.ca.gov/industries-and-topics/electrical-energy/energy-storage.

110 Order No. 2222, 172¶61,247, (September 17, 2020), at 4.

end user of power. While individual installations of DER tend to have capacities much smaller than that of central station power plants (for example DER installations may range from a fraction of a kW to systems producing less than 10 MW), the overall quantity of DER installations has grown tremendously, particularly in states with beneficial policies toward DERs.

One such policy is known as net metering, which is a system in which DERs are connected behind the meter to a distribution system and any surplus power is transferred onto the grid, allowing customers to offset the cost of power drawn from a distribution utility. Such surplus flow typically occurs during periods when the DER's production outstrips the customer's total demand. Under one measure of DER, as tracked by EIA, total net-metered capacity grew by approximately 277 percent between 2014 and 2020, from approximately 7.5 GW of capacity to 28.3 GW. The bulk of this capacity was solar PV, which made up 94 percent of net-metered capacity in 2020, with 62 percent of that capacity owned by residential customers.[111] In some cases, surplus power from a large DER or a set of net metered DERs may flow onto the transmission system.

TRANSMISSION

The alternating current (AC) power grid operates like an interconnected web, where, with a few exceptions, the flow of power is not specifically controlled by the operators on a line-by-line basis. Instead, power flows from sources of generation to consumers across any number of lines simultaneously, following the path of least resistance. There are also a limited number of direct current (DC) lines, which are set up as specific paths with definite beginning and end points for scheduling and moving power. These lines are controllable by operators and have other characteristics that make them attractive to grid planners and operators, such as providing greater grid stability and lower line losses. However, DC lines cost significantly more than AC lines to construct. Consequently, DC lines are typically built for certain specialized applications such as the movement of large amounts of power over long distances, for example the Pacific Intertie, which extends between the Northwest and California.

Transmission lines provide a certain amount of resistance to the flow of power as electricity travels through them. This resistance is not unlike the wind resistance that a car must overcome as it travels along a highway. The resistance in power lines creates losses: the amount of power injected into a power line diminishes as it travels through the line. The amount of these losses is contingent on many factors including the voltage of the transmission facilities.

111 EIA, *Electric Power Annual* (December 2022), (March 2022), www.eia.gov/electricity/annual/html/epa_04_10.html.

Wholesale Electricity Markets and Trading

Electric markets encompass different organizational structures and different mechanisms for buying and selling power at the wholesale level. Electric systems for delivering power to consumers in the United States are split into two structures: traditional systems and those run by RTO/ISOs. Traditional systems are typically vertically integrated, rely on management to make operational decisions, and sell electricity to retail customers based on their cost of service. In general, RTO/ISOs use their markets to make operational decisions, such as generator dispatch, and to price the resulting electricity. Load-serving entities then buy the power through the RTOs/ISOs for resale to retail customers.

Both traditional systems and RTOs/ISOs conduct certain functions, although they may perform these functions in different ways. These include:

- Ensuring the electric grid operates reliably in a defined geographic footprint
- Balancing supply and demand instantaneously and maintaining sufficient operating reserves
- Dispatching system resources as economically as possible
- Coordinating system dispatch with neighboring balancing authority areas (BAAs)
- Planning for transmission in its footprint
- Coordinating system development with neighboring systems and participating in regional planning efforts
- Providing non-discriminatory transmission access

Buying and selling electricity in the wholesale markets – trading – occurs through bilateral and RTO/ISO transactions, as discussed below. Bilateral transactions occur in both traditional systems and in RTO/ISO regions. Pricing for bilateral transactions in both RTO/ISO and traditional regions incorporates both cost-based and market-based rates.

SUPPLYING LOAD

Load serving entities (LSE) serve customer load through a combination of self-supply, bilateral market purchases and purchases from RTO/ISO markets. Self-supply means that the LSE generates power from plants it owns or operates to meet demand. With bilateral purchases, the LSE buys power from a supplier. RTO/ISO market purchases means the supplying company purchases power through the RTO's/ISO's markets.

LSEs' sources of energy vary considerably. In ISO-NE, NYISO, and CAISO, the LSEs have divested much or all their generation. In these circumstances, LSEs supply their customers' requirements through bilateral and RTO/ISO market purchases. In PJM, MISO, and SPP, LSEs may own significant amounts of generation, either directly or through affiliates, and therefore use self-supply as well as bilateral and RTO market purchases.

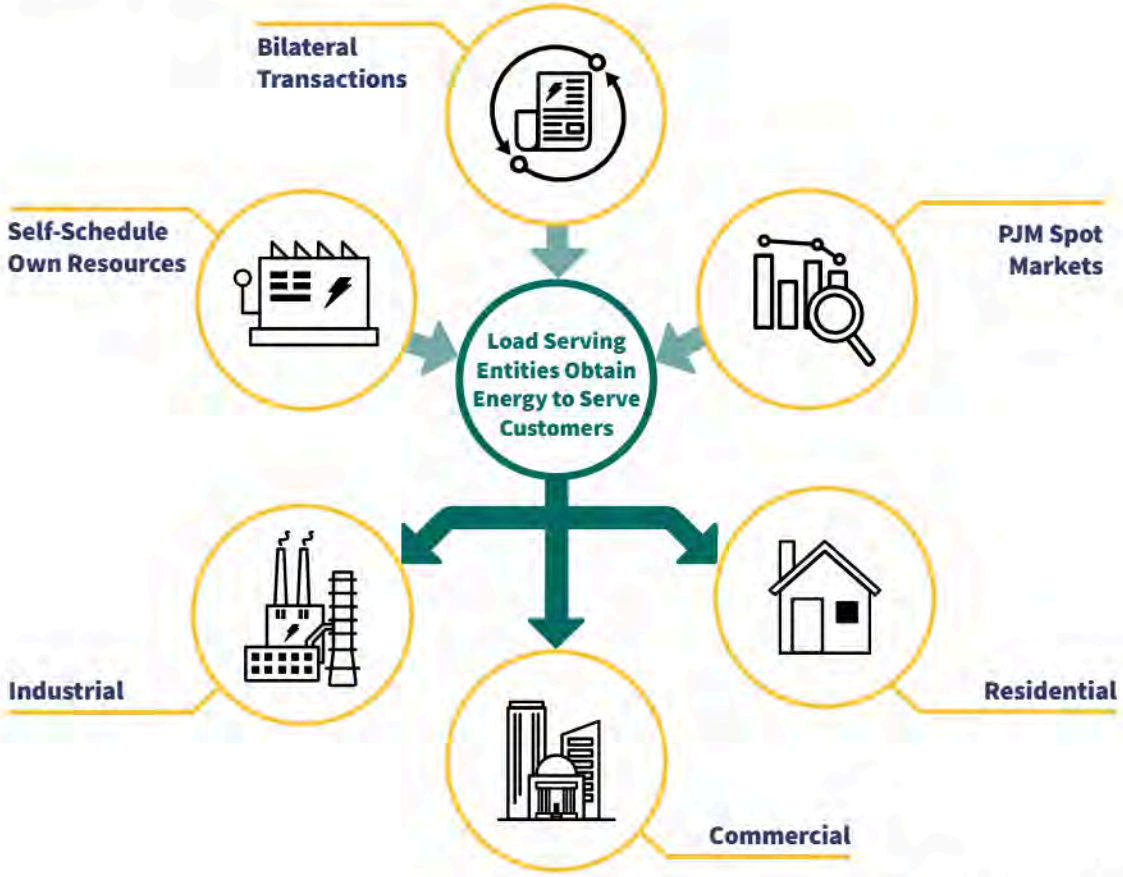
BILATERAL TRANSACTIONS

Bilateral transactions between two parties do not occur through an RTO/ISO and can occur through direct contact and negotiation, through a voice broker or through an electronic brokerage platform, such as the Intercontinental Exchange (ICE). The deals can range from standardized contract packages, such as those traded on ICE, to customized, complex contracts known as structured transactions. In bilateral transactions, buyers and sellers know the identity of the party with whom they are doing business.

Whether the trade is done on ICE, directly between parties or through another type of broker, the trading of standard physical and financial products, such as next-day on-peak firm or swaps, allows index providers to survey traders and publish price indexes. These indices provide price transparency.

Physical bilateral trades involving the movement of energy from one point to another require the parties to reserve transmission capacity to move the power over the transmission grid. Transmitting utilities are required to post the availability of transmission capacity and offer

Figure 2-5: Options for Energy Supply



Source: PJM Traditional Wholesale Electricity Markets

service on an OASIS website. Traders usually reserve transmission capacity on OASIS at the same time they arrange the power contract.

Transfers of power between Balancing Authority Areas (BAAs) require one of the parties to the transaction to submit a request for interchange, also known as an eTag.[112] The receiving BAA (the entity to which the power is transferred or sinks), or its agent, will process the eTag, ensure a reliability assessment has been completed, and send it to all parties named on the eTag. This ensures an orderly transfer of energy and provides transmission system operators with the information that they need to institute curtailments, as needed. Curtailments may be necessary when a change in system conditions reduces the capability of the transmission system to move power and requires some transactions to be reduced or cut.

Bilateral physical transactions that are conducted in RTO/ISOs are settled financially. Generators offer their power into the markets, and load is served through the power dispatched by the RTO/ISO. The RTO/ISO then settles bilateral transactions based on the prices in the contracts and the prices that occurred in their markets.

112 A BAA is a collection of generation, transmission, and loads within the metered boundaries of the entity (a Balancing Authority) that is responsible for balancing load, generation, and net interchange between other BAAs. Glossary of Terms Used in NERC Reliability Standards (March 2022), https://www.nerc.com/files/glossary_of_terms.pdf.

COST-BASED RATES

Cost-based rates are used to price most transmission services and some electricity when FERC determines that market-based rates are not appropriate, or when an entity does not seek market-based rate authority. Cost-based rates are set to recover costs associated with providing service and give a fair return on capital. These rates are typically listed in a published tariff.

The following are major inputs to setting cost-based electricity rates:

- Determining used-and-useful electricity plant costs. This may include the cost of generation facilities, transmission facilities, distribution plants and office and related administration facilities.
- Determining expenses for the production, transmission and distribution of electricity, including fuel and purchased power, taxes and administrative expenses.
- Establishing a fair return on capital, known as the cost of capital. This includes determining the cost of debt, common equity, preferred stock and commercial paper and other forms of short-term borrowing, such as lines of credit used to finance projects and provide cash for day-to-day operations.
- Allocating electric plant and other expenses among various customer classes and setting the rate structure and rate levels.

MARKET-BASED RATES

Under market-based rates, the terms of an electric transaction are negotiated by the sellers and buyers in bilateral markets or through RTO/ISO market operations. FERC grants market-based rate authority to electricity sellers that demonstrate that they and their affiliates lack, or have adequately mitigated, horizontal market power (typically based on whether the seller is a pivotal supplier and on the percent of generation owned by the seller relative to the total amount of generation available in a market). Sellers must also show that they lack, or have adequately mitigated, vertical market power (the ability to erect barriers to entry or influence the cost of production for competitive electricity suppliers). Wholesale sellers who have market-based rate authority and sell into day-ahead or real-time markets administered by an RTO/ISO do so subject to the specific RTO/ISO market rules approved by FERC. Thus, a seller in such markets must have an authorization from FERC and must also abide by the additional rules contained in the RTO/ISO tariff.

TRANSMISSION SERVICE

FERC requires that public utilities that own transmission lines used in interstate commerce offer transmission service on a nondiscriminatory basis to all eligible customers. The rates and terms of service are published in each utility's Open Access Transmission Tariff (OATT). Each utility's OATT specifies the transmission services available. Customers submit requests for transmission service through the OASIS. Utilities evaluate each transmission-service request using a model of the grid called a state estimator. Based on the model's estimation of the effects on the system, the request for transmission service is either approved or denied.

The two most common types of transmission service are network and point-to-point service. Network service allows a transmission customer the use of the entire transmission network to deliver generation from specified resources to specified loads. The price for service is cost-based and published in the OATT. Network service has higher priority than point-to-point service.

Point-to-point service involves paying for and reserving a fixed quantity of transmission capacity and moving power up to the reservation amount from one location, the point of receipt (POR), to another location, the point of delivery (POD). The POR and POD may be outside the transmission operator's footprint. Depending on availability, customers may purchase firm or non-firm point-to-point service for durations of one hour to multiple years.

Customers holding firm point-to-point transmission capacity may sell that capacity in a secondary market – such a sale is known as capacity reassignment. An entity holding transmission rights may want to resell

that capacity to another transmission customer in the secondary market because it is unneeded, or to make a profit. Resellers of transmission capacity are permitted to charge market-based rates for capacity reassignments, instead of the original cost-based rate at which they purchased the capacity. Most capacity reassignments are hourly, although capacity can also be reassigned on a daily, weekly, monthly, or yearly basis.[113]

If the market price of energy is greater at the POD than at the POR, the transmission has value. The transmission holder can capture this value by using the transmission – buying energy at the POR, moving it to the POD and selling it. Alternatively, the transmission holder can sell the transmission through a capacity reassignment. Thus, the price of a capacity reassignment should be consistent with, and rarely exceed, the expected price differential between the POD and the POR.

Transmission Planning

Each transmission-operating utility must participate in regional planning processes that identify transmission system additions and improvements needed to maintain reliability. Studies are conducted to test the transmission system against mandatory national reliability standards, as well as regional reliability standards. Planning studies may look 10-15 years into the future to identify transmission overloads, voltage limitations, and other reliability problems.

GRID OPERATIONS

Grid operators dispatch their systems using the least costly generation, consistent with the constraints of the transmission system and reliability requirements. The dispatch process occurs in two stages. For RTOs/ISOs, the market determines a day-ahead unit commitment, then updates the unit commitment and dispatches in real time. Grid operators in traditional utilities plan for the next day's dispatch, then update and implement that dispatch in real time.

Dispatch Planning

Grid operators decide which generating units should be committed in advance of actual operations. For RTOs/ISOs, this is done, in part, through the day-ahead markets and forecasts. For operators in traditional utilities, this is done through various planning and forecasting processes. Planning dispatch in advance of real-time operations is needed because some generating units need to obtain fuel or require several hours of lead time before they are brought online. In selecting the most economic generators to commit, operators take into account forecast load requirements and each unit's physical operating characteristics, such as how quickly output can be changed, maximum and minimum output levels and the minimum time a generator must run once it is started. Operators must also take into account each generating unit's cost factors, such as fuel and nonfuel operating costs, and the cost of environmental compliance.

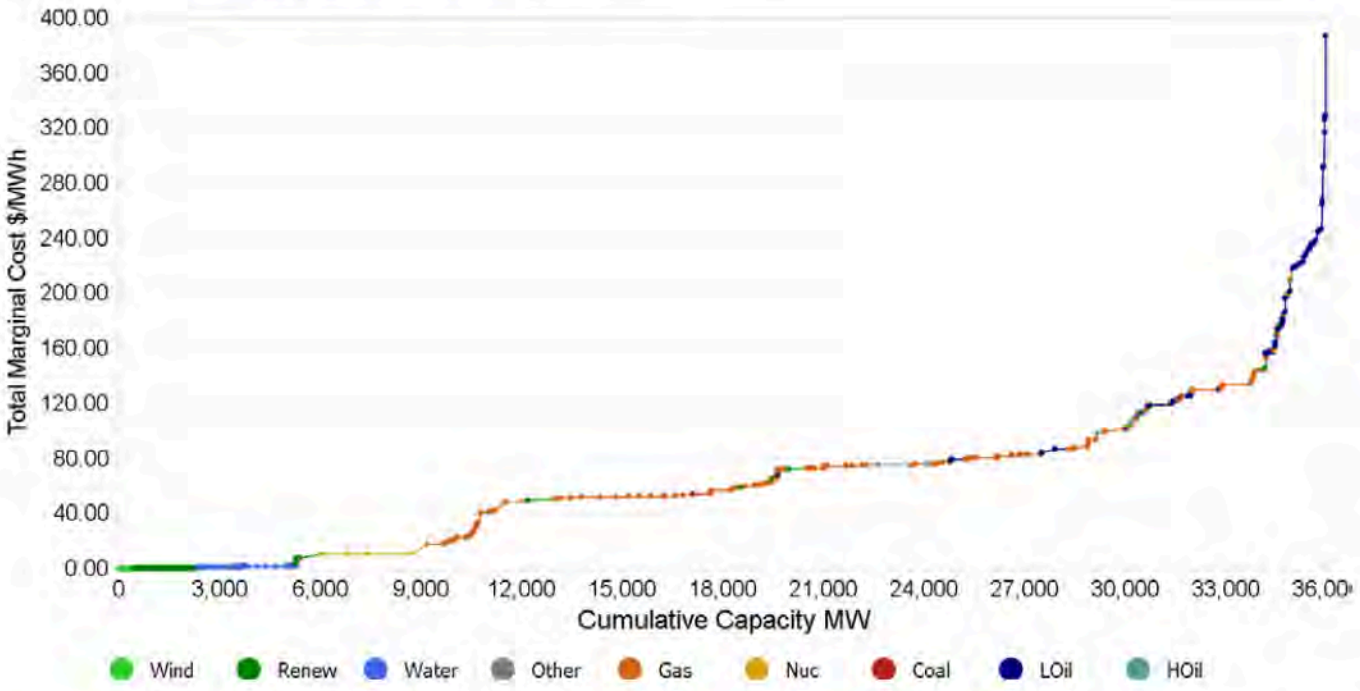
Forecast conditions can also affect how the transmission grid is optimally dispatched to reliably meet load. This is the security aspect of commitment analysis. The factors that can affect grid capabilities include generation and transmission facility outages, line capacities as affected by loading levels and flow direction, and weather conditions. If the security analysis indicates that the optimal economic dispatch cannot be carried out reliably, relatively expensive generators may have to be called upon to replace less-expensive units.

System and Unit Dispatch

Grid operators must decide the actual level at which each available resource should be operated, given the actual real-time load and grid conditions, so that reliability is maintained and overall production costs are minimized. Actual conditions will vary from those forecast prior to real-time, and grid operators must adjust the dispatch accordingly. As part of real-time operations, demand, generation and interchange (imports and exports) must be continually kept in balance to maintain a system frequency of 60 hertz.

113 FERC, *Electric Quarterly Reports, Downloads, Quarterly Filings* (2021), https://eqrreportviewer.ferc.gov.

Figure 2-6: Market Supply Curve for NYISO (Illustrative)



Source: Hitachi Energy, Velocity Suite[114]

This is typically done by automatic generation control (AGC) to change the generation dispatch as needed.

In general, dispatch occurs based on the cost of generation from given resources, with the lowest-cost resources dispatched first and the higher-cost resources dispatched last. The chart above is a depiction of the market supply curve for the New York Independent System Operator (NYISO). This is also commonly called the supply stack. In it, all the generating units in the New York market are shown, sorted according to their marginal cost of production. Their cost of production is shown on the vertical axis in terms of dollars per MWh. The cheapest units to run are to the left and the most expensive to the right.

Dispatch in New York, for example, first calls upon wind generating units, followed successively by hydroelectric, nuclear and coal-, gas- and oil-fired generating units.

This assumes that the generating units have sufficient resources – enough wind for the wind-powered generators or enough river flow for the hydroelectric plants, for example – and that sufficient transmission capability exists to deliver generator output and meet reliability needs.

In addition to these considerations, transmission flows must be monitored to ensure that the grid operates within voltage and reliability limits. If transmission flows exceed accepted limits, the operator must take corrective action, which could involve curtailing schedules, changing the dispatch or shedding load. Operators may check conditions and issue adjusted dispatch instructions as often as every five minutes.

ANCILLARY SERVICES

Ancillary services maintain electric reliability and support the transmission of electricity. These services

114 Derived from Hitachi Energy, Velocity Suite, *Supply Curve Analyst, Form EIA 860, NERC Electric Supply and Demand database, FERC Form 1, FERC Form 714, ISO Load Data, Hitachi Energy Primary Research, et al* (February 2023).

are produced and consumed in real-time, or in the very near term. NERC and regional entities establish the minimum amount of each ancillary service that is required for maintaining grid reliability.[115]

Regulation matches generation with very short-term changes in load by moving the output of selected resources up and down via an automatic control signal, typically every few seconds. The changes to output are designed to maintain system frequency at 60 hertz. Failure to maintain a 60-hertz frequency can result in systemic failure of an electric grid.

Operating reserves are needed to restore load and generation balance when a supply resource trips offline. Operating reserves are provided by generating units and demand resources that can act quickly, by increasing output or reducing demand, to make up a generation deficiency. There are three types: spinning reserves, non-spinning reserves and supplemental reserves.

Spinning reserves are provided by generators that are online (synchronized to the system frequency) with some unloaded (spare) capacity and capable of increasing its electricity output within a specified period, such as 10 minutes. During normal operation, these reserves are provided by increasing output on electrically synchronized equipment or by reducing load on pumped storage hydroelectric facilities. Synchronized reserve can also be provided by demand-side resources.

Non-spinning reserves are provided by generating units that are not necessarily synchronized to the power grid but can be brought online within a specified amount of time, such as 10 minutes. Non-spinning reserve can also be provided by demand-side resources.

Supplemental reserves are provided by generating units that can be made available within a specified amount of time, such as 30 minutes and are not necessarily synchronized with the system frequency.

Blackstart generating units have the ability to go from a shutdown condition to an operating conditi on and start delivering power without any outside assistance from the electric grid. Hydroelectric facilities and diesel generators predominately have this capability. These are the first facilities to be started up in the event of a system failure or blackout to restore the rest of the grid.

Reactive power: Electricity consists of current, the flow of electrons, and voltage, the force that pushes the current through the wire. Reactive power is the portion of power that establishes and maintains electric and magnetic fields in AC equipment. It is necessary for transporting AC power over transmission lines, and for operating magnetic equipment, including rotating machinery and transformers. It is consumed by current as it flows. As the amount of electricity flowing on a line increases, so does the amount of reactive power needed to maintain voltage and move current. Power plants can produce both real and reactive power and can change the output of both. Special equipment installed on the transmission grid is also capable of injecting reactive power to maintain voltage.

WEATHER

Weather is the single most important factor affecting the level of electricity demand and, thus, is a major factor in grid operations. System operators therefore rely heavily on weather forecasts to ensure they have the right generation, in the right locations, to run the grid reliably.

Weather affects grid operations in other ways, as well. Primary among these is on the productivity of certain types of power generators: wind and hydroelectric. Wind turbines' power output changes

115 For additional information on the definitions of ancillary services, NERC, *Glossary of Terms Used in NERC Reliability Standards*, (March 2022), https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

with wind availability and speed, which affects cost of wholesale power. Solar generation declines with cloud cover, which not only decreases available generation but can increase demand as behind-the-meter solar, such as residential and commercial installations, decrease their supply to retail users.

Hydroelectric plants rely on rain and snowfall to provide the river flow needed for their output. Geographically, this is most important in the Pacific Northwest, where seasonal hydroelectric plant output is a critical source of power. Rain and the melting of winter snowpack feed the Columbia and Snake River systems. Surplus power from these generators is typically exported to California to help meet summer peak demand, increase reliability and lower prices.

Temperature can also affect the output of other power plants and capacity of transmission lines. Thermal plants that use a turbine – coal, gas, oil, and nuclear plants – become less efficient at higher temperatures. Additionally, the capacity of transmission lines is limited by heat because the conductive material used in fabrication becomes more electrically resistant as they heat up, limiting their throughput capability.

Traditional Electricity Systems

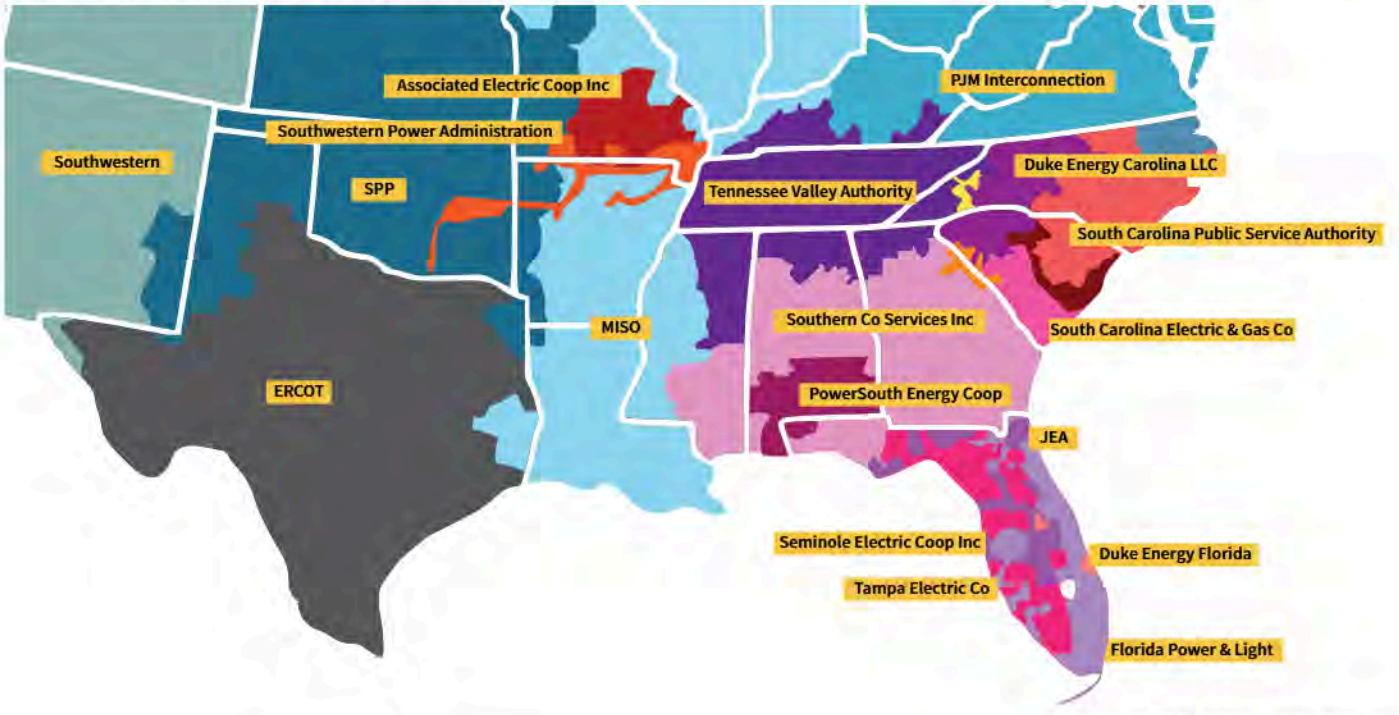
Traditional wholesale electricity markets exist primarily in the Southeast and the West outside of California, where utilities are responsible for system operations and management, and, typically, for providing power to retail consumers. Utilities in these markets are frequently vertically integrated – they own the generation, transmission and distribution systems used to serve electricity consumers. They may also include federal systems, such as the Bonneville Power Administration (BPA), the Tennessee Valley Authority and the Western Area Power Administration. Wholesale physical power trading typically occurs through bilateral transactions. In addition to the responsibilities listed in the overview to this section, a utility in a traditional region has the following responsibilities:

- Generating or obtaining the power needed to serve customers (this varies by state)
- Dispatching resources based on some cost minimizing algorithm
- Ensuring the reliability of the transmission grid

Southeast Wholesale Market Region

The Southeast electricity market is a bilateral market that includes all or parts of Florida, Georgia, Alabama, Mississippi, North Carolina, South Carolina, Missouri, and Tennessee. It encompasses the Southeastern Electric Reliability Council (SERC) NERC region. Major hubs include Into Southern and the Tennessee Valley Authority (TVA). The Southeast region's hourly peak demand is greater than 203 GW.[116] While traditional bilateral trading continues in the Southeast, some utilities in the region have created a trading platform, the Southeast Energy Exchange Market (SEEM), discussed further below. Southern Company also conducts an auction for some of its available generation, also discussed further below.

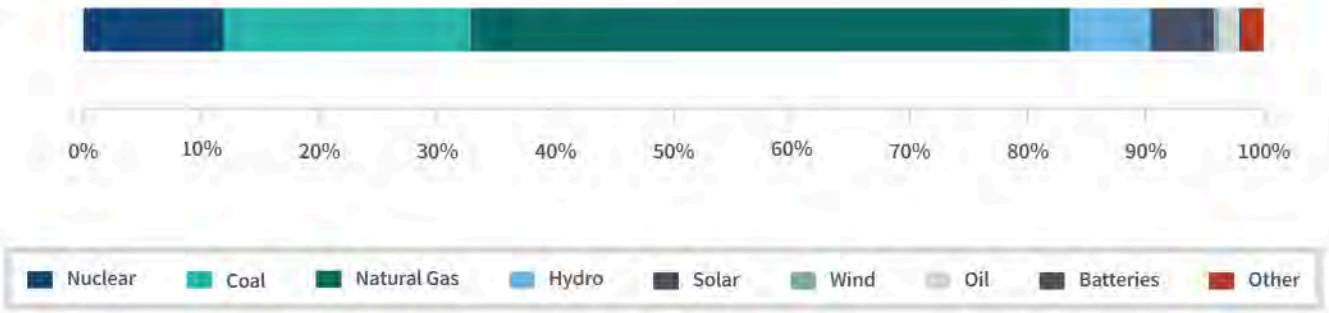
Figure 2-7: Southeast Electric Region



Source: Hitachi Energy, Velocity Suite

116 The hourly peak demand observed between 2000 and 2020. Based on FERC Form 714, Annual Electric Balancing Authority Area and Planning Area Report. Derived from the Balancing Authority Areas within the SERC NERC region, using the Hitachi Energy, Velocity Suite, Balancing Authority Area Net Energy for Load & Peak Demand dataset.

Figure 2-8: Southeast Electric Region Capacity Mix



Source: EIA Form 860-M[117]

Supply Resources

The total generating capacity in the Southeast Electric Region is over 256 GW and is predominately composed of natural gas and coal-fired generators. Hydroelectric and nuclear capacity are also substantial resources in the region.

The Southeast generates most of its electricity from coal, nuclear, and natural gas-fired plants, as shown in the bar chart above.

The TVA sub-region has a majority of its capacity and output from coal and nuclear, while the Virginia-Carolina (VACAR) sub-region has the highest utilization of nuclear generation in the Southeast.

TRADING AND MARKET FEATURES

Physical sales in the Southeast are done bilaterally and long-term energy transactions are particularly prominent, compared to short-term transactions. Many long-term agreements involve full-requirements contracts or long-term power purchase agreements. For example, Southern Company's short-term transactions account for around 30 percent of its total wholesale energy sales in 2021.[118]

Short-term energy is traded among various entities, including investor-owned utilities, municipal utilities, public utility districts, independent power producers, and marketers. Some of the largest sellers of short-term power include Southern Company, North Carolina Municipal Power Agency, Cargill, and Exelon.

Industry-referenced trading points for short-term bilateral transactions in the Southeast include the following locations: Into Southern, TVA, VACAR, and Florida. Volumes for short-term transactions can be low, particularly under normal weather conditions. Overall demand for short-term transactions tends to rise during periods of system stress, for example summer heat waves or winter cold snaps.

The Southeast has relatively low volumes of short-term trades compared to the Western regions. Thus, there is limited data on that price index publishers have on which to base their price reporting. Given the bilateral nature of wholesale power transactions in the Southeast, and a relatively small market for short-term transactions, interest in financial power products in the Southeast is weak.

117 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, *Preliminary Monthly Electric Generator Inventory* (based on Form EIA-860M) (released February 2022), https://www.eia.gov/electricity/data/eia860m/.

118 FERC, *Electric Quarterly Reports, Downloads, Quarterly Filings* (2021), https://eqrreportviewer.ferc.gov.

SOUTHEAST ENERGY EXCHANGE MARKET

The Southeast Energy Exchange Market (SEEM) launched on November 9, 2022. However, on July 14, 2023, the U.S. Court of Appeals for the D.C. Circuited remanded to FERC orders addressing the Seem. Consequently, the SEEM proposal is now pending before the Commission once again.

SOUTHERN COMPANY AUCTION

Southern Company has held daily and hourly auctions for power within its balancing area since April 2009 as a requirement of Southern Company's market-based rate tariff. This BAA encompasses the service territories of Southern Company utilities: Georgia Power, Alabama Power, Mississippi Power, and Gulf Power. The products included in the auction are day-ahead power and real-time power.

According to the auction rules, Southern Company must offer all of its available uncommitted thermal generation capacity into the auction, after regulation and contingency reserves are met. The auction is intended to mitigate the potential ability of Southern Company to exercise market power within its balancing authority area and certain adjacent balancing authority areas. In February 2017, Southern Company revised its market-based rate tariff to cap all market-based sales of less than one year outside of the auction at a cost-based tariff rate.[119]

Western Wholesale Market Regions

The power markets in the western United States are primarily bilateral markets. A key exception is most of California and portions of Nevada, which operate under CAISO. Further, several entities buy and sell electricity in a regional, short-term markets run by CAISO, called the Western Energy Imbalance Market (WEIM), and the SPP-run Western Energy Imbalance Service (WEIS). CAISO and SPP are discussed further in the RTO and ISO Markets section. The West includes the Western Power Pool (WPP), the Rocky Mountain Power Area, and the Arizona, New Mexico, Southern Nevada Power Area within the Western Electricity Coordinating Council (WECC), a regional entity. These areas contain over 30 balancing authority areas responsible for dispatching generation, procuring power, operating the transmission grid reliably, and maintaining adequate reserves.[120]

NORTHWEST ELECTRIC REGION

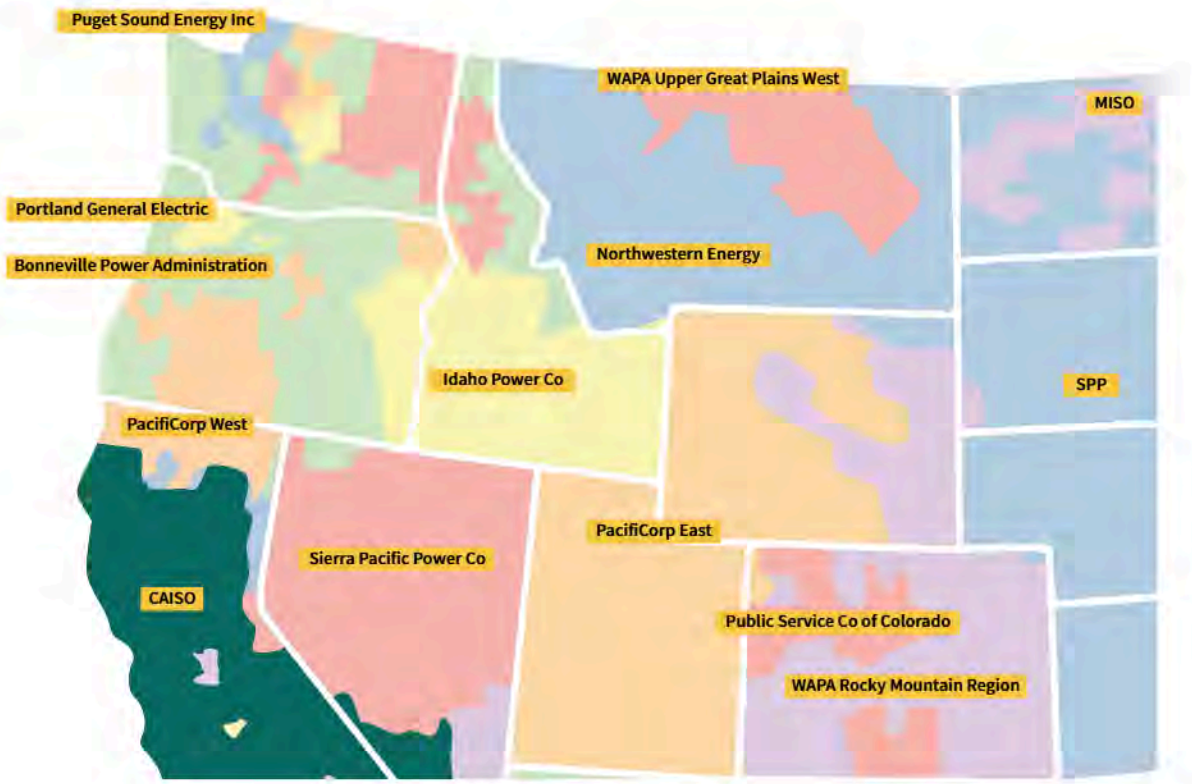
The Northwest Electric Region is composed of the Northwest Power Pool (NWPP) NERC region in the northwestern section of the Western Electric Coordinating Council (WECC) NERC region. The hourly peak demand is approximately 49 GW[121]

119 *Alabama Power Company*, 158 FERC ¶ 61,131 (2017) (February 2, 2017 Order) (order accepting market-based rate tariff revisions subject to condition).

120 Western Electricity Coordinating Council, *Western Interconnection Balancing Authorities* (accessed November 2022), https://www.wecc.org/_layouts/15/WopiFrame.aspx?sourcedoc=/Administrative/Balancing_Authorities_JAN17.pdf&action=default&DefaultItemOpen=1.

121 The hourly peak demand observed in a given month between 2000 and 2020. Based on FERC Form 714, *Annual Electric Balancing Authority Area and Planning Area Report*. Derived from the Balancing Authority Areas within the NWPP NERC subregion, using the Hitachi Energy, Velocity Suite, Balancing Authority Area Net Energy for Load & Peak Demand dataset.

Figure 2-9: Northwest Electric Region



Source: Hitachi Energy, Velocity Suite

Supply Resources

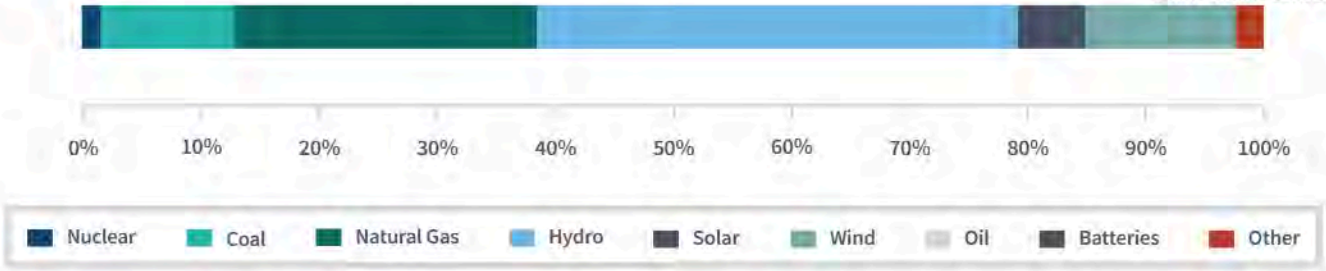
The total capacity in the Northwest Electric Region is approximately 79 GW and is primarily composed of hydroelectric, natural gas, and coal-fired generators, as shown in the bar chart below. Wind generator capacity is also a significant resource for the region.

The Northwest has a unique resource mix, as demonstrated in the bar chart below, with hydroelectric generation capacity comprising approximately 40 percent of the power supply, which is sourced from many dams that are in the Columbia River system. The largest dam, Grand Coulee, can produce up to as much power as six nuclear plants. Due to the large amount of hydroelectric generation, the Northwest typically has low-cost power during the spring and early summer. During these periods, the region exports power to neighboring regions, especially California, where power prices are typically higher.

The amount of hydroelectric power produced depends on a number of factors, some natural and some controllable. On a seasonal basis, the intensity and duration of the water flow is driven by snowpack in the mountains, the fullness of the reservoirs, and rainfall. On a short-term basis, the levels of hydroelectric power generation output are influenced by decisions to release water locally and upstream to generate power, as well as local water-use decisions that are independent of the economics of the power markets, based on recreation, irrigation, and wildlife considerations, for example. The peak hydroelectric power generation period begins in the spring, when the snow melts, and may last into early summer. When less water is available, the Northwest may rely more on its coal and natural gas generation, and occasionally import power from neighboring regions, including Canada, when loads are high.

Figure 2-10: Northwest Electric Region Capacity Mix

Source: EIA Form 860-M



Trading and Market Features

Two Canadian BAAs, Alberta Electric System Operator

The water forecast affects the forward market for electricity in the Northwest. Similarly, the daily water flow conditions influence the prices in the daily physical market. When there is an abundance of hydroelectric generation, the Northwest will export as much as possible on the transmission lines leading into California and elsewhere in the West. Sometimes in off-peak hours, more electricity is available than can move through transmission lines or be used locally, so electric prices become negative.

The largest seller of wholesale power in the region is the BPA, a federal agency that markets the output from federally owned hydroelectric facilities, as well as a non-federal nuclear plant and several other smaller non-federal power plants. BPA meets approximately one-third of the firm energy supply in its service territory and owns 75 percent of the region's high-voltage transmission.[122] BPA gives preference to municipal and other publicly owned electric systems in allocating and pricing its generation output.[123]

and British Columbia Hydro, are also substantial suppliers of energy to the United States via the Northwest Electric Region. These Canadian BAAs often import power to, and export power from, the United States, depending on market conditions. The Canadian BAAs generally import power from the United States when prices are low in order to save water in their hydroelectric reservoirs. The water is later released to generate and sell hydroelectric power during higher-priced periods[124]

The Northwest region trading points for bilateral transactions include Mid-Columbia (Mid-C), California-Oregon Border (COB), Nevada-Oregon Border (NOB), and Mona (Utah). Of these, Mid-C is the most actively traded location.

SOUTHWEST ELECTRIC REGION

The Southwest electric market encompasses Arizona, New Mexico, and Southern Nevada in the WECC NERC region. The hourly peak demand is approximately 25 GW.[125]

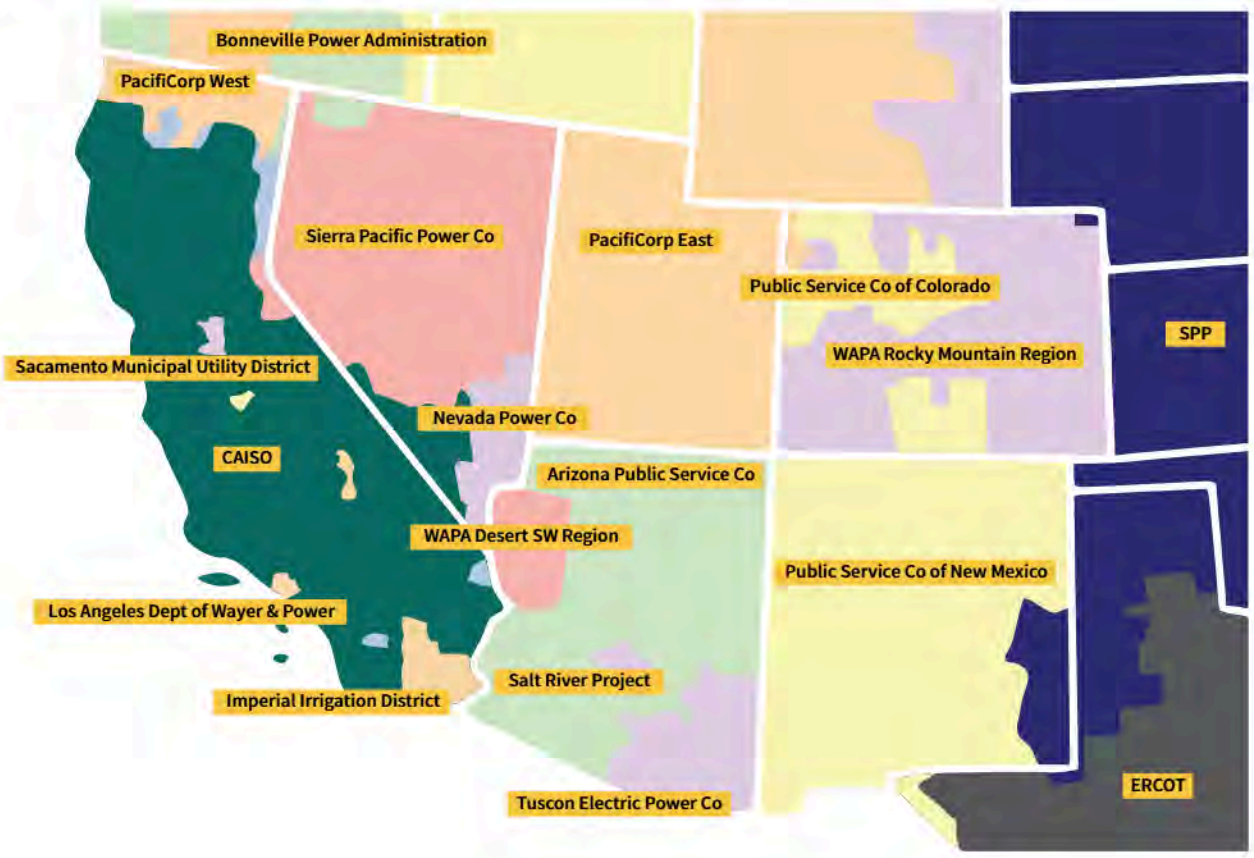
122 Bonneville Power Administration, *BPA Overview,* 45, https://energy.gov/sites/prod/files/2016/01/f28/0911review_ikakoula.pdf.

123 Bonneville Project Act, 16 U.S.C. §§ 832-832m (2000).

124 National Energy Board, *Market Snapshot: Which states trade electricity with British Columbia?* (September 2022) https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/market-snapshots/; National Energy Board, *Market Snapshot: Why Canada is one of the world's largest electricity consumers* (August 2022), https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/market-snapshots/

125 The hourly peak demand observed between 2000 and 2020. Based on *FERC Form 714, Annual Electric Balancing Authority Area and Planning Area Report*. Derived from the Balancing Authority Areas within the AZ/NM/SNV NERC subregion, using the Hitachi Energy, Velocity Suite, Balancing Authority Area Net Energy for Load & Peak Demand dataset.

Figure 2-11: Southwest Electric Region



Source: Hitachi Energy, Velocity Suite

Supply Resources

The total capacity in the Southwest Electric Region is over 40 GW and is predominately composed of natural gas and coal-fired generators. Hydroelectric, wind, solar, and nuclear capacity account for the majority of the remaining capacity, as shown in the bar chart below.

The majority of generation in the Southwest is produced from natural gas and coal, as demonstrated in the bar chart above. The coal generators are generally located in close proximity to coal mines, resulting in low delivered fuel costs. Some generation is jointly owned among multiple nearby utilities, including the Palo Verde nuclear plant, a plant with three units totaling approximately 4,000 MW,[126] which has owners in California and the Southwest.[127] The Southwest is also characterized by large amounts of solar capacity, as this region has the highest solar potential in the nation.[128]

Trading and Market Features

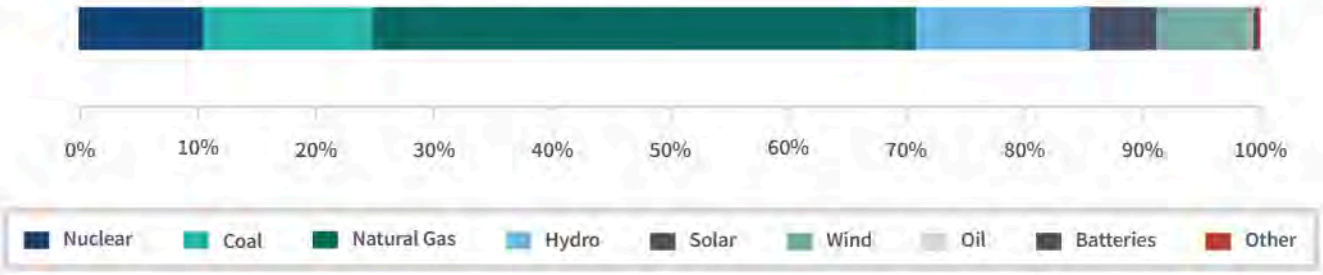
The Southwest region is summer-peaking and experiences peak loads coincident with air conditioning demand. The daily high temperature averages above 100 degrees from June through mid-September in Phoenix.

126 Derived from EIA, *Form EIA-860, 3-1-Generator_Y2021 Report*, (2021), https://www.eia.gov/electricity/data/eia860/.

127 Plant Operating License, Palo Verde, Unit 1, Current Facility Operating License NpF-41, Tech Specs, Revised 08/18/2022, https://www.nrc.gov/info-finder/reactors/palo1.html.

128 Western Electricity Coordinating Council, *State of the Interconnection*, at 9 (September 2017), https://www.wecc.biz/epubs/StateOfTheInterconnection/.

Figure 2-12: Southwest Electric Region Capacity Mix



Source: EIA Form 860-M[129]

However, power prices tend to be the highest when there is also hot weather in Southern California, creating competition for the region's generation resources. The Southwest trading points include Palo Verde, Four Corners, and West Wing. Of these, Palo Verde is the most actively traded location.

RTO and ISO Markets

Two-thirds of the population of the United States is served by electricity markets run by regional RTOs/ISOs. A key distinction between RTO/ISO markets and vertically integrated utilities, municipal utilities and co-ops is that RTO/ISO markets deliver electricity through competitive market mechanisms coordinated by a non-profit entity over a large geographic footprint. Further, RTOs/ISOs do not own or conduct maintenance on the transmission or other resources involved in providing electric service.

Currently, seven RTO/ISOs operate in the United States, listed below in order of the size of their all-time peak load.[130] FERC regulates all RTOs/ISOs except ERCOT. In addition to operating RTOs/ISOs, SPP and CAISO also operate regional short-term or imbalance energy markets, which, while not RTOs/ISOs, provide markets for real-time energy sales and purchases. SPP operates the WEIS and CAISO runs the WEIM, which are discussed at the end of the SPP and CAISO sections below.

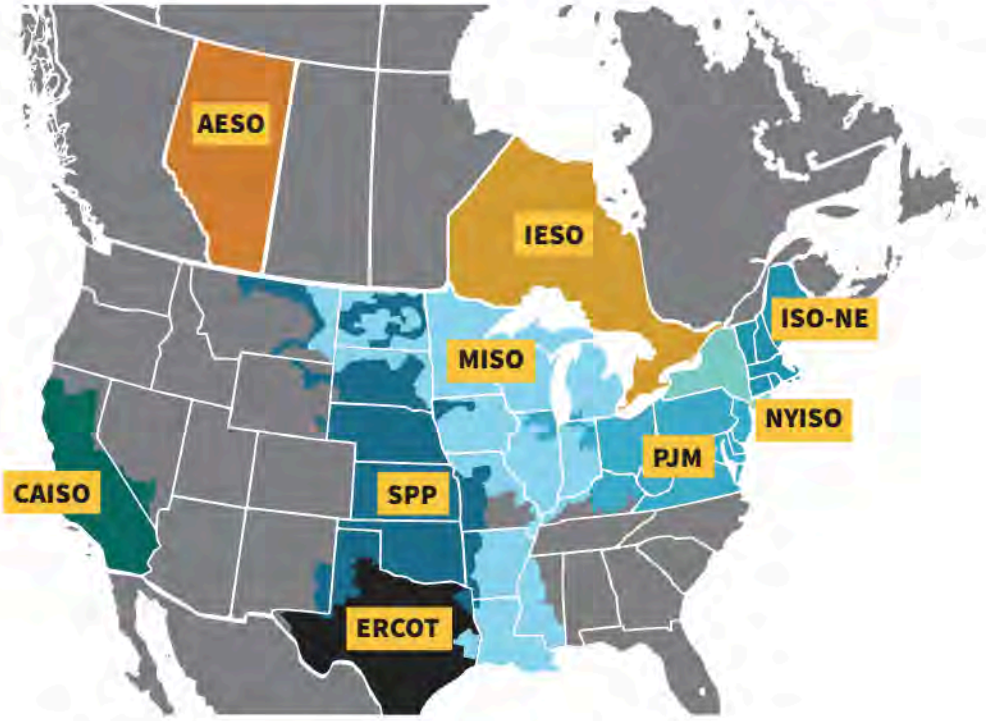
- PJM, 165 GW (summer of 2006)
- MISO, 127 GW (summer of 2011)
- ERCOT, 80 GW (summer of 2022)
- SPP, 53 GW (summer of 2022)
- CAISO, 52 GW (summer of 2022)
- NYISO, 34 GW (summer of 2013)
- ISO-NE, 28 GW (summer of 2006)

Unlike traditional electricity systems, RTOs/ISOs also operate competitive, nondiscriminatory electricity markets, which allow resource owners to offer resources and load-serving entities to submit bids for generation. These markets are the primary mechanism for dispatching resources, managing transmission congestion and pricing electricity. RTOs/ISOs work in conjunction with the resources and transmission-owning resources that participate in the RTO/ISO to maintain reliability. RTOs/ISOs also coordinate the maintenance of generation and transmission systems and oversee a transmission planning process to identify needed upgrades in both the near- and long-term.

129 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. EIA, *Preliminary Monthly Electric Generator Inventory* (based on Form EIA-860M) (February 2022), https://www.eia.gov/electricity/data/eia860m/.

130 For source information on the peak load statistics for PJM Interconnection, Midcontinent ISO, Southwest Power Pool, California ISO, New York ISO, and New England ISO, see the individual region's description later in this chapter. For ERCOT, see *ERCOT, Fact Sheet*, (October 2022), https://www.ercot.com/files/docs/2022/02/08/ERCOT_Fact_Sheet.pdf.

Figure 2-13: North American Regional Transmission Organizations and Independent System Operators



Source: Hitachi Energy, Velocity Suite

RTO/ISO FEATURES

All RTOs/ISOs function as non-profit entities that operate markets to dispatch and price electricity across a large, defined footprint. To do this, the RTOs/ISOs perform functions such as operating day-ahead and real-time markets, but also perform an array of functions not directly part of the markets, but essential to allow their efficient performance. For example, RTOs/ISOs manage the flow of payments between market participants. The next section discusses markets operated by RTOs/ISOs. The remainder of this section discusses key RTO/ISO support features or functions.

Governance

RTOs/ISOs, resource owners and operators, investor-owned, public and cooperative utilities, marketers and financial entities participate in the RTO/ISO under a governance structure and rules determined through RTO/ISO-run processes.[131] RTO/ISO governance typically involves a board of directors and stakeholder committees, which, among other things, review rule revisions. Rules underlying RTO/ISO functions are included in the RTO's/ISO's tariff and are subject to FERC's approval. Details on rule implementation can be found in RTO's/ISO's Business Practice Manuals.

Financial Policies

Financial settlement is the process through which payments due from customers, and to generators, are calculated. Such settlements are based upon day-ahead schedules, real-time metering, interchange schedules, internal energy schedules, ancillary service obligations, transmission reservations, energy prices, Financial Transmission Rights (FTR) positions, and capacity positions. Each market participant's invoice of charges and credits includes the costs of services used to serve load and the costs for operating the RTO/ISO.

131 Order No. 2000, *Regional Transmission Organizations*, 89¶61,285, (December 20, 1999).

Generally, customers receive weekly or monthly invoices stating their charges and credits. Weekly invoices must be settled within a few days of being issued, while monthly invoices must be paid within either one or two weeks, depending on the policies of each RTO/ISO. All payments are made electronically.

While RTO/ISO energy and ancillary service markets operate to price electricity at a level that compensates resources for their energy supply and meet other requirements of their tariffs, instances do occur where additional cost recovery is needed – this is commonly known as uplift. The need for uplift may arise, for example, when unplanned transmission and generation outages occur, resulting in actual operations differing from the assumptions included in the market models underlying the energy and ancillary service markets.[132]

Credit Policies

RTOs/ISOs settle the many financial charges that are paid by, or to, market participants. As RTOs/ISOs are non-profit entities with no financial interest in the markets they operate, any financial shortfall or over-collection goes to the various market participants. To protect the RTO/ISO and its market participants, each RTO/ISO has tariff provisions and other policies to ensure that market participants have the ability to pay, known as credit policies.[133] Defaults by market participants in RTOs/ISOs are rare and the costs have generally been spread across the market. Credit policies contain provisions related to credit evaluations, credit limits, forms of collateral, and the consequences of violations or defaults.

Transmission Planning

RTO/ISOs coordinate transmission planning for their footprint as required under Order 1000, a comprehensive transmission rule issued by FERC in 2011.[134] Each of the RTO/ISOs has system-wide or regional planning processes that identify transmission system additions and improvements that are needed to keep electricity flowing. Studies are conducted to test the transmission system against mandatory national reliability standards, as well as regional reliability standards. The RTO/ISO transmission planning studies may look 10-15 years into the future to identify transmission overloads, voltage limitations, and other reliability problems. RTO/ISOs then develop transmission plans in collaboration with transmission owners to resolve potential problems that could otherwise lead to overloads and blackouts. This process culminates in one recommended plan for the entire RTO/ISO footprint.

RTO/ISO MARKETS AND ASSOCIATED FUNCTIONS

RTOs/ISOs operate several markets and functions that address the physical supply of electricity and its pricing – energy and capacity markets. To physically provide the supply of electricity at all times in all places, RTOs/ISOs operate energy markets that LSEs use to procure energy and ancillary services. Some RTOs/ISOs also operate capacity markets, which, along with underlying resource adequacy rules, ensure sufficient capacity is available. RTOs/ISOs also operate financial markets associated with the energy markets – financial transmission rights and virtual transactions.

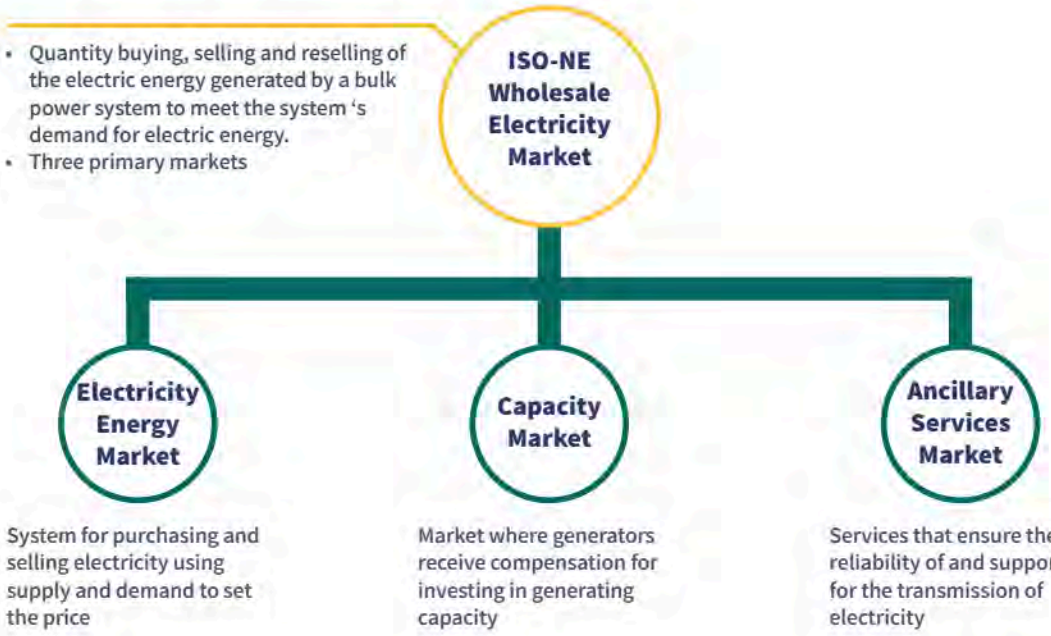
RTOs/ISOs must define rules and operate programs needed to ensure efficient market operations. The operations of the markets are discussed further below. Underlying these market operations are an extensive list of detailed rules and functions. For example, these rules detail what types of resources can participate, at limits on what prices resources can offer, and the operation of an independent market monitoring program:

132 Order No. 844, *Uplift Cost Allocation and Transparency in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 163¶61,041, (April 19, 2018).

133 Order No. 741, *Credit Reforms in Organized Wholesale Electric Markets*, 133¶61,060, (October 21, 2010).

134 Order No. 1000, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 135¶61,051, (July 21, 2011).

Figure 2-14: ISO-NE Wholesale Electricity Market



Source: ISO-NE

Resource Participation In addition to generation, demand response resources (DR), DER, energy efficiency and batteries may participate in RTO/ISO markets.[135]

Offer Caps Each RTO/ISO caps a resource's supply offer at $1,000. If a resource's costs exceed $1,000, they may request authority to offer at a higher price that reflects their verified costs. Offers up to $2,000 may be used by the RTO/ISO to set the locational marginal price.[136]

Market Monitoring Each RTO/ISO must have independent market monitors which oversee various aspects of the RTO's/ISO's markets and performance, such as market power mitigation, assessment and referral of market manipulation and assessing and reporting on the competitiveness of market operations.[137]

Energy Markets

All RTOs/ISOs have day-ahead and real-time markets. The day-ahead market schedules electricity production, ancillary services commitments and consumption before the operating day, whereas the real-time market reconciles any differences between the schedule in the day-ahead market and the real-time conditions. Both the day-ahead and real-time markets reflect reliability criteria and infrastructure conditions, such as transmission topology and limitations, resource outages, and resource operating limits.

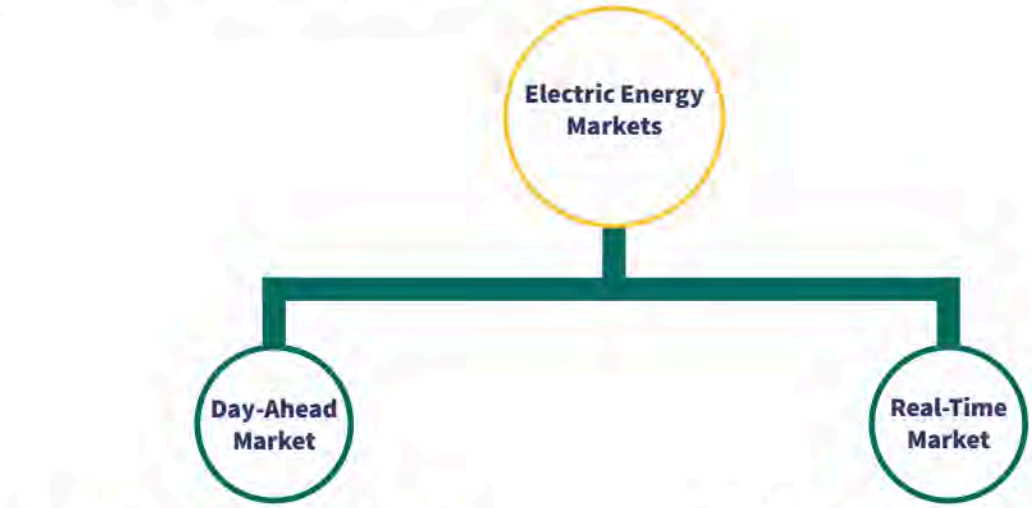
Energy markets operate to match the supply options offered by resource oprators to the demand bid in by LSEs and RTO/ISO demand forecasts. The market models select the most economic supply offers available,

135 Order No. 2222, *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 172¶61,247; Order No. 841, *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 162¶61,127 (2018); Order No. 745, *Demand Response Compensation in Organized Wholesale Energy Markets*, 134¶61,187, (March 15, 2011).

136 Order No. 831, *Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 157¶61,115, (November 17, 2016).

137 Order No. 719, *Wholesale Competition in Regions with Organized Electric Markets*, 125¶61,071.

Figure 2-15: ISO-NE Wholesale Electricity Market



Source: ISO-NE

recognizing physical resource and transmission limitation. The overall market price for electricity is determined by the highest offer accepted. However, transmission limitations may require the market to adjust the offers selected, which can change the price for different locations in the RTO/ISO – the locational marginal price (LMP). The RTO/ISO markets calculate the LMP at each location on the power grid. The LMP reflects the marginal cost of serving load at the specific location, given the set of resources that are being dispatched and the limitations of the transmission system. LMP has three elements: an energy charge, a congestion charge, and a charge for transmission system energy losses.

If there are no transmission constraints, known as transmission congestion, LMPs will not vary significantly across the RTO/ISO footprint. However, when transmission congestion occurs, LMPs will vary across the footprint because operators are not able to dispatch the least-cost generators across the entire region and some more expensive generation must be dispatched to meet demand in the constrained area.

When transmission is constrained, the highest variable cost unit that must be dispatched to meet load within transmission-constrained boundaries will set the LMP in that area. All sellers receive the LMP for their location and all buyers pay the price for their location.

The primary means used for relieving transmission congestion constraints is by changing the output of generation at different locations on the grid. The market-based LMP sends price signals that reflect congestion costs to market participants. Thus, LMPs take into account both the impact of specific generators on the constrained facility and the cost to change (redispatch) the generation output to serve load. This process is known as security-constrained economic dispatch.

This redispatch could be implemented by using non-market procedures, such as transmission loading relief (TLR). NERC established the TLR process for dealing with reliability concerns when the transmission network becomes overloaded and power flows must be reduced to protect the network. A TLR is used to ration transmission capacity when the demand for transmission is greater than the available transmission capacity (ATC). The rationing is a priority system that cuts power flows

based on size, contractual terms and scheduling.

Day-Ahead Energy Markets

The day-ahead energy market produces financially binding schedules for the production and consumption of electricity one day before its production and use (the operating day). The purpose of the day-ahead market is to give generators and load-serving entities a means for scheduling their activities with sufficient lead time to procure fuel or bring up resources with longer start times. The day-ahead bids and offers are based on a forecast of loads and are consistent with resources' business strategies.

In day-ahead markets, offers of supply and demand bids are compiled hours ahead of the beginning of the operating day. The RTO/ISO then runs a computerized market model that matches demand and supply throughout the market footprint for each hour of the day. Additionally, the model must account for changing system capabilities that occur, based on weather and equipment outages, transmission and resource capabilities, and the rules and procedures that are used to ensure system reliability.[138] The market rules dictate that generators submit supply offers and that loads submit demand bids to the RTO/ISO by a deadline that is typically in the morning of the day-ahead scheduling. Typically, 95 percent of all load is scheduled in the day-ahead market and the rest is scheduled in real-time. Generation and demand bids that are scheduled in the day-ahead market are settled at the day-ahead market prices.

Inputs into setting a day-ahead market schedule include:

- Generators' offers to sell electricity for each hour
- Load-serving entities' bids to buy electricity for each hour
- Demand-response offers by customers to curtail usage of electricity
- Virtual demand bids and supply offers
- Operational information about the transmission grid and generating resources, including planned or known transmission and generator outages, the physical characteristics of generating resources including minimum and maximum output levels and minimum run time, and the status of interconnections to external markets.

Real-Time Energy Markets

The real-time market is used to balance the differences between the day-ahead scheduled amounts of electricity cleared in the day-ahead market and the actual real-time load and supply. The real-time market is run in five-minute intervals and clears a much smaller volume of energy and ancillary services than the day-ahead market (some RTOs/ISOs also run hour-ahead and 15 minutes- ahead of the operating interval). The real-time market also provides supply resources additional opportunities for offering energy into the market. When the real-time generation and load are different from the day-ahead cleared amount, the difference is settled at the real-time price.

Real-time market prices are significantly more volatile than day-ahead market prices. This stems from demand uncertainty, transmission and generator forced outages, and other unforeseen events. Since the day-ahead market generally is not presented with these events, it produces more stable prices than in real-time. Also, because the volumes in the real-time market are much smaller, there is an increased likelihood of supply and demand imbalances, which can lead to both positive and negative price movements.

Ancillary Services

RTOs/ISOs procure ancillary services, which are described in the Electricity Supply and Delivery Section, through the day-ahead and real-time market dispatch. RTOs/ISOs primarily procure ancillary service through their market mechanisms, although they compensate blackstart and voltage service based on the cost of providing the service (cost-of-service). Changes in the

138 In evaluating which generators provide the power to meet hourly load, the market model assesses whether the power flows can travel without exceeding the physical capability of any transmission path. If the model shows such a violation of transmission capability, the combination of assigned generators will be changed in a process known as redispatch.

resources providing supply have necessitated changes in ancillary service procurement and compensation. For example, the advent of faster-ramping resources led to changes in compensation for frequency regulation.[139]

While not an ancillary service, ramping capacity is a service for which some RTOs/ISOs have developed products. The growth of renewable generation has increased the need for generation that can increase its production rapidly to offset swings in generation or load.

Shortage Pricing

RTO/ISO markets dispatch energy and ancillary services to meet demand and reserve requirements. However, the markets may find that not enough supply is available. If the RTOs/ISOs cannot procure sufficient generation to meet demand and reserve requirements in the real-time market, they trigger shortage pricing[140] to send price signals to incentivize resources to increase the supply offered. Shortage events can be caused by unexpectedly high electric loads, supply disruptions, or both.

The common method that RTO/ISOs employ to implement shortage pricing is through the use of an operating reserve demand curve. The demand curve specifies price levels for the degree of the shortages.[141] The price of the reserves, reflecting shortage as determined by the demand curves, sets the price for ancillary services and energy.

Market Power Mitigation

RTO/ISO energy and capacity markets are typically competitive, allowing the markets to set the price. However, situations may occur that result in certain resources being essential to serving demand, thus enabling those resources to increase prices in a specific area – in other words, the ability to exercise market power. Typically, this occurs when a transmission constraint limits the amount of electricity that can flow into an area, rendering generation located inside that area essential to serving that local load. RTOs/ISOs have mechanisms for determining whether such market power may occur, and if appropriate, to mitigate the price at which affected resources may offer their supply. RTO/ISO market power mitigation typically examines whether a resource has the potential to exert market power; whether they actually offer in a way that could be an exertion of market power (conduct test); and whether any potential exertion of market power actually affected the market price (impact test).

RTO/ISO Capacity Markets and Resource Adequacy

RTO/ISOs, like other electric systems, are required to maintain adequate generation and demand-resource capacity to meet load and reliability requirements. LSEs have typically satisfied their reserve obligations with owned generation or bilateral contracts with other suppliers. In general, LSEs are required to procure sufficient capacity to meet their load. Some RTOs/ISOs also have mechanisms through which LSEs can obtain capacity commitments, such as capacity auctions and capacity payments.

Most RTOs/ISOs run a capacity market that allows LSEs to satisfy their reserve obligation. The markets cover short-term capacity, such as a month, season or year. PJM and ISO-NE run capacity auctions up to three years prior to when the capacity is needed. The capacity markets are intended to provide more certainty for investment in new capacity resources while including an opportunity for all resources to recover their fixed costs over time.

Other ISOs/RTOs, such as SPP and CAISO, rely on resource adequacy programs, in which the RTO/ISO determines the capacity each LSE is required to provide

139 Order No. 755, Frequency Regulation Compensation in the Organized Wholesale Power Markets, 137¶61,064, (October 20, 2011).

140 Order No. 825, *Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 155¶61,276 (June 16, 2016).

141 RTO/ISOs apply shortage pricing in the LMP for all intervals in which the operating software indicates that there is insufficient available energy to provide system or localized demand and reserves. *Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 825, 81 Fed. Reg. 42,882 (June 30, 2016), FERC Stats. & Regs. ¶ 31,384 (2016).

at different times of the year. These programs require each LSE to show the RTO/ISO that it has procured the required capacity for different times of the year.

Special Provisions for Essential Resource Retirements
Reliability must-run (RMR) units are generating plants that would otherwise retire but that the RTO/ISO has deemed necessary to ensure reliability. They can also be units that have market power due to their location on the grid. RTO/ISOs enter into cost-based contracts with these generating units and allocate the cost of the contract to transmission customers. In return for these payments to the generator, the RTO/ISO may call on the owner of an RMR generating unit to run the unit for grid reliability. The payment must be sufficient to pay for the cost of owning and maintaining the unit, even if it does not operate. Transmission upgrades can reduce the need for RMR units by increasing generation deliverability throughout the RTOs/ISOs.

Financial Transmission Rights

Financial transmission rights (FTRs) are contracts that give market participants an offset, or hedge, against transmission congestion costs in the day-ahead market.

FTRs were originally developed in part to give native LSEs in the nascent RTOs/ISOs price certainty similar to that available to traditional vertically integrated utilities operating in non-RTO/ISO markets. This practice continues, as FTRs are allocated to load-serving entities, transmission owners, or firm transmission right holders in RTOs/ISOs, typically based on historical usage. Entities that fund the construction of specific new transmission facilities may also be eligible to receive FTRs. The details of the allocations vary by RTO/ISO.

FTRs allow customers to protect against the risk of congestion-driven price increases in the day-ahead market in the RTOs/ISOs. Specifically, FTRs grant their holders the right to day-ahead congestion revenues over specific paths and periods of time. Congestion costs occur as the demand for scheduled power over a transmission path exceeds that path's flow capabilities. This causes the price at the source to decline or the price at the sink to increase, or both, causing the congestion cost of serving Point B from Point A to increase. By buying an FTR over the path from Point A to Point B, the FTR holder is paid the difference of the congestion price components at the sink and source, thus allowing it to hedge against the congestion costs incurred in the day-ahead market.

FTRs are acquired through allocations and purchases. Purchases take place in the RTO-administered auctions or in a secondary market. Allocations stem from a related product, the auction revenue rights (ARR). ARRs provide the firm transmission capacity holders, transmission owners or LSEs with the rights to revenue from the FTR auctions. In general, ARRs are allocated based on historical load served and, in some RTO/ISOs, ARRs can be converted to FTRs. If ARRs are converted to FTRs, the holder receives revenue from congestion. If ARRs are kept as such, the holder receives revenue from the FTR auction.

The main method for procuring FTRs is through an auction, which typically includes an annual (or multiyear) auction of one-year FTRs and monthly (or semiannual) auctions of shorter-term FTRs provided by existing FTR holders or made available by the RTO/ISO. The auctions are scheduled and run by the RTO, which requires bidding parties to post credit to cover the positions taken. FTR auction revenues are used to pay the holders of ARRs and assist the funding of future congestion payments to FTR holders. There is also a secondary market for FTRs (such as PJM's eFTR), but historically only a small number of transactions have been reported.

The quantity of FTRs made available by the RTO/ISO is bounded by the physical limits of the grid, as determined by a simultaneous feasibility test across all potential flowgates. This test is performed by the RTO/ISO prior to making FTRs available at auction and takes into account existing FTR positions and system constraints. The resulting portfolio of FTRs allocated or offered at auction represents an absolute constraint on the size of the net positions that can be held by the market. Participants in FTR auctions can procure counterflow FTRs, which directly offset prevailing flow FTR capacity, thereby allowing the

value at risk on a given path to exceed the physical limits of the line. However, such bids are physically constrained, as the net position held on the path must always conform to the simultaneous feasibility test.

FTRs can also be purchased by a creditworthy entity seeking their financial attributes as a speculative investment. In this regard, FTRs are similar to financial swaps that are executed as a contract for differences between two day-ahead LMPs (swaps are explained in Chapter 5, Trading and Capital Markets). However, FTRs are substantially different from swaps in that the quantity of FTRs is linked to physical constraints in the transmission grid, while the quantity of swaps is not. Further, FTRs are procured by allocation or FTR auction, while swaps are procured through financial over-the-counter markets or exchanges.

All six FERC-jurisdictional RTOs/ISOs trade FTRs or FTR-equivalent products. However, the types and qualities of the rights traded across the organized markets vary, as do the methods used to allocate, auction, and transfer these rights. These attributes of the FTR markets are discussed below.

Flow Type: Prevailing Flow and Counterflow. A prevailing flow FTR generally has a source in a historical generation-rich location and a sink that is in a historical load-heavy location. Alternatively, the source of a prevailing flow FTR is on the unconstrained side of a transmission interface and the sink on the constrained side. Auction clearing prices for prevailing flow FTRs are positive. Conversely, a counterflow FTR often has a source in a historical load-heavy location and a sink in a historical generation-rich location. As a result, auction clearing prices for counterflow FTRs are negative; bidders are paid to take the counterflow FTR position.

Peak Type: On-peak, Off-peak, 24-hour. FTRs can be purchased for either 16-hour on-peak blocks, 8-hour off-peak blocks or around-the-clock. Only PJM offers all three peak-type products. NYISO offers only the 24-hour product. The other RTO/ISOs offer on-peak and off-peak products.

Allocated Rights: The RTO/ISOs allocate transmission rights to transmission owners or load-serving entities within their markets. In PJM, MISO, SPP, and ISO-NE, these are allocated as auction revenue rights (ARRs), which give their holders the right to receive a share of the funds raised during the FTR auctions. CAISO allocates congestion revenue rights (CRR), which provide their holders a stream of payments based on the actual congestion occurring on associated paths. NYISO allocates both auction-based and congestion-based rights through multiple instruments. PJM and MISO allow ARR holders to convert all these rights to FTRs; NYISO allows only a portion of ARR-equivalent instruments to be converted to its version of FTRs, called Transmission Congestion Credits (TCCs). ISO-NE does not allow such conversions, while CAISO's allocation is already in a form equivalent to an FTR. Converted ARRs are fully fungible in PJM, MISO, and NYISO; CAISO only allows the sale of allocated CRRs in its secondary market, and ISO-NE has no converted instruments to sell.

Auctioned Rights: All RTOs provide FTRs (or equivalent CRRs or TCCs) for sale to the public through two or more auctions held at various times of the year. The products vary by market and by auction, with some products made available only at specific auctions.

Secondary Markets: With the exception of NYISO, each of the markets that auction FTRs also operates a bulletin board or similar venue designed to enable a secondary trading platform for FTRs. However, none of these platforms has had significant volume. NYISO offered to create a bulletin board for its participants, if requested, but received no requests.

Virtual Transactions

Virtual bids and offers (collectively, virtuals) are a form of financial trading used by market participants to hedge physical positions and by speculative traders to profit from differences between day-ahead and real-time prices. The quantity of MW purchased or sold in the day-ahead market is offset by a sale or purchase of an identical quantity of MW in the real-time, so that the net effect on the market quantity traded is zero. A virtual

trader pays (or is paid) the day-ahead price while being paid (or paying) the real-time price.

Although a trader does not have to deliver power, the transaction is not strictly financial as virtual transactions can set LMPs; the price is applied to physical as well as financial transactions. Virtual transactions can also affect the resource selection in the day-ahead market.

For each hour in the day-ahead market, virtual trades are added to the demand – day-ahead scheduled load – if virtual demand is greater than virtual supply. This has the effect of raising the price in the day-ahead market and, more importantly, increasing the amount of generation resources procured by the RTO/ISO. Since these generation resources will be available to the real-time market, the fact that virtual load does not carry forward into the real-time market will decrease the real-time demand below day-ahead scheduled load, thus placing downward pressure on real-time prices. The placement of virtuals affects the dispatch of physical capacity.

The primary benefits of virtual transactions are achieved through their financial impact on the markets. Virtuals sometimes are referred to as convergence bidding, as a competitive virtual market should theoretically cause the day-ahead and real-time prices to converge in each hour. The convergence of day-ahead and real-time prices within the RTOs/ISOs is intended to mitigate market power and improve the efficiency of serving load.

Figure 2-16: New England Independent System Operator



Source: Hitachi Energy, Velocity Suite

ISO-New England (ISO-NE)

MARKET PROFILE

ISO-NE serves the six New England states: Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. As the RTO for New England, ISO-NE is responsible for operating wholesale power markets that trade electricity, capacity, transmission congestion contracts, and related products, in addition to administering auctions for the sale of capacity.[142] ISO-NE operates the region's high-voltage transmission network and performs long-term planning for the New England system. ISO-NE operates its master control center in Holyoke, Mass.

Peak Demand

New England's all-time peak demand was 28 GW in summer 2006.[143]

Imports and Exports

ISO-NE is interconnected with the NYISO, TransEnergie (Québec), and the New Brunswick System Operator and imports around 15 percent of its annual energy needs. New England receives imports from Québec and New

142 ISO-New England Inc. Internal Market Monitor, *An Overview of New England's Wholesale Electricity Markets, A Market Primer* (June 5, 2023), https://www.iso-ne.com/static-assets/documents/2023/06/imm-markets-primer.pdf.

143 ISO New England, *Key Grid and Market Stats*, https://www.iso-ne.com/about/key-stats/.

Brunswick in most hours, and power flows in alternate directions between New England and New York, depending on market conditions.

Market Participants

The ISO-NE participants consist of end-users, IOUs, publicly owned utilities, generators, transmission owners, and financial institutions.

Membership and Governance

ISO-NE is a not-for-profit entity governed by a 10-member, independent, non-stakeholder board of directors. The sitting members of the board elect people to fill board vacancies.

NEPOOL is the principal stakeholder organization for the ISO-NE and is authorized to represent its more than 440 members in proceedings before FERC. It was organized in 1971 and its members include all the electric utilities rendering or receiving services under the ISO-NE Tariff, as well as independent power generators, marketers, load aggregators, brokers, consumer-owned utility systems, demand response providers, developers, end users, and a merchant transmission provider.

Transmission Owners

ISO-NE's largest transmission owners include:

- Central Maine Power Company
- Cross Sound Cable Company, LLC
- Emera Maine, Inc.
- Eversource Energy Service Company
- Maine Electric Power Company
- National Grid USA
- NSTAR Electric Company
- The United Illuminating Company
- VT Transco, LLC

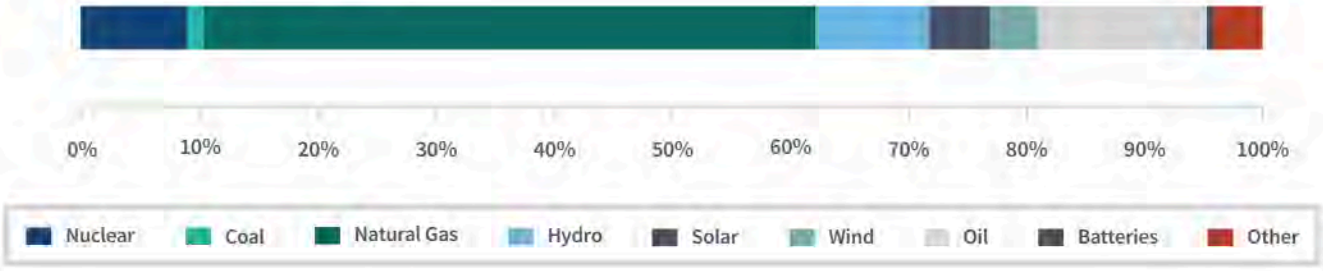
Chronic Constraints

Overall, transmission upgrades have reduced transmission constraints in ISO-NE. Constraints in ISO-NE may occur in regions affected by intermittent resources (notably wind), or by major interconnections with New Brunswick, Hydro-Quebec, and New York.[144]

Transmission Planning

Each year, ISO-NE prepares a comprehensive 10-year regional system plan (RSP) that reports on the results of ISO system planning processes. Each plan includes forecasts of future loads (the demand for electricity measured in megawatts) and addresses how this demand may be satisfied by adding supply resources; demand resources, including demand response and energy efficiency; and new or upgraded transmission facilities. The plans also summarize the region's overall needs, as well as the needs in specific areas, and includes solutions and processes required to ensure the

Figure 2-17: ISO-NE Capacity Mix



Source: EIA Form 860-M[146]

144 ISO-New England Internal Market Monitor, *2021 Annual Markets Report* (May 26, 2022), https://www.iso-ne.com/static-assets/documents/2022/05/2021-annual-markets-report.pdf.

145 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, *Preliminary Monthly Electric Generator Inventory* (based on Form EIA-860M) (February 2022), https://www.eia.gov/electricity/data/eia860m/.

reliable and economic performance of the New England power system.

Supply Resources

The total capacity in ISO-NE is over 38 GW and is predominately composed of natural gas-fired, oil-fired, and nuclear generators, as shown in the bar chart below. The region has a substantial proportion of oil-fired generation that is a particularly important resource to address potential power plant fuel shortages in the winter months during periods of local natural gas market stress.

Demand Response

ISO-NE administers the following demand-response programs for the New England wholesale electricity market:

- Real-Time Demand Response Resources (RTDR): These resources are required to respond within 30 minutes of the ISO's instructions.
- Real-Time Emergency Generation Resources that the ISO calls on to operate during a 5-percent voltage reduction that requires more than 10 minutes to implement. They must begin operating within 30 minutes of receiving a dispatch instruction.
- Transitional Price-Response Demand: An optional program that allows market participants with assets registered as RTDRs to offer load reductions in response to day-ahead LMP. The participant is paid the day-ahead LMP for the cleared interruptions, and real-time deviations are charged or credited at the real-time LMP.
- Price Responsive Demand (PRD): In June 2018, ISO New England launched a new PRD structure that fully integrates active demand resources into the regional wholesale electricity marketplace. With PRD, ISO-NE deploys its active demand resources as part of the energy dispatch and reserve-designation process along with generating resources. PRD incorporates demand response into the energy market, the reserves market and the capacity market.[146]

MARKET FEATURES

Energy Markets

ISO-NE operates day-ahead and real-time markets, generally consistent with the discussion in the RTO/ISO Features section of this report. In the real-time market, ISO-NE uses 5-minute intervals. Market participants can offer imports or request exports of electricity from neighboring control areas with at least one hour's notice throughout the day.

Ancillary and Other Services

Ancillary services, described in the Electricity Supply and Delivery section, are services that support the grid and reliability. ISO-NE procures and sets prices for ancillary services in the real-time and forward reserve markets.

Market Power Mitigation

In ISO-NE, market power mitigation is applied for physical withholding, economic withholding, uneconomic production, certain types of virtual transactions and other conduct, if the activity has a material effect on prices or uplift payments. The market monitor uses defined thresholds to identify physical and economic withholding and uneconomic generation. Additionally, defined thresholds determine whether bids and offers would, if not mitigated, cause a material effect on LMPs or uplift charges.

Capacity Markets

ISO-NE's capacity market is termed the Forward Capacity Market (FCM). The FCM includes annual Forward Capacity Auctions (FCA) where both generator and demand resources offer capacity three years in advance of the period for which capacity will be supplied. The three-year lead time is intended to encourage new resource entry by affording market participants additional time to plan and make decisions relative to the forward market prices. Resources whose capacity clears the FCA acquire capacity supply obligations (CSOs). ISO-NE held its first two FCAs in 2008 for the 2010-11 and 2011-12 delivery years. The first full year of

146 ISO-NE, *Price-responsive demand explained: Q&A with Henry Yoshimura, ISO Director of Demand Resource Strategy* (June 6, 2018), http://isonewswire.com/updates/2018/6/6/price-responsive-demand-explained-qa-with-henry-yoshimura-is.html.

capacity market commitments began on June 1, 2010. The FCA process includes the modeling of transmission constraints to determine if load zones will be import- or export-constrained.

The FCM includes rules known as Pay-for-Performance, which mandate performance-based financial incentives for capacity resources during times of system stress.[147] Under Pay-For-Performance, resource owners are subject to charges or incentive payments, based on performance during shortage conditions. Those resources unable to fulfill their CSOs are penalized and compensate the overperforming resources that relieve the capacity shortfall. ISO-NE additionally requires the owners of capacity resources to offer into the day-ahead and real-time energy markets.

Special Provisions for Essential Resource Retirements

When a resource owner requests to withdraw from the capacity market (termed a delist bid) or to retire the resource (termed a non-price retirement request), the ISO evaluates whether the resource is needed for reliability, such as when a resource's withdrawal could lead to a violation of a reliability requirement, such as inadequate reserve margins or a loss of electric system stability.

In New England, the resource owner has the option to retire the unit or continue to operate it while the ISO works with regional stakeholders to find alternate supply or engineering solutions that could allow the resource to retire and still maintain grid reliability. Alternative solutions might include obtaining emergency sources of generation or more expensive generation from outside the region. If no other alternative is available, the ISO may compensate the unit through certain payment provisions of the capacity market or by entering into a cost-of-service agreement with the resource owner while other options are pursued.

Financial Transmission Rights

New England FTRs are monthly and annual products that provide market participants with a means to offset or hedge against transmission congestion costs in the day-ahead energy market. An FTR is an instrument that entitles the FTR holder to a payment for costs that arise with transmission congestion over a selected path, or source-and-sink pairs of locations on the grid. The FTR also requires its holder to pay a charge for those hours when congestion occurs in the opposite direction of the selected source-and-sink pair. The RTO holds FTR auctions to allow market participants the opportunity to acquire FTRs or to sell FTRs they currently hold. In New England, ARRs represent the right to receive revenues from the FTR auctions. ISO-NE allocates ARRs to both LSEs, in relation to historical load, and to entities who make transmission upgrades that increase the capability of the transmission system.

Virtual Transactions

New England's market includes a virtual transaction feature, as generally described in the Virtual Transactions part of the RTO/ISO Features section.

Credit Requirements

ISO-NE's tariff includes credit requirements for participants that assist in mitigating the potential effects of defaults that would otherwise be borne among all market participants. ISO-NE assesses and calculates the required credit dollar amounts for the segments of the market in which an entity requests to participate. ISO-NE then establishes a credit limit for each market participant in accordance with tariff formulas that include various creditworthiness-related specifications, such as tangible net worth and total amounts due to the ISO-NE market.

147 ISO-NE's Pay-For-Performance rules became effective June 1, 2018, for Forward Capacity Auction 9. ISO-NE, Internal Market Monitor, *2017 Annual Markets Report*, at 138 (2018), https://www.iso-ne.com/static-assets/documents/2018/05/2017-annual-markets-report.pdf.

Figure 2-18: New York Independent System Operator



Source: Hitachi Energy, Velocity Suite

New York Independent System Operator (NYISO)

MARKET PROFILE

The NYISO footprint covers the entire state of New York. Prior to restructuring of the electric industry in the 1990s, New York's private utilities and public power authorities owned and operated New York's electric system. Operation of the electric grid was coordinated by a voluntary collaboration of the utilities and power authorities known as the New York Power Pool (NYPP). The creation of the NYISO was authorized by FERC in 1998. The formal transfer of the NYPP's responsibilities to the NYISO took place on Dec. 1, 1999. NYISO operates its system from control centers in Rensselaer, NY, and Guilderland, NY.

NYISO is responsible for operating wholesale power markets that trade electricity, capacity, transmission congestion contracts, and related products, in addition to administering auctions for the sale of capacity. NYISO operates New York's high-voltage transmission network and performs long-term planning. NYISO also serves as the reliability coordinator for its footprint.

Peak Demand

NYISO's all-time peak demand was 34 GW in summer 2013.[148]

Imports and Exports

NYISO imports and exports energy through interconnections with ISO-NE, PJM, TransEnergie (Quebec) and Ontario.

Market Participants

NYISO's market participants include generators, transmission owners, financial institutions, traditional local utilities, electric co-ops, and industrials.

Membership and Governance

NYISO is governed by an independent 10-member board of directors, ISO management, and the business issues and operating committees. Each committee oversees its own set of working groups or subcommittees. These committees comprise transmission owners, generation owners and other suppliers, consumers, public power, and environmental entities. Tariff revisions on market rules and operating procedures filed with FERC are largely developed through consensus by these committees. The members of the board, as well as all employees, must not be directly associated with any market participant or stakeholder.

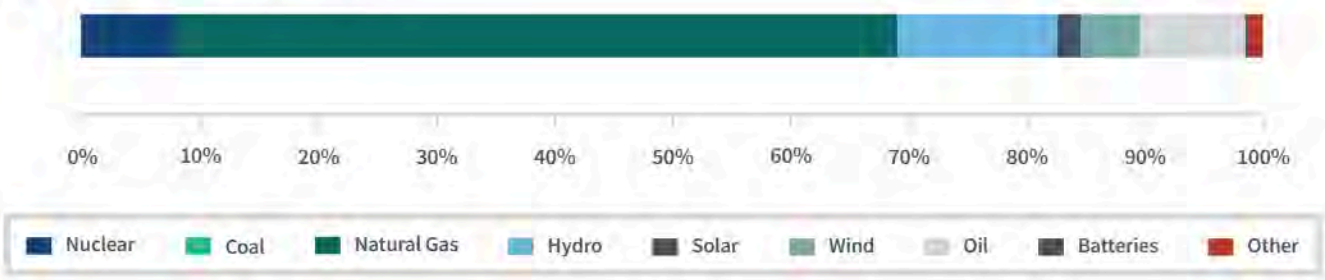
Transmission Owners

NYISO's largest transmission owners include:

- Central Hudson Gas & Electric Corp.
- Consolidated Edison Co. of New York
- Long Island Power Authority (LIPA)

148 New York Independent System Operator, Gold Book, *2022 Load & Capacity Data Report 67* (April 2022), https://www.nyiso.com/documents/20142/2226333/2022-Gold-Book-Final-Public.pdf/cd2fb218-fd1e-8428-7f19-df3e0cf4df3e.pdf.

Figure 2-19: NYISO Capacity Mix



Source: EIA Form 860-M[150]

- New York Power Authority (NYPA)
- New York State Electric and Gas Corp. (NYSEG)
- National Grid
- Orange & Rockland Utilities
- Rochester Gas and Electric Corp.

Chronic Constraints

The chronic transmission constraints in NYISO are in the southeastern portion of the state, leading into New York City and Long Island. As a result of their dense populations, New York City and Long Island are the largest consumers of electricity. Consequently, energy flows from the west and the north towards these two large markets, frequently requiring transmission facilities to operate near their limits. This results in transmission constraints in several key areas, often resulting in higher prices in the New York City and Long Island markets.

Transmission Planning

NYISO conducts a biennial transmission planning process with stakeholders that includes both short-term and long-term projects as part of its Comprehensive System Planning Process. This work evaluates the adequacy and security of the bulk power system in New York over a ten-year study period. Reliability needs are addressed through the development of a reliability plan. Planning focuses on congestion on the bulk power system and possible projects to alleviate the congestion.

A component of NYISO's transmission planning includes evaluating proposals to meet transmission needs driven by public policy requirements identified by the New York Public Service Commission.

Supply Resources

The total capacity in NYISO is over 43 GW and is predominately composed of natural gas-fired, hydroelectric, nuclear and oil-fired generators, as shown in the bar chart below. The region's hydroelectric capacity is particularly important and includes the Niagara Falls and St. Lawrence facilities.

Demand Response

NYISO has four demand-response programs: the emergency demand-response program (EDRP), the installed capacity (ICAP) special case resources program (SCR), the Day-Ahead Demand-Response Program (DADRP) and the Demand-Side Ancillary Services Program (DSASP).

Both the emergency and special case programs can be deployed in energy shortage situations to maintain the reliability of the bulk power grid. The participants in these programs are paid by NYISO for reducing energy consumption when asked to do so and reductions are voluntary for EDRP participants.However, SCR participants are required to reduce power usage as part of their agreement and are compensated for this obligation.

149 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M)* (February 2022), https://www.eia.gov/electricity/data/eia860m/.

NYISO's DADRP program allows energy users to bid their load reductions into the day-ahead market and offers that are determined to be economic are paid the market clearing price. Under day-ahead demand-response, flexible loads may effectively increase the amount of supply in the market and moderate prices.

The DSASP provides retail customers that can meet telemetry and other qualifications with the ability to bid their load curtailment capability into either the day-ahead market or real-time market to provide reserves and regulation service. Accepted offers are paid the market clearing price for the supplied reserves or regulation services.

MARKET FEATURES

Energy Markets

NYISO operates day-ahead and real-time markets, generally consistent with the discussion in the RTO/ISO Features section of this report. In the real-time market, NYISO uses 5-minute intervals. Market participants can offer imports or request exports of electricity from neighboring control areas with at least one hour's notice throughout the day. NYISO refers to LMPs as locational-based marginal prices, or LBMPs.

NYISO's real-time market also offers an hour-ahead feature. The hour-ahead market allows buyers and sellers of electricity to balance unexpected increases or decreases of electricity consumption after the day-ahead market closes. Bids and offers are submitted an hour ahead of time and prices are set based on those bids and offers, generally for use in matching generation and load requirements, but those prices are advisory only. Hour-ahead scheduling is completed at least 45 minutes prior to the beginning of the dispatch hour after NYISO reviews transmission outages, the load forecast, reserve requirements and hour-ahead generation and firm transaction bids, among other things.

Ancillary and Other Services

NYISO co-optimizes ancillary services with the energy through its markets. Operating reserves and regulation are typically provided by generators, but NYISO also allows demand-side providers to participate in these markets.

Ancillary services are those functions performed by electric generating, transmission and system-control equipment to support the transmission of electric power from generating resources to load. RTOs procure or direct the supply of ancillary services to maintain the reliability of the transmission system.

Market Power Mitigation

ISO-NE conducts automatic market power mitigation in its day-ahead and real-time markets. This automated mitigation performs conduct and impact tests and applies mitigation where it deems appropriate. The categories of conduct that may warrant mitigation by NYISO include physical withholding, economic withholding, and uneconomic production by a generator or transmission facility to obtain benefits from a transmission constraint. NYISO does not impose mitigation unless the conduct causes or contributes to a material change in prices, or substantially increases guarantee payments to participants.

Generators in New York City are subject to automated market power mitigation procedures because New York City is frequently separated by transmission congestion from other parts of New York. Additionally, generators in New York City have been deemed to have market power. These automated procedures determine whether any day-ahead or real-time energy bids, including start-up cost bids and minimum generation bids, but excluding ancillary services bids, exceed the tariff's thresholds for economic withholding. The protocols also determine whether such bids would cause material price effects or changes in guaranteed payments. If these two tests are met, mitigation is imposed automatically, and the applicable reference level is substituted for the entity's actual bid to determine the clearing price.

Capacity Markets

NYISO's capacity market requires LSEs to procure capacity through installed-capacity (ICAP) auctions, self-supply or bilateral arrangements based on their forecasted peak

load plus a margin. New York has capacity requirements for four zones: New York City, Long Island, Lower Hudson Valley, and New York-Rest of State. NYISO conducts auctions for three time periods: the capability period auction (covering six months), the monthly auction and the spot market auction. The resource requirements do not change in the monthly auctions and spot market auctions relative to the capability period auction. The shorter monthly auctions are designed to account for incremental changes in LSEs' load forecasts.

Under the NYISO capacity auction rules, entities that offer capacity into an auction that is subsequently purchased by load are required to offer that amount of capacity into the day-ahead energy market. This rule ensures that capacity sold through the capacity auctions is actually delivered into the market.

Capacity for New York City is subject to offer caps and floors. Offer caps in New York City are based on the projected clearing price for capacity in the spot market.[150] Capacity from generators within New York City must be offered in each ICAP spot market auction, unless that capacity has been exported out of New York or sold to meet ICAP requirements outside New York City.[151]

Special Provisions for Essential Resource Retirements

Generation owners within New York that seek to retire or suspend a generator must first obtain approval from state regulators. After an assessment, if the generator is found to be necessary for reliability purposes, the local transmission owner can be compelled to reach a contract with the generator that includes compensation to support continued operation of the plant until the reliability need is resolved.

Financial Transmission Rights

The NYISO refers to FTRs as Transmission Congestion Contracts (TCCs). A TCC is an instrument that entitles the holder to a payment for the costs that arise with transmission congestion over a selected path, or source-and-sink pair of locations (or nodes) on the grid. The TCC also requires its holder to pay a charge for those hours when congestion is in the opposite direction of the selected source-and-sink pair. The payment, or charges, are calculated relative to the difference in congestion prices in the day-ahead market across the specified FTR transmission path.

Virtual Transactions

NYISO's market includes a virtual transaction feature that allows a participant to buy or sell power in the day-ahead market without requiring physical generation or load. Virtual trading in NYISO takes place on a zonal level, not a nodal level.

Credit Requirements

NYISO's tariff includes credit requirements that assist in mitigating the effects of defaults that would otherwise be borne among all market participants. NYISO assesses and calculates the required credit dollar amounts for the segments of the market in which an entity requests to participate. The market participant may request an unsecured credit allowance subject to certain restrictions. NYISO must review the entity's request relative to various creditworthiness-related specifications such as investment grade or equivalency rating and payment history.

150 New York Independent System Operator, Inc., NYISO *MST - Market Administration and Control Area Services Tariff (MST) - 23MST Att H - ISO Market Power Mitigation Measures - 23.2 MST Att H Conduct Warranting Mitigation at 625* (accessed October 6, 2022), https://nyisoviewer.etariff.biz/ViewerDocLibrary/MasterTariffs/9FullTariffNYISOMST.pdf; New York Independent System Operator, Inc., *NYISO MST - Market Administration and Control Area Services Tariff (MST) - 23 MST Att H - ISO Market Power Mitigation Measures - 23.4.5 MST Att Installed Capacity Market Mitigation Measures - 23.4.5.2 MST Att H at 705* (accessed October 6, 2022), https://nyisoviewer.etariff.biz/ViewerDocLibrary/MasterTariffs/9FullTariffNYISOMST.pdf.

151 New York Independent System Operator, Inc., *NYISO MST - Market Administration and Control Area Services Tariff (MST) - 23 MST Att H - ISO Market Power Mitigation Measures - 23.4.5 MST Att Installed Capacity Market Mitigation Measures - 23.4.5.4 MST Att H* at 708 (accessed October 6, 2022), https://nyisoviewer.etariff.biz/ViewerDocLibrary/MasterTariffs/9FullTariffNYISOMST.pdf.

PJM

MARKET PROFILE

PJM centrally dispatches generation and coordinates the movement of wholesale electricity in all or part of 13 states (Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia and West Virginia) and the District of Columbia. PJM operates two fully functional dispatch centers at Valley Forge and Milford, Pennsylvania. The control rooms operate simultaneously with parallel operations. PJM operates a competitive wholesale electricity market and manages the reliability of its transmission grid. PJM provides open access to the transmission system it manages and performs long-term planning. PJM's markets include energy (day-ahead and real-time), capacity and ancillary services.

PJM was founded in 1927 as a power pool of three utilities serving customers in Pennsylvania and New Jersey. In 1956, with the addition of two Maryland utilities, it became the Pennsylvania-New Jersey-Maryland Interconnection, or PJM. PJM became a fully functioning ISO in 1996 and, in 1997, it introduced markets with bid-based pricing and locational market pricing. PJM was designated an RTO in 2001.

Peak Demand

PJM's all-time peak demand was 165.6 GW in summer 2006.[152]

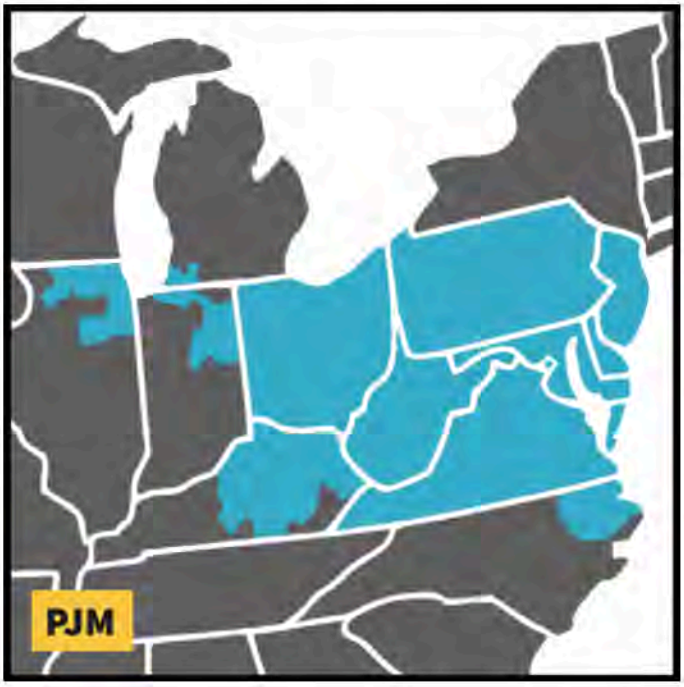
Imports and Exports

PJM has interconnections with MISO and the NYISO. PJM also has direct interconnections with TVA, Progress Energy Carolinas and the VACAR, among other systems. PJM market participants import energy from, and export energy to, external regions continuously. PJM is a primarily a net exporter of electricity, but occasionally is a net importer during periods of system stress.

Market Participants

PJM's market participants include power generators, transmission owners, electric distributors, power marketers, large consumers, and financial traders.

Figure 2-20: The PJM Interconnection



Source: Hitachi Energy, Velocity Suite

Membership and Governance

PJM has a two-tiered governance model consisting of a board of managers and the members committee. PJM is governed by a 10-member board, nine of whom PJM members elect. The board appoints the tenth, the president and CEO, to supervise day-to-day operations. The board is generally responsible for oversight of system reliability, operating efficiency and short- and long-term planning. The board ensures that no member or group of members exerts undue influence. The members committee, which advises the board, is composed of five voting sectors representing power generators, transmission owners, electric distributors, power marketers and large consumers.

Transmission Owners

PJM transmission owners eligible to vote in PJM

152 PJM Interconnection, PJM 2021 *Annual Report, Summer Performance by the Numbers*, https://services.pjm.com/annualreport2021/operations/.

stakeholder proceedings include:

- Appalachian Power Company, AEP Subsidiary[153]
- AMP Transmission, LLC
- Dayton Power & Light Company, AES Subsidiary
- Duke Energy Business Services, LLC[154]
- Duquesne Light Company
- East Kentucky Power Cooperative, Inc.
- Exelon Business Services Company, LLC[155]
- ITC Interconnection LLC
- Linden VFT LLC
- Monongahela Power d/b/a Allegheny Power, First Energy Subsidiary [156]
- Neptune Regional Transmission System, LLC[157]
- PPL Electric Utilities Corporation, d/b/a PPL Utilities[158]
- Public Service Electric and Gas Company
- Rockland Electric Company
- Virginia Electric and Power Company

Chronic Constraints

The most severe constraints occur on 230 kV transmission facilities moving power south from Pennsylvania and New Jersey to Maryland, Delaware, and Virginia. Local congestion also occurs on low-voltage lines near load centers in northern Illinois, New Jersey, eastern Pennsylvania, central and eastern Maryland, northern Virginia, the District of Columbia, and Delaware.

Transmission Planning

PJM's Regional Transmission Expansion Plan identifies transmission system additions and improvements needed to keep electricity flowing within PJM. Studies are conducted to test the transmission system against national and regional reliability standards. These studies look forward to identify future transmission overloads, voltage limitations, and other reliability standards violations. PJM then develops transmission plans to resolve violations that could otherwise lead to overloads and blackouts.

Supply Resources

The total capacity in PJM is over 219 GW and is predominately comprised of natural gas, coal, and nuclear generators, as shown in the bar chart below. Much of PJM's gas-fired capacity is located near the Marcellus and Utica shale formations. Of note, 40.6 gigawatts of coal-fired capacity are projected to retire in PJM between 2011 and 2026.[159]

Demand Response

End-use customers providing demand response have the opportunity to participate in PJM's energy, capacity, synchronized reserve, and regulation markets. PJM's demand response programs can be grouped into emergency or economic programs. The emergency program compensates end-use customers who reduce their usage during emergency conditions on the PJM system. Participation in the emergency program may be voluntary or mandatory and payments may include energy payments, capacity payments or both.

The economic program allows end-use customers to reduce electricity consumption in the energy markets and receive a payment when LMPs are high. Under this program, all hours are eligible and all participation is voluntary. Participation in the program takes three forms: submitting an offer into the day-ahead market

153 Transmission Companies represented: AEP Appalachian Transmission, AEP Energy Partners, AEP Energy, AEP Indiana Michigan Transmission, AEP Kentucky Transmission, AEP Ohio Transmission, AEP West Virginia Transmission, Appalachian Power, Indiana Michigan Power, Kentucky Power, Kingsport Power, Ohio Power, Ohio Valley Electric, PATH West Virginia Transmission, Transource Energy, Wheeling Power.

154 Transmission Companies represented: Duke Energy Kentucky, Duke Energy Ohio.

155 Transmission Companies represented: Commonwealth Edison, PECO Energy, Baltimore Gas and Electric.

156 Transmission Companies represented: American Transmission Systems, Jersey Central Power & Light, Mid-Atlantic Interstate Transmission, PATH Allegheny Transmission, Potomac Edison, Trans-Allegheny Interstate Line, West Penn Power.

157 Transmission Companies represented: Hudson Transmission Partners.

158 Transmission companies represented: Louisville Gas and Electric, Kentucky Utilities.

159 Monitoring Analytics, *2022 Quarterly State of the Market Report, January Through June*, Section 12, p. 673 (https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2022/2022q2-som-pjm-sec12.pdf).

Figure 2-21: PJM Capacity Mix



Source: EIA Form 860-M[161]

that clears; submitting an offer into the real-time market that is dispatched; and self-scheduling load reductions while providing notification to PJM. End-use customers participate in demand response in PJM through members called curtailment service providers who act as agents for the customers. Curtailment service providers aggregate the demand of retail customers, register that demand with PJM, submit the verification of demand reductions for payment by PJM and receive the payment from PJM.

MARKET FEATURES

Energy Markets

Energy Markets: PJM operates day-ahead and real-time markets, generally consistent with the discussion in the RTO/ISO Features section of this report. In the real-time market, PJM uses 5-minute intervals. Generators that are available but not selected in the day-ahead scheduling may alter their offers for use in the real-time market during the generation rebidding period from 4 p.m. to 6 p.m.; otherwise, their original day-ahead market offers remain in effect for the real-time market.

Ancillary and Other Services

Ancillary services, described in the Electricity Supply and Delivery section, are services that support the grid and reliability. PJM procures most ancillary services via its energy markets. Blackstart service and reactive power are compensated on a cost-of-service basis.

Market Power Mitigation

PJM caps offers for any hour in which there are three or fewer generation suppliers available for redispatch that are jointly pivotal, meaning they have the ability to increase the market price above the competitive level. This is called the Three Pivotal Supplier Test. When this occurs, generator offers are adjusted to price levels reflecting short-run marginal cost.

Capacity Markets

PJM's capacity market is called the Reliability Pricing Model (RPM). The RPM market was implemented in 2007 and is designed to ensure the future availability of capacity resources, including demand-resources and energy-efficiency resources that will be needed to keep the regional power grid operating reliably. The RPM market design is based on three-year, forward-looking annual obligations for locational capacity, under which supply offers are cleared against a downward-sloping demand curve, called the variable resource requirement (VRR) curve. The VRR curve establishes the amount of capacity that PJM requires its LSE customers to purchase, and the price for that capacity, in each capacity zone (locational deliverability area or LDA). Under RPM, when an LDA is transmission-constrained in the auction (limited in the amount of generation that can be imported into those areas), capacity prices generally rise in that area relative to the overall PJM footprint.

160 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M)* (released February 2022), https://www.eia.gov/electricity/data/eia860m/.

Annual auctions are referred to as Base Residual Auctions (BRA). LSEs that are able to fully supply their own capacity needs can choose not to participate in the auctions. The largest amounts of capacity in PJM are procured through the BRA, with lesser quantities procured through self-supply and contracted (bilateral) resources.

Market power mitigation in PJM's capacity market includes rules delineating a must-offer requirement, offer caps, minimum offer prices, exceptions for competitive entry, among others. Demand resources and energy efficiency resources may be offered into RPM auctions and receive the clearing price without mitigation.

Specific RPM rules, termed Capacity Performance, provide performance incentives for power plants, demand response, and energy efficiency resources to provide electricity at peak demand regardless of extreme weather events and system emergencies. Capacity Performance rules provide performance bonus payments for resources that over-perform during system emergencies, and severe financial penalties for resources that do not perform during such events.

Existing generation that qualifies as a capacity resource must be offered into RPM auctions, except for resources owned by entities that elect the fixed resource requirement option. The fixed resource option allows LSEs to meet their supply obligation outside PJM's capacity market, using, for example, resources they own.[161] Intermittent and capacity storage resources, including hydro, and demand response and energy efficiency, are also exempt from must-offer requirements. An administratively determined demand curve defines scarcity pricing levels and, with the supply curve derived from capacity offers, determines market prices in each BRA. Participation by load-serving entities is mandatory, except for those entities that elect the fixed resource requirement option. Also, any generator that has a commitment from the capacity market must submit an offer into the day-ahead energy market.

Special Provisions for Essential Resource Retirements

A generator owner who wishes to retire a unit must request permission from PJM to deactivate the unit at least 90 days in advance of the planned date. The request includes an estimate of the amount of project investment necessary to keep the unit in operation. PJM, in turn, analyzes if the retirement would lead to a reliability issue. Additionally, PJM estimates the period of time it would take to complete transmission upgrades necessary to alleviate the reliability issue.

If PJM requests the unit to operate past the desired deactivation date, the generator owner may file with FERC for cost recovery associated with operating the unit until it may be deactivated. Alternatively, the owner may choose to receive avoided cost compensation calculated according to PJM's tariff.

Financial Transmission Rights

PJM conducts auctions for selling and buying FTRs made available for the PJM transmission system. Proceeds from the auctions are paid to Auction Revenue Right (ARR) holders, where the ARRs are allocated to firm transmission service customers. PJM conducts its auctions on a long-term, annual, and monthly basis. In PJM, market participants are able to acquire financial transmission rights in the form of options or obligations. The RTO includes a secondary market for its FTRs, which facilitates bilateral trading of existing FTRs between PJM members through an internet-based computer application.

Virtual Transactions

PJM's market includes a virtual transaction feature that allows a participant to buy or sell power in the day-ahead market without requiring physical generation or load. In addition to the types of transaction discussed above, PJM offers Up to Congestion (UTC) transactions, a spread bid. In a UTC transaction, a market participant submits an offer to simultaneously inject energy at a specified source and withdraw the same megawatt

161 PJM, *Securing Fixed Resources*, (accessed December 2, 2022), https://pjm.com/-/media/about-pjm/newsroom/fact-sheets/securing-resources-through-fixed-resource-requirement-fact-sheet.ashx.

quantity at a specified sink in the day-ahead marketand specifies the maximum difference in locational marginal prices (LMP) at the transaction's source and sink that the market participant is willing to pay. PJM accepts the bid if the day-ahead LMP differential, i.e., the difference in day-ahead LMPs at the sink and the source, does not exceed the participant's UTC transaction bid. UTC positions are liquidated in the real-time energy market.

Credit Requirements

PJM's tariff includes credit requirements that a market participant needs to meet in order to participate in the market. The credit requirements assist in mitigating the effects of defaults that would otherwise be borne among all market participants. The RTO assesses and calculates the required credit amounts for the segments of the market in which an entity requests to participate. The market participant may request an unsecured credit allowance subject to certain restrictions. The RTO must review the entity's request relative to various creditworthiness-related specifications such as tangible net worth and credit scores.

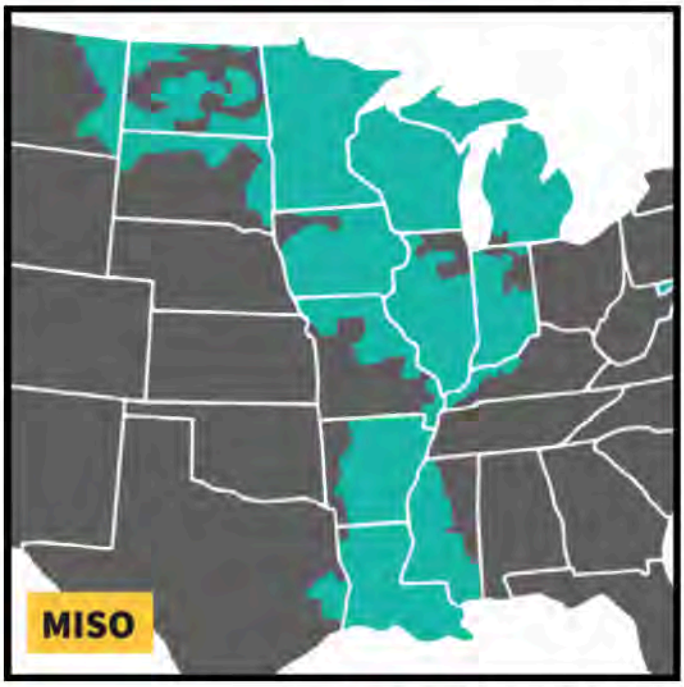
Midcontinent Independent System Operator (MISO)

MARKET PROFILE

MISO operates the transmission system and a centrally dispatched market in portions of 15 states in the Midwest and the South, extending from Michigan and Indiana to Montana and from the Canadian border to the southern areas of Louisiana and Mississippi. The system is operated from three control centers: Carmel, Indiana; Eagan, Minnesota; and Little Rock, Arkansas. MISO also serves as the reliability coordinator for additional systems outsideof its market area, primarily to the north and northwest of the market footprint.

MISO was not a power pool before organizing as an ISO in December 2001. It began market operations in April 2005.

Figure 2-22: Midcontinent Independent System Operator



Source: Hitachi Energy, Velocity Suite

In January 2009, MISO implemented a market redesign that added auctioned and optimized ancillary services along with energy. As part of the market update, MISO combined its 24 separate balancing areas into a single balancing area. In 2013, the RTO began operations in the MISO South region, including the utility footprints of Entergy, Cleco, and South Mississippi Electric Power Association, among others, in parts of Arkansas, Mississippi, Louisiana, and Texas.

Peak Demand

MISO's all-time peak demand was 127 GW in summer 2011.[162]

Imports and Exports

MISO has interconnections with the PJM and SPP RTOs. It is also directly connected to Southern Company, TVA, the electric systems of Manitoba and Ontario, and several smaller systems. MISO is a net importer of power overall, but the interchange with some areas can flow

162 MISO, Corporate Fact Sheet, at 1 (June 2022), https://www.misoenergy.org/about/media-center/corporate-fact-sheet.

in either direction, depending on the relative loads and prices in the adjoining regions. Manitoba Hydro supplies a large part of MISO's load with its excess capacity, particularly in the summer.

Market Participants

MISO includes approximately 56 transmission owners, whose assets define the MISO market area. MISO's market participants include generators, power marketers, transmission-dependent utilities and load-serving entities.[163]

Membership and Governance

An independent board of directors of ten members, including the CEO, governs MISO. Directors are elected by the MISO membership from candidates provided by the board.[164]

MISO relies upon a stakeholder process that works to find collaborative solutions to problems faced by the RTO. These entities have an interest in MISO's peration and include state regulators, consumer advocates, transmission owners, independent power producers, power marketers and brokers, municipal and cooperative utilities and large-volume customers.

Transmission Owners

MISO's largest transmission owners include:

- American Transmission Co.
- Ameren (Missouri and Illinois)
- American Transmission Systems
- Duke
- Cleco
- Entergy
- Indianapolis Power and Light
- ITC
- Michigan Public Power Agency
- NSP Companies (Xcel)
- Northern Indiana Public Service Co.
- Otter Tail Power
- MidAmerican Energy

Chronic Constraints

MISO has certain pathways that are more likely to become congested, but the likelihood and pattern of congestion in any area is subject to weather patterns, wind production, and interchange with external regions. When load is high in the eastern part of MISO and to the east in PJM, constraints occur on pathways from the Minnesota and Wisconsin areas through Chicago and across Indiana. A particular congestion point with this pattern is northern Indiana. When colder weather occurs in Minnesota and the Dakotas, there is often congestion in the northern direction, particularly in Iowa. Higher wind production can cause localized constraints in some areas and can cause congestion in pathways from southern Minnesota and western Iowa moving eastward. New Orleans and East Texas are two constrained areas in MISO South. Additionally, constraints frequently arise between MISO Midwest and MISO South.

Transmission Planning

The main vehicle MISO uses for transmission planning is the MISO Transmission Expansion Plan developed by the MISO planning department in collaboration with transmission owners and other stakeholders who form the planning advisory committee. The plan is updated annually. Once approved by the board, the plan becomes the responsibility of the transmission owners.

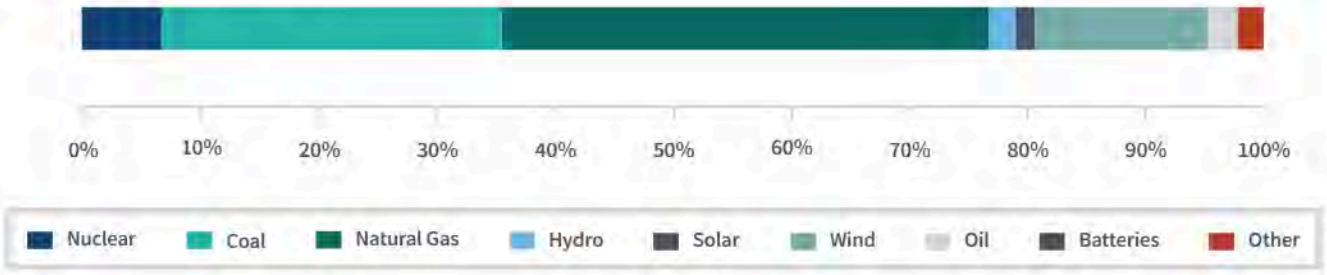
Supply Resources

The total capacity in MISO is over 197 GW and is predominately composed of coal and natural gas-fired generators, providing roughly 70 percent of the total capacity combined, as shown in the bar chart below. Nuclear and wind are also important resources for the region.

163 *Id.*

164 MISO, *Principals of Corporate Governance*, at 3, https://cdn.misoenergy.org/Principles%20of%20Corporate%20Governance110859.pdf.

Figure 2-23: MISO Capacity Mix



Source: EIA Form 860-M[165]

Demand Response

MISO has more than 12.2 GW of demand response resources, including behind-the-meter generation. A number of these resources are operated through local utility programs and are not under the direct control of MISO. MISO has provisions allowing demand-side resources to participate in the energy and reserve markets, but participation is a small part of demand response. Some of the demand response under MISO's direct control is only available under emergency conditions.[166]

MARKET FEATURES

Energy Markets

MISO operates day-ahead and real-time markets, generally consistent with the discussion in the RTO/ISO Features section of this report. MISO's real-time market operates for 5-minutes intervals.

Ancillary and Other Services

Ancillary services, described in the Electricity Supply and Delivery section, are services that support the grid and reliability. MISO procures ancillary services via the co-optimized energy and ancillary services market.

In addition to ancillary services, MISO has implemented a ramping product that provides capacity that can increase output rapidly to help offset shifts in generation or load, known as the Ramp Capability Product (RCP).

Market Power Mitigation

When congestion occurs, there may be limits on the number of generators that can satisfy load in some areas, so that they may be able to exercise market power. In response, MISO may impose mitigation for those generators whose offers are significantly higher than their costs and have a significant impact on one or more LMPs. When these conditions are met, MISO reduces the generator's offer to an offer that is consistent with a competitive result.

Capacity Markets

MISO maintains an annual capacity requirement on all LSEs based on the load forecast plus reserves. LSEs are required to specify to MISO what physical capacity, including demand-side resources, they have designated to meet their load forecast. This capacity can be acquired either through an annual capacity auction, bilateral purchase, or self-supply. For the capacity market, MISO is divided into 10 zones whose forecast demand must be met by internal generation, demand-side resources, or deliverable external capacity.

165 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M)* (released February 2022), https://www.eia.gov/electricity/data/eia860m/.

166 Potomac Economics, *2021 State of the Market Report for the MISO Electricity Markets,* at 100 (June 2022), https://www.potomaceconomics.com/wp-content/uploads/2022/06/2021-MISO-SOM_Report_Body_Final.pdf.

Resources used to meet LSEs' annual capacity requirements must offer that capacity into MISO's energy markets and, when qualified, into the ancillary services markets, for each hour of each day for the entire planning year. Must-offer requirements support MISO's mitigation process by providing an objective measure with which to identify physical withholding.

Special Provisions for Essential Resource Retirements

Power plant owners that seek to retire or suspend a generator must first obtain approval from MISO. The RTO evaluates plant retirement or suspension requests against reliability needs, and System Support Resource (SSR) designations are made where reliability is threatened. Once an agreement has been reached, SSRs receive compensation associated with remaining online and available.

Financial Transmission Rights

MISO holds FTR auctions to allow market participants the opportunity to acquire FTRs, sell FTRs that they currently hold, or to convert ARRs to FTRs. ARRs provide LSEs, and entities who make transmission upgrades, with a share of the revenues generated in the FTR auctions. MISO allocates ARRs to transmission customers relative to historical usage, or upgraded capability, of the transmission system. MISO FTRs are monthly and annual products.

Virtual Transactions

MISO's market includes a virtual transaction feature that allows a participant to buy or sell power in the day-ahead market without requiring physical generation or load. Virtual transactions allow for more participation in the day-ahead, price-setting process, allow participants to manage risk, and promote price convergence between the day-ahead and real-time markets.

These transactions are a component of the day-ahead market where the bids and offers are included in the determination of the LMP along with physical resource offers and actual load bids. Market participants, whose virtual transactions clear in the day-ahead market, have their positions cleared in the real-time market at the real-time price. Virtual bids and offers are allowed in MISO at any pricing node or aggregate of pricing nodes.

Credit Requirements

MISO's tariff includes credit requirements that a market participant needs to meet in order to participate in the market. The credit requirements assist in mitigating the effects of defaults that would otherwise be borne among all market participants. The RTO assesses and calculates the required credit dollar amounts for the segments of the market in which an entity requests to participate. The market participant may request an unsecured credit allowance subject to certain restrictions. The RTO must review the entity's request relative to various creditworthiness-related specifications such as tangible net worth and credit scores.

Southwest Power Pool (SPP)

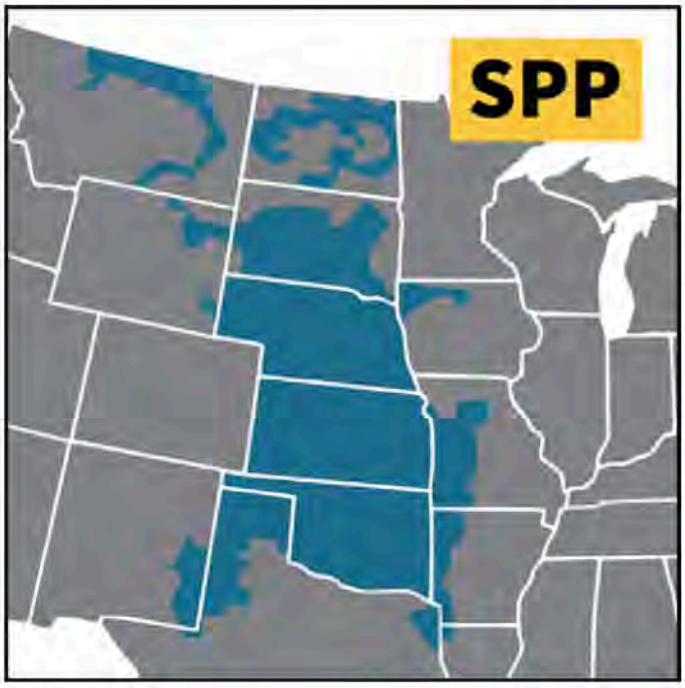
MARKET PROFILE

SPP's RTO manages transmission in fourteen states: Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. Founded as an 11-member tight power pool in 1941, SPP achieved RTO status in 2004, ensuring reliable power supplies, adequate transmission infrastructure, and competitive wholesale electricity prices for its members. SPP operates through its control center in Little Rock, Ar.

SPP began operating its real-time Energy Imbalance Service (EIS) market in 2007. In the same year, SPP became a FERC-approved Regional Entity. The SPP Regional Entity serves as the reliability coordinator for the NERC region, overseeing compliance with reliability standards.

SPP implemented its Integrated Marketplace in March 2014 which includes a day-ahead energy market, a real-time energy market, and an operating reserve market. SPP's Integrated Marketplace also includes a market for Transmission Congestion Rights. The SPP Integrated Marketplace co-optimizes the deployment of energy and operating reserves to dispatch resources on a least-cost basis.

Figure 2-24: Southwest Power Pool



Source: Hitachi Energy, Velocity Suite

SPP expanded its footprint in 2015, incorporating the Western Area Power Administration – Upper Great Plains region, the Basin Electric Power Cooperative, and the Heartland Consumers Power District. The expansion nearly doubled SPP's service territory by square miles, adding more the 5 GW of peak demand and over 7 GW of generating capacity.[167]

SPP also operates a real-time energy imbalance market in the Western Interconnect, which is described further below.

Peak Demand

SPP's all-time peak demand of 53 GW occurred in summer 2022.[168]

Imports and Exports

SPP has interties with MISO, TVA, and other systems. Additionally, SPP has two DC interties with ERCOT and seven DC interties to the Western Interconnection through New Mexico, Colorado, Nebraska, South Dakota and Montana. At times, SPP is both a net importer and net exporter of electricity at times.

Market Participants

SPP's market participants include investor-owned utilities, generation and transmission cooperatives, independent power producers, municipal utilities, state authorities, independent transmission companies, power marketers, financial participants, and a federal power marketing administration.

Membership and Governance

SPP is governed by a board of directors representing and elected by its members. Supporting the board is the members committee, which provides non-binding input. The members' committee is composed of representatives from each sector of SPP's membership. The SPP Regional State Committee represents retail regulatory commissions from state agencies and provides input on matters of regional importance related to the development and operation of bulk electric transmission.

Transmission Owners

SPP's largest transmission owners include:

- American Electric Power
- Oklahoma Gas and Electric
- Westar Energy
- Southwestern Public Service (Xcel Energy)
- Great Plains Energy
- Kansas City Power & Light
- Omaha Public Power District
- Nebraska Public Power District
- Tri-State Generation and Transmission
- Empire District Electric
- Western Area Power Administration – Upper Great Plains
- Western Farmers Electric Cooperative

167 Southwest Power Pool, *Western, Basin, Heartland join Southwest Power Pool,* at 1 (October 2015), https://www.spp.org/about-us/newsroom/western-basin-heartland-join-southwest-power-pool/.

168 Southwest Power Pool, *Fast Facts*, https://www.spp.org/about-us/fast-facts/.

Chronic Constraints

SPP has certain pathways that are more likely to become congested, based on the physical characteristics of the transmission grid and associated transfer capability, the geographic distribution of load, and the geographic differences in fuel costs. The eastern side of the SPP footprint has a higher concentration of load and congestion can occur when wind-powered generation from the west tries to travel across limited connections to the east. The most significant congestion has typically occurred in the Oklahoma and Texas Panhandle region.[169]

Transmission Planning

SPP conducts its transmission planning according to its Integrated Transmission Planning process,which is a three-year planning process that includes 20-year, 10-year, and near-term assessments designed to identify transmission solutions that address both near-term and long-term transmission needs. The Integrated Transmission Planning process focuses on identifying cost-effective regional transmission solutions, which are identified in an annual SPP Transmission Expansion Plan report.

Supply Resources

The total capacity in SPP is approximately 94 GW and is predominately composed of natural gas and coal-fired generators, as shown in the bar chart below. Wind is an important and growing resource in the region.

Demand Response

SPP allows demand response resources to register in its market.[170] As of December 31, 2021, 102 demand resources participated in SPP's markets, representing 176 MW of nameplate capacity. While the demand response resources can participate in SPP's markets, they are rarely dispatched.

SPP allows Market Participants to register two types of demand response resources: Block Demand Response (BDR) resources and Dispatchable Demand Response (DDR) resources. BDR resources can participate in SPP's markets by providing energy and reserves in 60-minute blocks. DDR resources can participate in SPP's markets by providing energy, regulation, and reserves in 5-minute blocks.

MARKET FEATURES

Energy Markets

SPP operates day-ahead and real-time markets, generally consistent with the discussion in the RTO/ISO Features section of this report. SPP's real-time market operates in 5-minute intervals.

Figure 2-25: SPP Capacity Resources



Source: EIA Form 860-M[171]

169 See Southwest Power Pool Market Monitoring Unit, *State of the Market 2022* (May 2022), at 202, https://www.spp.org/documents/67104/2021%20annual%20state%20of%20the%20market%20report.pdf.

170 SPP Market Monitor, State of the Market 2021 (May 10, 2021), at 49, https://www.spp.org/documents/67104/2021%20annual%20state%20of%20the%20market%20report.pdf.

171 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M)* (released February 2022), https://www.eia.gov/electricity/data/eia860m/.

Ancillary and Other Services

Ancillary services, described in the Electricity Supply and Delivery section, are services that support the grid and reliability. SPP procures ancillary services via the co-optimized energy and ancillary services market. Separately, SPP has a ramping product to procure capacity that can quickly increase output to offset both anticipated and unforeseen future changes in generation or load within the hour, known as the Ramp Capability Product. SPP launched this ramp product in March 2022.

Market Power Mitigation

SPP applies a set of behavioral and market outcomes tests to determine if the local market is competitive and if generator offers should be adjusted to approximate short-run marginal costs. SPP's mitigation test includes a local market power test, a conduct test, and a market impact test. Where mitigation measures are triggered by the tests, SPP generates a mitigated resource offer that the RTO then uses for dispatch, commitment, and settlement purposes.

Capacity Markets

SPP does not offer a capacity market. However, it requires each Load Responsible Entity (LRE) to have sufficient energy supply (capacity) to cover its energy obligations. SPP develops and implements policies and processes necessary to ensure resource adequacy and determines the amount of capacity each LRE must have available to meet its energy obligations. [172]

Special Provisions for Essential Resource Retirements

A generator owner who wishes to retire a unit must request that SPP study the retirement of the resource no less than one year from the expected retirement date. SPP will then conduct studies to examine the potential effects of the resource retirement including the need for transmission network upgrades, if any.

Otherwise, SPP prepares annual reliability studies as part of its system planning responsibilities. In the event that the studies reveal a potential constraint on SPP's ability to deliver power to a local area on the transmission system, SPP works with regional stakeholders to find alternate transmission, operating procedure, or generation solutions for the constraint and thus maintain grid reliability. The SPP parties then determine an appropriate sharing of the costs, and, if unable to reach agreement, SPP will submit a proposed cost-sharing arrangement to FERC for approval.

Financial Transmission Rights

SPP refers to FTRs as Transmission Congestion Rights (TCR). A TCR is an instrument that entitles the holder to receive compensation, or requires the holder to pay a charge, for costs that arise from transmission congestion over a selected path, or source-and-sink pair of locations on the grid. A TCR provides the holder with revenue, or charges, equal to the difference in congestion prices in the day-ahead market across the selected TCR transmission path. SPP TCRs include monthly and annual products, as well as a long-term instrument called Long-Term Congestion Rights.

A related product, ARRs, provide their holders with a share of the revenue generated in the TCR auctions. In general, ARRs are allocated based on firm transmission rights. As with TCRs, ARRs provide transmission owners and eligible transmission service customers an offset or hedge against transmission congestion costs in the day-ahead market.

Virtual Transactions

SPP's market includes a virtual transaction feature that allows a participant to buy or sell power in the day-ahead market without requiring physical generation or load. In SPP, virtual bids are sometimes used in the day-ahead market as a placeholder or hedge for wind generation expected in the real-time market.

Credit Requirements

SPP's tariff includes credit requirements that a market participant needs to meet in order to participate in the

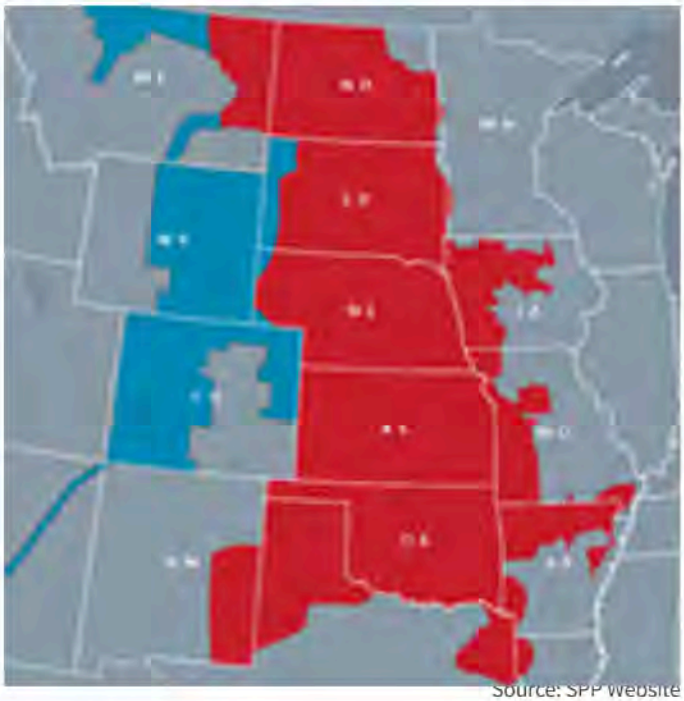
172 *Southwest Power Pool Market Monitoring Unit, State of the Market 2022 (May 2022), at 202,* https://www.spp.org/documents/67104/2021%20annual%20state%20of%20the%20market%20report.pdf

market. The credit requirements assist in mitigating the effects of defaults that would otherwise be borne among all market participants. The RTO assesses and calculates the required credit amounts for the segments of the market in which an entity requests to participate. The market participant may request an unsecured credit allowance subject to certain restrictions. SPP must review the entity's request relative to various creditworthiness-related specifications such as tangible net worth and various financial measures.

Western Energy Imbalance Service (WEIS)

SPP launched its WEIS market in February 2021. The WEIS market balances generation and load regionally in real time for participants in the Western Interconnection. SPP's WEIS market centrally dispatches generation from participating resources every five minutes using the lowest-cost resource available to meet demand. As of August 2022, ten entities participate or plan to participate in the WEIS Market with three more anticipated to join in April 2023: Basic Electric Power Cooperative, BlackHills Energy (April 2023), Colorado Springs Utilities, Deseret Power Electric Cooperative, Guzman Energy, Municipal Energy Agency of Nebraska, Platte River Power Authority (April 2023), Tri-State Generation and Transmission Association, WAPA (Upper Great Plains West, Rocky Mountain, and Colorado River Storage Projects regions), and Xcel Energy (April 2023). The following map shows SPP's footprint in red and the WEIS in blue.

Figure 2-26: Western Energy Imbalance Service



Source: SPP Website

California Independent System Operator (CAISO)

MARKET PROFILE

CAISO operates an ISO serving most of California and part of Nevada. CAISO is a California nonprofit public benefit corporation started in 1998 when the state restructured its electric power industry. CAISO manages wholesale electricity markets, centrally dispatching electric generators. In managing the grid, CAISO provides open access to the transmission system and performs long-term transmission planning. It manages energy and ancillary markets in day-ahead and real-time markets and is responsible for regional reliability. CAISO also operates a real-time energy imbalance market, the Western Energy Imbalance Market (WEIM), which is discussed further below. CAISO operates its grid out of its main control center in Folsom, CA.

Peak Demand

CAISO's all-time peak demand was 52 GW in summer 2022.[173]

Imports and Exports

Up to about one-third of CAISO's energy is supplied by imports, principally from the Southwest (Arizona, Nevada, and New Mexico) and the Pacific Northwest (Oregon, Washington, and British Columbia). Imports from the Pacific Northwest generally increase in the

173 California ISO, *California ISO Peak Load History 1998 through 2022*, at 1 (n.d.), http://www.caiso.com/documents/californiaisopeakloadhistory.pdf.

late spring when hydroelectric production peaks from increases in winter snowmelt and runoff.

Market Participants

CAISO's market participants include load-serving investor-owned utilities, load-serving municipal utilities, generators, power marketers, utility customers, and financial entities.

Membership and Governance

The CAISO has a board of governors that consists of five members appointed by the governor and confirmed by the California Senate. The board provides corporate direction, reviews and approves management's annual strategic plans, and approves CAISO's operating and capital budgets.

CAISO uses an informal stakeholder process to propose solutions to problems that may ultimately require a filing at FERC. Unlike other RTOs, which have a formal committee structure, CAISO's stakeholder process generally consists of rounds of dialogue with stakeholders on major policy issues.

Transmission Owners

CAISO's largest transmission owners include:

- Pacific Gas and Electric
- Southern California Edison
- San Diego Gas and Electric
- Valley Electric Association
- Municipal utilities such as Vernon, Anaheim, and Riverside

Chronic Constraints

CAISO has several locally constrained areas, typically near population centers and where transmission lines have relatively low voltage (115 kV and below). The locally constrained areas that have local capacity requirements include the Greater Bay Area, Greater Fresno, Sierra, Humboldt, Los Angeles Basin, San Diego, and North Coast/North Bay.

Transmission Planning

CAISO conducts an annual transmission planning process with stakeholders that includes both short-term and long-term projects.

Figure 2-27: California Independent System Operator



Source: Hitachi Energy Velocity Suite

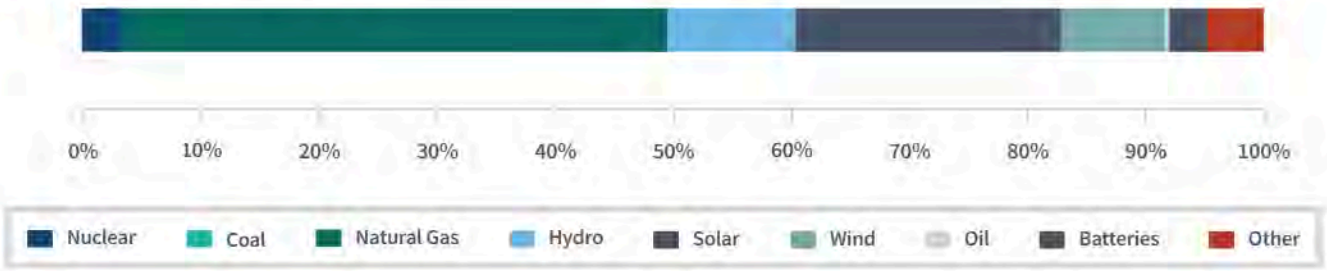
Supply Resources

The total capacity in CAISO is over 70 GW and is predominately composed of natural gas-fired and hydroelectric generators, as shown in the bar chart below. CAISO also has substantial renewable resources, including roughly half of the installed solar capacity in the U.S.

Demand Response

Demand response participation in the wholesale energy market includes programs entitled Proxy Demand Response, Reliability Demand Response Resources, and CAISO's Participating Load program. Proxy Demand Response allows for customer loads, aggregated by LSEs or third-party providers, to offer load reduction into CAISO's day-ahead, real-time, and ancillary services markets in return for compensation. Reliability Demand Response Resources allows customer loads, also aggregated by LSEs or third-party providers, to reduce load for compensation when triggered for

Figure 2-28: CAISO Capacity Mix



Source: EIA Form 860-M[175]

reliability-related events. Reliability Demand Response Resources can also offer into the day-ahead market. The Participating Load program allows the CAISO operators to directly curtail end-users' load, rather than through aggregators. This is a relatively small program that is primarily composed of the power demand from California's water pumping projects. Other demand response in California consists of programs for managing peak summer demands operated by the state's electric utilities. In general, activation of the utility demand response programs is based on criteria that are internal to the utility or when CAISO issues a Flex Alert. Flex Alerts also inform consumers of how and when to conserve electricity usage.

MARKET FEATURES

Energy Markets

CAISO operates day-ahead and real-time markets, generally consistent with the discussion in the RTO/ISO Features section of this report. CAISO operates a 15-minute market to adjust schedules from those determined in the day-ahead market, then a 5-minute market to balance supply and load in real-time. Real-time bids can be submitted up to 75 minutes before the start of the operating hour.

CAISO also procures capacity in the real-time market to provide upward and downward ramping of generation in order to accommodate changes in net load with the Flexible Ramping Product.[175] This service provides compensation to the generators selected to provide the desired flexible ramping capability.[176]

Ancillary and Other Services

Ancillary services, described in the Electricity Supply and Delivery section, are services that support the grid and reliability. CAISO procures ancillary services via its co-optimization of energy and ancillary services in its energy markets

In addition to ancillary services, CAISO has implemented a ramping product to procure capacity that can quickly increase output to offset changes in generation or load, known as the Flexible Ramping Product.

Market Power Mitigation

CAISO applies a set of behavioral and market outcome tests to determine if the local market is competitive and if generator offers should be adjusted to approximate price levels that would be seen in a competitive market – close to short-run marginal costs.

174 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M)* (released February 2022), https://www.eia.gov/electricity/data/eia860m/.

175 Net load in CAISO is total market demand minus generation output from solar and wind resources.

176 CAISO describes ramping capability as a resource's ability to move from one energy output to a higher (upward ramp) or lower (downward ramp) energy output; *California Independent System Operator Corp.*, 156 FERC ¶ 61,226, at P 2 (2016).

Figure 2-29: Western Energy Imbalance Market



Copyright © 2023 California ISO

Capacity Markets

CAISO does not operate a formal capacity market, but it does have a mandatory resource adequacy (RA) requirement. The program requires LSEs to procure 115 percent of their aggregate system load on a monthly basis, unless a different reserve margin is mandated by the LSE's local regulatory authority. The program provides deliverability criteria that each LSE must meet, as well as system and local capacity requirements and flexibility requirements.

The CAISO market rules also include must-offer provisions pertaining to resources procured as RA resources. These resources must make themselves available to the CAISO day-ahead and real-time markets for the capacity for which they were counted.

Special Provisions for Essential Resource Retirements

CAISO employs RMR contracts to assure that it has the ability to reliably serve load in local import-constrained areas. RMR contracts also help to mitigate any local market power that one or more units may have. Over time, CAISO has been able to significantly decrease its RMR designations in much of the system. Remaining generators with RMR contracts are located primarily near the San Francisco and Los Angeles areas.

Financial Transmission Rights

In California, FTRs are referred to as Congestion Revenue Rights (CRR). A CRR is an instrument that entitles the CRR holder to a payment for costs that arise with transmission congestion over a selected path, or source-and-sink pair of locations on the grid. The CRR also requires its holder to pay a charge for those hours when congestion occurs in the opposite direction of the selected source-and-sink pair. CRRs are monthly or quarterly products. CRRs can be bought at auction or allocated by CAISO. Allocated CRRs receive the congestion value for a specific path, similar to a converted FTR. CAISO also allocates open market CRR auction revenues to LSEs, based on their physical participation in the market, similar to an ARR in other markets.

Virtual Transactions

CAISO's market includes a virtual transactions feature, termed convergence bidding. CAISO's convergence bidding includes both virtual supply and virtual demand transactions.

Credit Requirements

CAISO's tariff includes credit requirements that a market participant needs to meet in order to participate in the market. The credit requirements assist in mitigating the effects of defaults that would otherwise be absorbed by all market participants. CAISO assesses and calculates the required credit dollar amounts for the segments of the market in which an entity requests to participate. The market participant may request an unsecured credit allowance subject to

certain restrictions – CAISO must review the entity's request relative to various creditworthiness-related specifications such as tangible net worth, net assets, and credit rating.

Western Energy Imbalance Market (WEIM)

On Nov. 1, 2014, CAISO began operation of an energy imbalance market (EIM) with PacifiCorp's two BAAs, PacifiCorp East and PacifiCorp West. The EIM is an extension of the CAISO's real-time market into other BAAs in the Western Interconnection. The market dispatches resources inside the participating entities' BAAs to meet intra-hour changes in their energy demand and supply. The EIM's imbalance energy helps the BAAs meet their energy demand in real-time. Overall, EIM energy represents about two to three percent of the energy used to meet load in the participating BAAs. With the balancing authorities in the Pacific Northwest, the EIM integrates low-cost hydroelectric power generation with the significant amount of solar and wind generation capacity in CAISO.

The EIM is a voluntary market where the participating balancing authorities can choose which resources to include in the market. The market participants have the flexibility to add and remove capacity from the EIM on an hourly basis. The transmission system operators for each participating BAA preserve the responsibility and flexibility to respond to events such as a sudden large imbalance between load and supply caused by a loss of a power plant or transmission line.

As of November 2022, the EIM consisted of the following LSEs and their respective BAAs: BPA, Puget Sound Energy, Portland General Electric, PacifiCorp West, PacifiCorp East, Idaho Power, NV Energy, Tucson Electric Power, Avista, NorthWestern Energy, Los Angeles Department of Water & Power, Public Service Company of New Mexico, Turlock Irrigation District, Salt River Project, Seattle City Light, Balancing Authority of Northern California, Idaho Power Company, Portland General Electric, Puget Sound, NV Energy, Arizona Public Service, and CAISO. Additionally, Powerex (the marketing arm of the Canadian utility, BC Hydro) joined the EIM, providing contributions of generation and load imbalance (the difference between generation supply and demand schedules).[177] Other balancing authorities have expressed interest in becoming EIM Entities.

The EIM provides a market mechanism for dispatching generation resources to meet imbalance energy needs along with a limited amount of power flows between the participating BAAs. The market dispatches generation based on the relative cost of the resources, resulting in cost savings for the participants. Before the EIM, a balancing authority such as PacifiCorp West or PacifiCorp East resolved imbalances between energy demand and supply in real-time by dispatching its resources and using ancillary services (mainly regulation). Under the EIM, by contrast, the market automates the dispatch of enough resource capacity within the BAAs, along with transmission flows between BAAs, to resolve energy imbalances.[178] The automated EIM sets LMPs at both 15-minute and 5-minute intervals.

Along with dispatch cost savings, the EIM also helps integrate renewable generation resources. Prior to the EIM, CAISO imported power from outside its service territory to balance load throughout most hours of the day. However, with the growth of solar and wind generation, particularly in California, there were periods when these resources were forced to curtail because there was too much energy offered into the market. Now, with the EIM, any excess power can be exported throughout the participating BAAs. In some hours, this results in power exports from CAISO to other BAAs.[179]

177 Powerex (BC Hydro) also makes transmission rights available to the EIM, providing its power to the EIM at the British Columbia-U.S. border

178 The EIM software calculates dispatch solutions for the EIM market area as a whole. Consequently, participating balancing authorities need not maintain high levels of reserves.

179 *See* Department of Market Monitoring – California ISO, *2017 Annual Report on Market Issues & Performance*, at 118 (June 2018), http://www.caiso.com/Documents/2017AnnualReportonMarketIssuesandPerformance.pdf.

As the independent system operator of the EIM, CAISO addresses local market power mitigation at 5-minute and 15-minute intervals across the EIM area, which includes the non-CAISO balancing authority areas. CAISO also procures a Flexible Ramp Product to provide upward and downward flexible capacity to meet energy ramp requirements. In these respects, CAISO's operator responsibilities have grown in the EIM as enhancements to the market design have been implemented.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-9

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

Exhibit 47

2024 Coal Ash Inspection Report

REPORT

J.H. Campbell Generating Facility
2024 Facility Inspection Report
West Olive, Michigan

Pursuant to 40 CFR 257.84

Submitted to:

Consumers Energy Company

1945 W. Parnall Road
Jackson, Michigan 49201

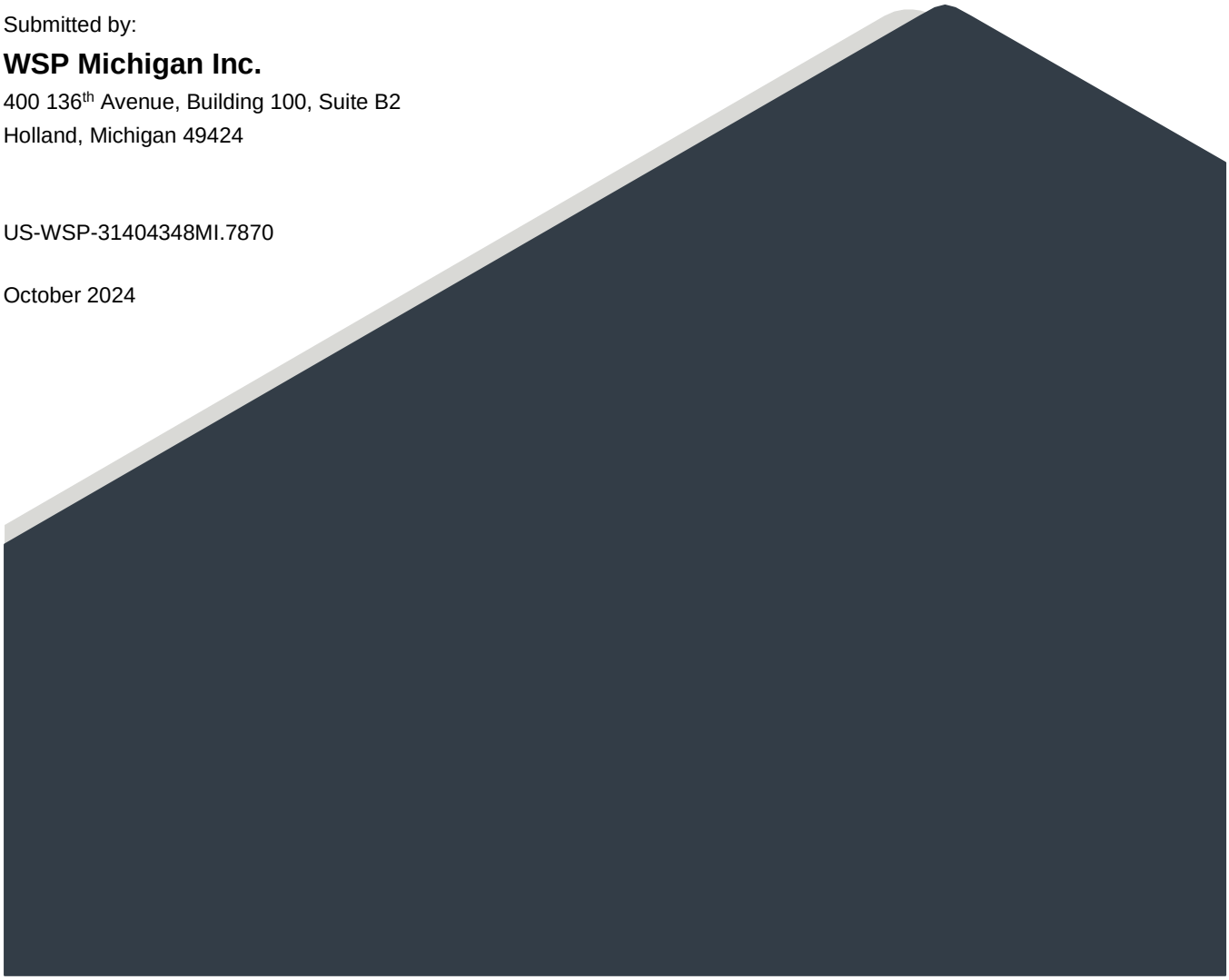
Submitted by:

WSP Michigan Inc.

400 136th Avenue, Building 100, Suite B2
Holland, Michigan 49424

US-WSP-31404348MI.7870

October 2024

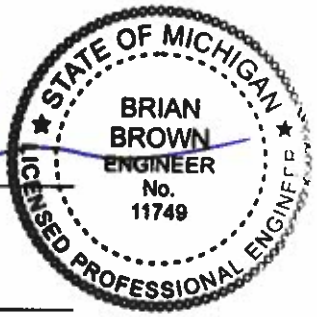


Certification

Professional Engineer Certification Statement [40 CFR 257.84]

I hereby certify that, having reviewed the attached documentation and being familiar with the provisions of Title 40 of the Code of Federal Regulations Section 257.84 (40 CFR Part 257.84), I attest that this Annual Inspection Report is accurate and has been prepared in accordance with good engineering practices, including the consideration of applicable industry standards, and with the requirements of 40 CFR Part 257.84.

WSP Michigan Inc.



Signature

October 6, 2024

Date of Report Certification

Brian A. Brown, PE

Name

6201311749

Professional Engineer Certification Number

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APPENDICES

Appendix A – Visual Inspection Checklist

1.0 INTRODUCTION

On April 17, 2015, the United States Environmental Protection Agency (EPA) issued the Coal Combustion Residual (CCR) Resource Conservation and Recovery Act (RCRA) Rule (40 CFR 257 Subpart D) ("CCR RCRA Rule"). The CCR RCRA Rule requires owners or operators of existing CCR landfills to have those units inspected on an annual basis by a qualified professional engineer (QPE) in accordance with 40 CFR 257.84(b). The annual QPE inspections are required to be completed and the results documented in inspection reports per CFR 257.84(b)(2) for landfills.

WSP Michigan Inc. (WSP) was retained by Consumers Energy Company (CEC) to perform the QPE annual inspection of the Dry Ash Landfill at the J.H. Campbell Generating Facility (JH Campbell) to document, to the extent reasonable based on information provided by CEC and the limits of the visual inspection; that the design, construction, operation, and maintenance for the CCR unit is consistent with recognized and generally accepted good engineering standards. WSP reviewed available information regarding the status and condition of the CCR unit and performed an onsite visual inspection to identify signs of distress or malfunction of the CCR unit and visible leachate collection system features.

2.0 BACKGROUND AND DOCUMENT REVIEW SUMMARY

The Dry Ash Landfill serves as the facility's primary disposal area for dry ash and currently consists of six dual lined landfill cells and two leachate storage ponds. Total permitted capacity of the landfill, per the most current Construction Permit Application (CPA) Number 4173 dated November 30, 2021, is 10,032,000 cubic yards (CY) with approximately 6,177,295 CY consumed at the time of the inspection, per Consumers reporting. It should be noted that the total permitted volume capacity will be achieved once the remaining permitted cells have been constructed and filled.

At the time of the 2024 inspection; Cells 1, 2, 3, 4, 5, and 6 had been constructed with active filling occurring in uncapped portions of Cell 4, Cell 5, and Cell 6. Phase 6 of closure construction was completed in 2019 on portions of Cells 3 and 4. A final cover system was in place on Cell 3, the eastern portion of Cell 4, the north and east slopes of Cell 2, and the north and west slope of Cell 1.

The applicable available information reviewed for this assessment is summarized in Table 1 below.

Table 1: Summary of Background Document Review

Document	Date	Author
Weekly inspections performed by CEC	July 2023 – July 2024	Dry Ash Landfill Qualified Personnel
J.H. Campbell Dry Ash Landfill 2023 Annual RCRA CCR Landfill Inspection Report	October 2023	WSP Michigan Inc.
J.H. Campbell Dry Ash Landfill 2022 Annual RCRA CCR Landfill Inspection Report	October 2022	Golder Associates Inc.
J.H. Campbell Dry Ash Landfill Solid Waste Disposal Area Construction Permit	November 2021	Golder Associates Inc.
J.H. Campbell Dry Ash Landfill 2021 Annual RCRA CCR Landfill Inspection Report	October 2021	Golder Associates Inc.
J.H. Campbell Dry Ash Landfill 2020 Annual RCRA CCR Landfill Inspection Report	October 2020	Golder Associates Inc.

Document	Date	Author
J.H. Campbell Dry Ash Landfill 2019 Annual RCRA CCR Landfill Inspection Report	October 2019	Golder Associates Inc.
J.H. Campbell Dry Ash Landfill 2018 Annual RCRA CCR Landfill Inspection Report	October 2018	Golder Associates Inc.
J.H. Campbell Dry Ash Landfill Construction Permit Upgrade Request Cells 5 through 9	March 2018	Golder Associates Inc.
J.H. Campbell Dry Ash Landfill 2017 Annual RCRA CCR Landfill Inspection Report	October 2017	Golder Associates Inc.
J.H. Campbell Dry Ash Landfill 2016 Annual RCRA CCR Landfill Inspection Report	October 2016	Golder Associates Inc.
J.H. Campbell Dry Ash Landfill 2015 Initial Annual RCRA CCR Landfill Inspection Report	January 2016	Golder Associates Inc.
Surveillance Monitoring Programs (SMPs)	December 2010, Revised 2015	CEC
J.H. Campbell Ash Storage Facility Expansion	November, 1993	STS Consultants Ltd.

3.0 2024 VISUAL INSPECTION

WSP performed an onsite inspection of the Dry Ash Landfill on August 6, 2024 and August 7, 2024. WSP inspectors Brian Brown, PE and Scott Fulmer, were accompanied by two CEC representatives, as follows:

- Mr. George McKenzie, PE - CEC System Engineering Department
- Mr. Joseph Firlit, PMP - CEC Manager Engineering Support

The inspection checklist form is provided in Appendix A. The checklist includes observations and recommendations resulting from the visual inspection and also includes the following information as stipulated in 40 CFR 257.84(b):

- Any changes in geometry of the structure since the previous annual inspection.
  - At the time of inspection, the southern portion of the landfill (Cell 4, Cell 5, and Cell 6) was undergoing active filling.
- Approximate volume of CCR at the time of inspection.
  - The volume of airspace consumed within the Dry Ash Landfill at the time of inspection was estimated at approximately 6,177,295 CY.
- Appearances of an actual or potential structural weakness of the CCR unit, in addition to any existing conditions that are disrupting or have the potential to disrupt the operation and safety of the CCR unit and appurtenant structures.
  - None were observed or noted.

- Any other change(s) which may have affected the stability or operation of the CCR unit since the previous inspection.
    - None were observed or noted.

The checklist categorizes observed conditions of the impoundment or appurtenant structures as either acceptable, monitor/maintain, investigate, or repair, which are defined as follows:

- Acceptable: The condition was visually documented to be acceptable, requiring no action beyond periodic inspection in accordance with the SMP and typical maintenance.
- Monitor/Maintain: The condition was visually identified to exhibit the potential for or show existing degeneration that should either be monitored or maintained as detailed in the checklist.
    - Items identified in this category are not considered a deficiency or release as classified under 40 CFR 257.84(b)(5) requiring immediate action by CEC.
- Investigate: The limitations of the visual inspection did not allow for an opinion to be made on the condition of the item observed, and WSP recommends additional investigation to categorize the item.
- Repair: WSP recommends that items identified with a repair designation exhibited conditions that should initiate measures be taken to rectify the area of concern.
    - It should be noted that no items identified for repair were considered a deficiency or release as classified under 40 CFR 257.84(b)(5) requiring immediate action by CEC.

Based on a review of previous inspection reports listed in Table 1 compared to conditions noted during the inspection, the following changes were observed:

- Localized areas of sparse vegetation, and some undesirable woody vegetation observed in localized areas of the Dry Ash Landfill final cover;
- Small animal burrows, animal cover damage, and minor erosion noted along north, east, and south sides of the Dry Ash landfill along storm water berms and toe;
- Minor erosion in localized areas on the Dry Ash Landfill and active measures to address historical erosion were observed; and
- Area of leachate collection sand erosion causing exposure of geocomposite observed on the Dry Ash Landfill Cell 5/6 intercell berm.

4.0 LIMITATIONS OF ASSESSMENT

WSP has conducted the site inspection and prepared this report for the Dry Ash Landfill at J.H. Campbell. The factual data, assessment, interpretations, and recommendations provided herein are based on the results of field observations from site inspections performed by WSP and review of previous site inspection reports provided to WSP by CEC and pertain to the specific project as described in this report and are not applicable to any other project or site location.

WSP has prepared this report in a manner consistent with that level of care and skill ordinarily exercised by members of the engineering and science professions currently practicing under similar conditions and has

characterized the site conditions within the limitations of the scope of services as defined by CEC and subject to the time limits and physical constraints applicable to this report. No other warranty, expressed or implied, is made. Any change of site conditions, purpose, development plans, or operation may alter the validity of this report. WSP cannot be responsible for use of this report, or portions thereof, unless WSP is requested to review and, if necessary, revise the report.

5.0 CLOSING

This report has been prepared in general accordance with normally accepted civil engineering practices to fulfill the Resource Conservation and Recovery Act (RCRA) reporting requirements in accordance with 40 CFR 257.84(b)(2). WSP has reviewed the available information on the J.H. Campbell Dry Ash Landfill and performed an onsite visual inspection. WSP's assessment is limited to the information provided by CEC and to the aspects that could be inspected visually in a safe manner. WSP cannot attest to the condition of subsurface or submerged structures.

WSP Michigan Inc.



Brian Brown, PE
Consultant, Geotechnical Engineer



Blaine Litteral, PE
Vice President

APPENDIX A

Visual Inspection Checklist

CCR LANDFILL VISUAL INSPECTION CHECKLIST

Facility Name: J.H. Campbell Dry Ash Landfill

Owner: Consumers Energy Company (CEC)

Purpose of Facility: Dry Ash Disposal

County, State: Ottawa County, Michigan

Inspected By: Brian Brown and Scott Fulmer **Inspection Date:** August 6th & 7th, 2023

Weather: 72-degrees F, Cloudy.

ITEM	Acceptable	Monitor/Maintain	Investigate	Repair	REMARKS
1. General Conditions					
a. Current volume of CCR					Total Airspace Consumed: 6,177,295 CY Volume of leachate drainage layer: 140,355 CY Volume of CCR: 6,036,940 CY
b. Alterations	X				
c. Grass cover	X				
d. Settlement / misalignment / cracks	X				None observed.
e. Leachate Collection	X				.
2. Landfill Slope					
a. Erosion – liner exposed?		X			Exposed geocomposite on Cell 5/6 intercell berm, see note 3.
b. Rodent burrows		X			Burrows observed on final cover benches, adjacent to leachate vaults, and near toe of slope, see note 3.
c. Vegetation	X				Some localized areas of sparse vegetation, see note 3.
d. Cracks/settlement	X				None observed.
e. Riprap/other erosion protection	X				
f. Slide, Slough, Scarp	X				None observed.

ITEM	Acceptable	Monitor/Maintain	Investigate	Repair	REMARKS
g. Benches	X				
h. Final Cover		X			Localized areas of minor erosion on final cover slopes, see note 3.
i. Downchutes	X				
3. Crest					
a. Soil condition	X				
b. Comparable to design width or previous inspection	X				
c. Vegetation	X				
d. Rodent burrows	X				
e. Exposed to heavy traffic	X				
f. Damage from vehicles / machinery	X				None observed.
4. Toe					
a. Vegetation	X				
b. Rodent burrows		X			Small animal burrows observed near toe of slope, see note 3.
c. Settlement	X				None observed.
d. Drainage conditions	X				
e. Seepage	X				None observed.

Notes:

1) Leachate collection system inspection was limited by visual observation of surficial components of the system, i.e. condition of riser pipes.
2) Maintain erosion controls per the SMP. This is not a deficiency or release as classified under 40 CFR 257.84(b)(5).
3) Features observed and documented in this checklist were not considered a deficiency or release as classified under 40 CFR 257.84(b)(5) and required no immediate action beyond periodic inspection in accordance with the SMP and typical maintenance.



wsp.com

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-9

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

Exhibit 48

2021 CWA Permit

PERMIT NO. MI0001422

STATE OF MICHIGAN
DEPARTMENT OF ENVIRONMENT, GREAT LAKES, AND ENERGY

AUTHORIZATION TO DISCHARGE UNDER THE NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM

In compliance with the provisions of the Federal Water Pollution Control Act, 33 U.S.C., Section 1251 *et seq*., as amended; Part 31, Water Resources Protection, of the Natural Resources and Environmental Protection Act, 1994 PA 451, as amended (NREPA); Part 41, Sewerage Systems, of the NREPA; and Michigan Executive Order 2019-06,

Consumers Energy Company
One Energy Plaza
Jackson, MI 49201

is authorized to discharge from the **Consumers Energy Company, J. H. Campbell Power Plant** located at

17000 Croswell St.
West Olive, MI 49460

designated as **CECO-J H Campbell Power Plt**

to the receiving waters named Lake Michigan and the Pigeon River in accordance with effluent limitations, monitoring requirements, and other conditions set forth in this permit.

This permit is based on a complete application submitted on March 22, 2016, as amended through September 1, 2016; and a complete modification request submitted on January 11, 2021.

This permit originally took effect on June 1, 2018. This modified permit takes effect on October 1, 2021. The provisions of this permit are severable. After notice and opportunity for a hearing, this permit may be modified, suspended, or revoked in whole or in part during its term in accordance with applicable laws and rules. On its original effective date, the permit superseded National Pollutant Discharge Elimination System (NPDES) Permit No. MI0001422 (expiring October 1, 2016).

This permit and the authorization to discharge shall expire at midnight on **October 1, 2022**. In order to receive authorization to discharge beyond the date of expiration, the permittee shall submit an application that contains such information, forms, and fees as are required by the Michigan Department of Environment, Great Lakes, and Energy (Department) by **April 4, 2022**.

Issued: May 29, 2018. Modified (major) September 30, 2021.

Original signed by Christine Alexander
Christine Alexander, Manager
Permits Section
Water Resources Division

PERMIT FEE REQUIREMENTS

In accordance with Section 324.3120 of the NREPA, the permittee shall make payment of an annual permit fee to the Department for each October 1 the permit is in effect regardless of occurrence of discharge. The permittee shall submit the fee in response to the Department's annual notice. Payment may be made electronically via the Department's MiWaters system. The MiWaters website is located at https://miwaters.deq.state.mi.us. Payment shall be submitted or postmarked by January 15 for notices mailed by December 1. Payment shall be submitted or postmarked no later than 45 days after receiving the notice for notices mailed after December 1.

Annual Permit Fee Classification: Industrial-Commercial Major

In accordance with Section 324.3118 of the NREPA, the permittee shall make payment of an annual storm water fee to the Department for each January 1 the permit is in effect regardless of occurrence of discharge. The permittee shall submit the fee in response to the Department's annual notice. Payment may be made electronically via the Department's MiWaters system. The MiWaters website is located at https://miwaters.deq.state.mi.us. Payment shall be submitted or postmarked by March 15 for notices mailed by February 1. Payment shall be submitted or postmarked no later than 45 days after receiving the notice for notices mailed after February 1.

CONTACT INFORMATION

Unless specified otherwise, all contact with the Department required by this permit shall be made to the Grand Rapids District Office of the Water Resources Division. The Grand Rapids District Office is located at State Office Building, Fifth Floor, 350 Ottawa Ave NW, Unit 10, Grand Rapids, Michigan, 49503-2341, Telephone: 616-356-0500, Fax: 616-356-0202.

CONTESTED CASE INFORMATION

Any person who is aggrieved by this permit may file a sworn petition with the Michigan Administrative Hearing System within the Michigan Department of Licensing and Regulatory Affairs, c/o the Michigan Department of Environment, Great Lakes, and Energy, setting forth the conditions of the permit which are being challenged and specifying the grounds for the challenge. The Department of Licensing and Regulatory Affairs may reject any petition filed more than 60 days after issuance as being untimely.

PART I

Section A. Limitations and Monitoring Requirements

1. Effluent Limitations, Monitoring Point 001A

During the period beginning on the effective date of this permit and lasting until the expiration date of this permit, the permittee is authorized to discharge a maximum of 984.841 MGD of noncontact cooling water; intake screen backwash; low volume wastewater, which includes but is not limited to: boiler blowdown, boiler drainage, recirculating house service water, laboratory and sampling streams, and water from floor drains; bottom ash transport water; chemical metal cleaning wastewater; coal pile runoff; storm water; leachate retention pond water; reverse osmosis backwash and reject water; and groundwater seepage from ash ponds and the recirculation pond from Monitoring Point 001A through Outfall 001. Outfall 001 discharges to Lake Michigan at Latitude 42.91164, Longitude -86.21269. Such discharge shall be limited and monitored by the permittee as specified below.

	Maximum Limits for Quantity or Loading			Maximum Limits for Quality or Concentration				
Parameter	**Monthly**	**Daily**	**Units**	**Monthly**	**Daily**	**Units**	**Monitoring Frequency**	**Sample Type**
Flow	(report)	(report)	MGD	---	---	---	Daily	Report Total Daily Flow
Total Residual Oxidant (TRO) – See Part I.A.1.g.								
During Chlorination – No Bromine Use								
Total Residual Chlorine (TRC) Discharge Time			---	---	(report)	min/day	Daily	Report Total Discharge Time
Continuous (greater than 160 min/day)	---	---	---	---	38	ug/l	Daily	Grab
				Daily Average	**Instantaneous Maximum**			
Intermittent (less than/equal to 160 min/day)				200	300	ug/l	Daily	Grab
During Bromination – Alone or With Chlorine								
Intermittent (less than/equal to 120 min/day)				(report)	50	ug/l	Daily	Grab
					Maximum Daily			
TRO Discharge Time		---	---	---	120	min/day	Daily	Report Total Discharge Time
Total Phosphorus (as P)	---	(report)	lbs/day	---	(report)	mg/l	Quarterly	Grab
Total Copper, see Part I.A.1.i.	---	---	---	---	(report)	mg/l	Daily	Grab
Total Iron, see Part I.A.1.i.	---	---	---	---	(report)	mg/l	Daily	Grab
EVAC (as amine)	---	---	---	---	78	ug/l	Every 2 Hrs During Discharge	Grab
Temperature								
Intake (Unit 3 intake)	---	---	---	(report)	(report)	°F	Daily	Continuous
Discharge	---	---	---	(report)	(report)	°F	Daily	Continuous
Outfall Observation	(report)	---	---	---	---	---	5X Weekly	Visual

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Section A. Limitations and Monitoring Requirements

Parameter	Maximum Limits for Quantity or Loading			Maximum Limits for Quality or Concentration			Monitoring	Sample
	Monthly	Daily	Units	Monthly	Daily	Units	Frequency	Type
				Minimum Daily				
pH	---	---	---	6.5	9.0	S.U.	2X Monthly	Grab

a. Narrative Standard
The receiving water shall contain no turbidity, color, oil films, floating solids, foams, settleable solids, suspended solids, or deposits as a result of this discharge in unnatural quantities which are or may become injurious to any designated use.

b. Monitoring Location
Samples, measurements, and observations taken in compliance with the monitoring requirements above shall be taken prior to discharge to Lake Michigan. Intake temperature monitoring shall be taken at the Unit 3 intake.

c. Outfall Observation
Outfall observation shall be reported as "yes" or "no." The permittee shall report yes if this requirement was completed and no if this requirement was not completed. Any unusual characteristics of the discharge (i.e., unnatural turbidity, color, oil film, floating solids, foams, settleable solids, suspended solids, or deposits) shall be reported within 24 hours to the Department followed with a written report within 5 days detailing the findings of the investigation and the steps taken to correct the condition.

d. Quarterly Monitoring
Quarterly samples shall be taken during the months of January, April, July, and October. If the facility does not discharge during these months, the permittee shall sample the next discharge occurring during the period in question. If the facility does not discharge during the period in question, a sample is not required for that period. For any month in which a sample is not taken, the permittee shall enter "*G" on the Discharge Monitoring Report (DMR).

e. Water Treatment Additives
This permit does not authorize the discharge of water treatment additives without approval. Approval of water treatment additives is authorized under separate correspondence. Water treatment additives include any material that is added to water used at the facility or to a wastewater generated by the facility to condition or treat the water. In the event a permittee proposes to discharge water treatment additives, including an increased discharge concentration of a previously approved water treatment additive, the permittee shall submit a request for approval in accordance with Part I.A.6. of this permit.

f. Analytical Methods and Quantification Levels for Total Phosphorus and Total Copper
The sampling procedures, preservation and handling, and analytical protocol for compliance monitoring for Total Phosphorus and Total Copper shall be in accordance with Part II.B.2. of this permit. The quantification level for Total Phosphorus and Total Copper, shall be 10 ug/l and 1.0 ug/l, respectively, unless a higher level is appropriate because of sample matrix interference. Justification for higher quantification levels shall be submitted to the Department within 30 days of such determination. Upon approval from the Department, the permittee may use alternate analytical methods (for parameters with methods specified in Title 40 of the Code of Federal Regulations (CFR), Part 136, the alternate methods are restricted to those listed in 40 CFR, Part 136).

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Section A. Limitations and Monitoring Requirements

g. Total Residual Oxidant (Chlorine and Bromine) Requirements

Total Residual Oxidant (TRO) shall be analyzed in accordance with Part II.B.2. of this permit. TRO monitoring is only required during periods of chlorine or bromine use and subsequent discharge. The limitations specified in Part I.A.1. for the intermittent discharge of chlorine alone apply only when the discharge of chlorine alone is less than or equal to 160 minutes per day, otherwise the limitations for continuous discharge of chlorine alone apply. Authorization to discharge bromine alone or with chlorine is limited to 120 minutes per day at the limitations specified in Part I.A.1., with the additional requirement that any discharge of chlorine is further restricted to a concurrent discharge with bromine (no additional discharge of chlorine is authorized for that day).

During the intermittent discharge of chlorine without bromine ("During Chlorination – No Bromine Use"), the daily average concentration reported for TRC shall be the average of the individual analytical results of a minimum of three (3) grab samples collected at equal intervals during a chlorine discharge event, with the additional limitation that no single sample may exceed 300 ug/l.

During the intermittent discharge of bromine alone or with chlorine ("During Bromination – Alone or With Chlorine"), the daily average concentration reported for TRO shall be the average of the individual analytical results of a minimum of three (3) grab samples collected at equal intervals during a bromine, or bromine plus chlorine, discharge event, with the limitation that no single sample may exceed 50 ug/l of TRO.

The permittee shall enter "*G" on the Discharge Monitoring Report for the TRO discharge modes not being used.

The permittee may use dehalogenation techniques to achieve the applicable TRO limitations, using sodium thiosulfate, sodium sulfite, sodium bisulfite, or other dehalogenating reagents approved by the Department. The quantity of the reagent(s) used shall be limited to 0.6 times the stoichiometric amount of TRO for sodium thiosulfate, 1.5 times the stoichiometric amount of TRO for sodium bisulfite, and 1.8 times the stoichiometric amount of TRO for sodium sulfite. The TRO samples taken to determine the amount of each chemical to add shall be taken upstream of dehalogenation.

h. Zebra Mussel Control Requirements

The discharge of EVAC (as amine) is restricted to no more than six (6) times per year, for no more than 12 hours per discharge event. The permittee shall notify the Department at least one (1) week prior to each discharge.

The sampling procedure, preservation and handling, and analytical protocol for compliance monitoring for EVAC (as amine) shall be in accordance with the Acid Orange Method. The quantification level shall not exceed 50 ug/l for EVAC (as amine), unless higher levels are appropriate because of sample matrix interference. Justification for higher quantification levels shall be submitted to the Department within 30 days of such determination. Other methods may be used upon approval from the Department. The highest value measured during the discharge event shall be reported. If the concentration in all samples is less than the quantification level, report “<” the quantification level used by the analyzing laboratory on the DMR.

i. Total Copper and Total Iron Monitoring

The monitoring requirements for total copper and total iron apply only when a discharge from the chemical treatment facility occurs through Monitoring Point 001A.

j. Temperature Monitoring

When the continuous temperature monitoring system is inoperative, the effluent daily maximum temperature may be reported on a single daily reading.

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Section A. Limitations and Monitoring Requirements

k. Acid Cleaning
The periodic use of Muriatic acid for cleaning sodium hypochlorite injection systems nozzles is approved.

l. Power Plants – Polychlorinated Biphenyls (PCB) Prohibition
The permittee shall not discharge any PCBs to the receiving waters of the state of Michigan as a result of plant operations.

2. Effluent Limitations, Monitoring Point 001B (Ash Pond System Discharge)

During the period beginning on the effective date of this permit and lasting until the expiration date of this permit, the permittee is authorized to discharge a maximum of 7.77 MGD of bottom ash transport water; chemical metal cleaning wastewater; coal pile runoff; low volume wastewater, which includes but is not limited to: boiler blowdown, boiler drainage, recirculating house service water, laboratory and sampling streams, reverse osmosis backwash and reject, and water from floor drains; storm water; leachate retention pond water; and groundwater seepage from ash ponds and recirculation pond from Monitoring Point 001B through Monitoring Point 001A and Outfall 001. Outfall 001 discharges to Lake Michigan at Latitude 42.91164, Longitude -86.21269. Such discharge shall be limited and monitored by the permittee as specified below.

	Maximum Limits for Quantity or Loading			Maximum Limits for Quality or Concentration			Monitoring	Sample
Parameter	**Monthly**	**Daily**	**Units**	**Monthly**	**Daily**	**Units**	**Frequency**	**Type**
Flow	---	(report)	MGD	---	---	---	Monthly	Report Total Daily Flow
Total Suspended Solids	---	---	---	30	50	mg/l	Monthly	Grab
Oil & Grease	---	---	---	15	20	mg/l	Annually	Grab
Total Copper, see Part I.A.2.a.	---	---	---	---	1.0	mg/l	Daily	Grab
Total Iron, see Part I.A.2.a.	---	---	---	---	1.0	mg/l	Daily	Grab

a. Total Copper and Total Iron Limits
The limits and monitoring requirements for total copper and total iron apply only to the discharge from the chemical treatment facility when operating. The chemical treatment facility effluent shall not be mixed with any other waste stream prior to sampling for compliance monitoring. All samples shall be taken prior to discharge to the recirculation pond.

b. Monitoring Location
Samples, measurements, and observations taken in compliance with the monitoring requirements above shall be taken prior to the Unit 2 condenser discharge channel.

c. Annual Monitoring
Annual samples shall be taken during the month of April. If the facility does not discharge during this month, the permittee shall sample the next discharge occurring during the period in question. If the facility does not discharge during the period in question, a sample is not required for that period. For any month in which a sample is not taken, the permittee shall enter "*G" on the Discharge Monitoring Report (DMR).

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d. Analytical Methods and Quantification Levels for Total Copper
The sampling procedures, preservation and handling, and analytical protocol for compliance monitoring for Total Copper shall be in accordance with Part II.B.2. of this permit. The quantification level for Total Copper shall be 1.0 ug/l unless a higher level is appropriate because of sample matrix interference. Justification for higher quantification levels shall be submitted to the Department within 30 days of such determination. Upon approval from the Department, the permittee may use alternate analytical methods (for parameters with methods specified in Title 40 of the Code of Federal Regulations (CFR), Part 136, the alternate methods are restricted to those listed in 40 CFR, Part 136).

3. Effluent Limitations, Monitoring Point 001C (Plant Oil/Water Separator Discharge)

During the period beginning on the effective date of this permit and lasting until the expiration date of this permit, the permittee is authorized to discharge a maximum of 9.65 MGD of noncontact cooling water; low volume wastewater, which includes but is not limited to: boiler blowdown, recirculating house service water, laboratory and sampling streams, and water from floor drains; treated coal pile runoff; and storm water from Monitoring Point 001C through Monitoring Point 001A and Outfall 001. Outfall 001 discharges to Lake Michigan at Latitude 42.91164, Longitude -86.21269. Such discharge shall be limited and monitored by the permittee as specified below.

	Maximum Limits for Quantity or Loading			Maximum Limits for Quality or Concentration			Monitoring	Sample
Parameter	**Monthly**	**Daily**	**Units**	**Monthly**	**Daily**	**Units**	**Frequency**	**Type**
Flow	---	(report)	MGD	---	---	---	Monthly	Report Total Daily Flow
Total Suspended Solids	---	---	---	25	40	mg/l	Monthly	Grab
Oil & Grease	---	---	---	---	10	mg/l	Monthly	Grab

a. Monitoring Location
Samples, measurements, and observations taken in compliance with the monitoring requirements above shall be taken prior to discharge to Units 1 & 2 intake channel.

b. Monitoring Frequency Reduction for Oil & Grease
After the submittal of 12 months of data, the permittee may request, in writing, Department approval for a reduction in monitoring frequency for Oil & Grease. This request shall contain an explanation as to why the reduced monitoring is appropriate. Upon receipt of written approval and consistent with such approval, the permittee may reduce the monitoring frequency indicated in Part I.A.3. of this permit. The monitoring frequency for Oil & Grease shall not be reduced to less than Annually. The Department may revoke the approval for reduced monitoring at any time upon notification to the permittee.

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4. Effluent Limitations, Monitoring Point 002A (Ash Pond Discharge)

During the period beginning on the effective date of this permit and lasting until the expiration date of this permit, the permittee is authorized to discharge a maximum of 10.45 MGD of bottom ash transport water; economizer ash wastewater; chemical metal cleaning wastewater; coal pile runoff; low volume wastewater which includes but is not limited to: ion exchange wastewater, boiler blowdown, boiler drainage, recirculating house service water, laboratory and sampling streams, reverse osmosis backwash and reject water, and water from floor drains; storm water; and groundwater seepage from ash ponds and the recirculation pond from Monitoring Point 002A through Outfall 002. Outfall 002 discharges to the Pigeon River at Latitude 42.90292, Longitude -86.196033. Such discharge shall be limited and monitored by the permittee as specified below.

	Maximum Limits for Quantity or Loading			Maximum Limits for Quality or Concentration			Monitoring	Sample
Parameter	**Monthly**	**Daily**	**Units**	**Monthly**	**Daily**	**Units**	**Frequency**	**Type**
Flow	(report)	(report)	MGD	---	---	---	2X Monthly	Report Total Daily Flow
Total Suspended Solids	---	---	---	30	50	mg/l	Monthly	Grab
Oil & Grease	---	---	---	15	20	mg/l	Annually	Grab
Total Copper, see Part I.A.4.f.	---	---	---	---	(report)	mg/l	Daily	Grab
Total Iron, see Part I.A.4.f.	---	---	---	---	(report)	mg/l	Daily	Grab
Total Arsenic	---	(report)	lbs/day	---	(report)	ug/l	Quarterly	Grab
Total Phosphorus (as P)	---	(report)	lbs/day	---	(report)	mg/l	Quarterly	Grab
Total Selenium	0.47	(report)	lbs/day	5.3	(report)	ug/l	Quarterly	Grab
EVAC (as amine), see Part I.A.4.h.		---	---	---	78	ug/l	See Permit Requirements	Grab
Outfall Observation	(report)	---	---	---	---	---	5X Weekly	Visual
				Minimum Daily				
pH	---	---	---	6.5	9.0	S.U.	2X Monthly	Grab

a. Narrative Standard
The receiving water shall contain no turbidity, color, oil films, floating solids, foams, settleable solids, or deposits as a result of this discharge in unnatural quantities which are or may become injurious to any designated use.

b. Monitoring Location
Samples, measurements, and observations taken in compliance with the monitoring requirements above shall be taken prior to discharge to the Pigeon River.

c. Outfall Observation
Outfall observation shall be reported as "yes" or "no." The permittee shall report yes if this requirement was completed and no if this requirement was not completed. Any unusual characteristics of the discharge (i.e., unnatural turbidity, color, oil film, floating solids, foams, settleable solids, suspended

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Section A. Limitations and Monitoring Requirements

solids, or deposits) shall be reported within 24 hours to the Department followed with a written report within 5 days detailing the findings of the investigation and the steps taken to correct the condition.

d. Quarterly and Annual Monitoring
Quarterly samples shall be taken during the months of January, April, July, and October. Annual samples shall be taken during the month of April. If the facility does not discharge during these months, the permittee shall sample the next discharge occurring during the period in question. If the facility does not discharge during the period in question, a sample is not required for that period. For any month in which a sample is not taken, the permittee shall enter "*G" on the Discharge Monitoring Report (DMR).

e. Water Treatment Additives
This permit does not authorize the discharge of water treatment additives without approval. Approval of water treatment additives is authorized under separate correspondence. Water treatment additives include any material that is added to water used at the facility or to a wastewater generated by the facility to condition or treat the water. In the event a permittee proposes to discharge water treatment additives, including an increased discharge concentration of a previously approved water treatment additive, the permittee shall submit a request for approval in accordance with Part I.A.6. of this permit.

f. Total Copper and Total Iron Monitoring
The monitoring requirements for total copper and total iron apply only when a discharge from the chemical treatment facility occurs through Monitoring Point 002A.

g. Analytical Methods and Quantification Levels for Total Arsenic, Total Copper, and Total Phosphorus
The sampling procedures, preservation and handling, and analytical protocol for compliance monitoring for Total Arsenic, Total Copper, and Total Phosphorus shall be in accordance with Part II.B.2. of this permit. The quantification level for Total Arsenic, Total Copper, and Total Phosphorus shall be 1.0 ug/l, 1.0 ug/l, and 10 ug/l, respectively, unless a higher level is appropriate because of sample matrix interference. Justification for higher quantification levels shall be submitted to the Department within 30 days of such determination. Upon approval from the Department, the permittee may use alternate analytical methods (for parameters with methods specified in Title 40 of the Code of Federal Regulations (CFR), Part 136, the alternate methods are restricted to those listed in 40 CFR, Part 136).

h. Zebra Mussel Control Requirements
The discharge of EVAC (as amine) is restricted to no more than six (6) times per year, for no more than five (5) days per discharge event. The permittee shall notify the Department at least one (1) week prior to each discharge. Upon initiation of each EVAC treatment, samples shall be collected at Monitoring Point 002A at least once every three hours for a twelve (12) hour period. Once treatment is complete following the twelve (12) hour period, sampling will occur once daily the following day for five consecutive days to show that the concentration (as an amine) measured at Monitoring Point 002A is below detection (zero).

The sampling procedure, preservation and handling, and analytical protocol for compliance monitoring for EVAC (as amine) shall be in accordance with the Acid Orange Method. The quantification level shall not exceed 50 ug/l for EVAC (as amine), unless higher levels are appropriate because of sample matrix interference. Justification for higher quantification levels shall be submitted to the Department within 30 days of such determination. Other methods may be used upon approval from the Department. The highest value measured during the discharge event shall be reported. If the concentration in all samples is less than the quantification level, report “<” the quantification level used by the analyzing laboratory on the DMR.

i. Power Plants – Polychlorinated Biphenyls (PCB) Prohibition
The permittee shall not discharge any PCBs to the receiving waters of the state of Michigan as a result of plant operations.

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5. Effluent Limitations, Monitoring Point 002C

During the period beginning on the effective date of this permit and lasting until the expiration date of this permit, the permittee is authorized to discharge a maximum of 1.092 MGD of chemical metal cleaning wastewater from Monitoring Point 002C through Monitoring Point 002A and Outfall 002. Outfall 002 discharges to the Pigeon River at Latitude 42.90292, Longitude -86.196033. Such discharge shall be limited and monitored by the permittee as specified below.

	Maximum Limits for Quantity or Loading			Maximum Limits for Quality or Concentration			Monitoring	Sample
Parameter	**Monthly**	**Daily**	**Units**	**Monthly**	**Daily**	**Units**	**Frequency**	**Type**
Flow	---	(report)	MGD	---	---	---	Monthly	Report Total Daily Flow
Total Copper, see Part I.A.5.a.	---	---	---	---	1.0	mg/l	Daily	Grab
Total Iron, see Part I.A.5.a.	---	---	---	---	1.0	mg/l	Daily	Grab

a. Total Copper and Total Iron Limits
The limits and monitoring requirements for total copper and total iron apply only to the discharge from the chemical treatment facility when operating. The chemical treatment facility effluent shall not be mixed with any other waste stream prior to sampling for compliance monitoring. All samples shall be taken prior to discharge to the recirculation pond.

b. Monitoring Location
Samples, measurements, and observations taken in compliance with the monitoring requirements above shall be taken prior to the Unit 2 condenser discharge channel.

c. Analytical Methods and Quantification Levels for Total Copper
The sampling procedures, preservation and handling, and analytical protocol for compliance monitoring for Total Copper shall be in accordance with Part II.B.2. of this permit. The quantification level for Total Copper shall be 1.0 ug/l unless a higher level is appropriate because of sample matrix interference. Justification for higher quantification levels shall be submitted to the Department within 30 days of such determination. Upon approval from the Department, the permittee may use alternate analytical methods (for parameters with methods specified in Title 40 of the Code of Federal Regulations (CFR), Part 136, the alternate methods are restricted to those listed in 40 CFR, Part 136).

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6. Request for Discharge of Water Treatment Additives

Prior to discharge of any water treatment additive, the permittee shall obtain written approval from the Department. Requests for such approval shall be submitted via the Department's MiWaters system. The MiWaters website is located at https://miwaters.deq.state.mi.us. Instructions for submitting such a request may be obtained at http://www.michigan.gov/deqnpdes (near the bottom of that page, click on one or both of the links located under the Water Treatment Additives banner). Additional monitoring and reporting may be required as a condition for the approval to discharge the additive.

A request to discharge water treatment additives shall include all of the following usage and discharge information for each water treatment additive proposed to be discharged:

a. Safety Data Sheet (formerly known as Material Safety Data Sheet);

b. the proposed water treatment additive discharge concentration with supporting calculations;

c. the discharge frequency (i.e., number of hours per day and number of days per year);

d. the outfall and monitoring point from which the product is to be discharged;

e. the type of removal treatment, if any, that the water treatment additive receives prior to discharge;

f. the product's function (i.e. microbiocide, flocculant, etc.);

g. a 48-hour LC_{50} or EC_{50} for a North American freshwater planktonic crustacean (either *Ceriodaphnia sp., Daphnia sp., or Simocephalus sp.*); and

h. the results of a toxicity test for one (1) other North American freshwater aquatic species (other than a planktonic crustacean) that meets a minimum requirement of R 323.1057(2) of the Water Quality Standards. Examples of tests that would meet this requirement include a 96-hour LC_{50} for rainbow trout, bluegill, or fathead minnow.

7. Cold Shock Prevention

Cessation of thermal inputs to the receiving water by this facility shall occur gradually so as to avoid fish mortality due to cold shock during the winter months (November through March). The basis for this requirement is to allow fish associated with the discharge-heated mixing zone for Outfall 001 to acclimate to the decreasing temperature. The Department acknowledges that the permittee meets this condition based on the equipment and practices implemented at Outfall 001 identified in the application.

8. Intake Screen Backwash, Outfall 001

During the period beginning on the effective date of this permit and lasting until the expiration date of this permit, the permittee is authorized to discharge intake screen backwash from Outfall 001 to Lake Michigan. The permittee shall collect and remove debris accumulated on intake trash bars and dispose of such material on land in an appropriate manner.

9. Periodic/Temporary Rerouting of Combined Plant Discharge

The permittee is authorized to divert the combined flow from Units 1 & 2 and Unit 3 offshore intake structure under the following conditions: (a) for deicing when the intake water temperature falls below 36° F and intakes are at risk of becoming partially or completely restricted because of icing, (b) when Unit 3 is off line during a scheduled or unscheduled outage and the deepwater discharge pumps are turned off, or (c) for thermal treatment or control of zebra mussels and asiatic clams. The permittee is not required to provide any additional monitoring of this discharge because the effluent limitations and monitoring requirements for Outfall 001, for

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which monitoring/reporting shall be continued as usual during the diversion, will determine compliance with the applicable water quality standards and any other requirements.

10. Cooling Water Intake Structures – Interim Approval

The federal rules promulgated by the United States Environmental Protection Agency (USEPA) in 40 CFR Parts 122 and 125 establishing the requirements of section 316(b) of the Clean Water Act for Existing Facilities took effect October 14, 2014. Beginning October 14, 2014, any facility covered by the rules requesting permit reissuance shall submit an application in accordance with the rules and shall be subject to the best technology available (BTA) standards for impingement mortality and entrainment as defined in the rules. In accordance with 40 CFR 125.95(a)(2), the Department approved the permittee's March 10, 2016, request for an alternate schedule for submission of the information required in 40 CFR 122.21(r). The alternate schedule for submission of the reports identified in the request for is set for April 30, 2018 (received).

The cooling water intake structure operated by the permittee has been evaluated using all available information relating to its location, design, construction, and capacity. At this time, the Department has made an **interim** determination that the cooling water intake structure represents BTA to minimize adverse environmental impact in accordance with section 316(b) of the federal Clean Water Act (33 U.S.C. section 1326). The permittee shall at all times properly operate and maintain the cooling water intake structure and associated equipment to minimize adverse environmental impact. The permittee shall give advance notice to the Department of any planned changes in the location, design, operation, or capacity of the intake structure. If the Department determines that additional technologies or control measures are necessary to reduce the impact of impingement or entrainment, the Department may revise the requirements of this condition. Nothing in this permit shall either be construed to relieve the permittee from civil or criminal penalties for previous or future fish losses, or authorize take for the purposes of a facility's compliance with the Endangered Species Act.

11. Facility Contact

The "Facility Contact" was specified in the application. The permittee may replace the facility contact at any time, and shall notify the Department in writing within 10 days after replacement (including the name, address and telephone number of the new facility contact).

a. The facility contact shall be (or a duly authorized representative of this person):
- for a corporation, a principal executive officer of at least the level of vice president; or a designated representative if the representative is responsible for the overall operation of the facility from which the discharge originates, as described in the permit application or other NPDES form,
- for a partnership, a general partner,
- for a sole proprietorship, the proprietor, or
- for a municipal, state, or other public facility, either a principal executive officer, the mayor, village president, city or village manager or other duly authorized employee.

b. A person is a duly authorized representative only if:
- the authorization is made in writing to the Department by a person described in paragraph a. of this section; and
- the authorization specifies either an individual or a position having responsibility for the overall operation of the regulated facility or activity such as the position of plant manager, operator of a well or a well field, superintendent, position of equivalent responsibility, or an individual or position having overall responsibility for environmental matters for the facility (a duly authorized representative may thus be either a named individual or any individual occupying a named position).

Nothing in this section obviates the permittee from properly submitting reports and forms as required by law.

PART I

Section A. Limitations and Monitoring Requirements

12. Discharge Monitoring Report – Quality Assurance Study Program

The permittee shall participate in the Discharge Monitoring Report – Quality Assurance (DMR-QA) Study Program. The purpose of the DMR-QA Study Program is to annually evaluate the proficiency of all in-house and/or contract laboratory(ies) that perform, on behalf of the facility authorized to discharge under this permit, the analytical testing required under this permit. In accordance with Section 308 of the Clean Water Act (33 U.S.C. § 1318); and R 323.2138 and R 323.2154 of Part 21, Wastewater Discharge Permits, promulgated under Part 31 of the NREPA, participation in the DMR-QA Study Program is required for all major facilities, and for minor facilities selected for participation by the Department.

Annually and in accordance with DMR-QA Study Program requirements and submittal due dates, the permittee shall submit to the Michigan DMR-QA Study Program state coordinator all documentation required by the DMR-QA Study. DMR-QA Study Program participation is required only for the analytes required under this permit and only when those analytes are also identified in the DMR-QA Study.

If the permitted facility's status as a major facility should change, participation in the DMR-QA Study Program may be reevaluated. Questions concerning participation in the DMR-QA Study Program should be directed to the Michigan DMR-QA Study Program state coordinator.

All forms and instructions required for participation in the DMR-QA Study Program, including submittal due dates and state coordinator contact information, can be found at http://www.epa.gov/compliance/discharge-monitoring-report-quality-assurance-study-program.

13. Schedule of Compliance for Bottom Ash Transport Water

The permittee shall manage the discharge of bottom ash transport water (BATW) to surface waters of the state in accordance with EPA's Final Steam Electric Reconsideration Rule (Final Rule), effective October 13, 2020. This schedule of compliance (SOC) is based on two separate compliance pathways established by the Final Rule for BATW: the Cessation of Coal Burning Activities subcategory, and the implementation of an ELG-compliant technology. The permittee shall attain compliance with the Final Rule by completing the following requirements.

a. On or before October 13, 2021, the permittee shall:

1) submit a Notice of Planned Participation (NOPP) in the Cessation of Coal Burning Activities subcategory in accordance with 40 CFR §423.19 – if this compliance pathway is being considered, and/or

2) submit an update on the feasibility evaluation to select an ELG-compliant technology – if this compliance pathway is being considered.

b On or before April 4, 2022, with the application for reissuance, the permittee shall submit a description of the ELG-compliant technology selected – if the ELG-compliant technology pathway is being considered.

PART I

Section A. Limitations and Monitoring Requirements

c. On or before December 31, 2022, the permittee shall:

1) submit an annual progress report in accordance with 40 CFR §423.19 to ensure compliance under the Cessation of Coal Burning Activities subcategory – if this compliance pathway is being considered, and/or

2) commence the engineering and design process for implementation of the selected ELG-compliant technology and submit a status report on this process – if this compliance pathway is being considered.

d. On or before December 31, 2023, the permittee shall submit to the Department a report identifying the final pathway selected for compliance with the Final Rule: either the Cessation of Coal Burning Activities subcategory (including the annual progress report in accordance with 40 CFR §423.19), or the implementation of an ELG-compliant technology.

e. On or before December 31, 2024, the permittee shall:

1) submit an annual progress report in accordance with 40 CFR §423.19 to ensure compliance under the Cessation of Coal Burning Activities subcategory – if this compliance pathway was selected, or

2) continue construction of the selected ELG-compliant technology and submit a construction status report that includes a description of any impediments to final implementation by December 31, 2025 – if this compliance pathway was selected.

f. On or before December 31, 2025, the permittee shall:

1) submit an annual progress report in accordance with 40 CFR §423.19 to ensure compliance under the Cessation of Coal Burning Activities subcategory – if this compliance pathway was selected, or

2) submit an Initial Certification Statement in accordance with 40 CFR §423.19(c) and comply with the requirements set forth in Part I.A.14.b. of this permit – if the ELG-compliant technology pathway was selected.

g. If the permittee selected the Cessation of Coal Burning Activities subcategory as the final pathway for compliance with the Final Rule, the permittee shall complete the following:

1) On or before December 31, 2026, the permittee shall submit an annual progress report in accordance with 40 CFR §423.19 to ensure compliance under the Cessation of Coal Burning Activities subcategory.

2) On or before December 31, 2027, the permittee shall submit an annual progress report in accordance with 40 CFR §423.19 to ensure compliance under the Cessation of Coal Burning Activities subcategory.

3) On or before December 31, 2028, the permittee shall comply with the requirements set forth in Part I.A.14.a. of this permit.

PART I

Section A. Limitations and Monitoring Requirements

14. Bottom Ash Transport Water Discharge Prohibition

a. If the permittee has certified to the Department the intention to pursue the Cessation of Coal Burning Activities subcategory as set forth in Part I.A.13. of this permit, then the discharge of all BATW shall comply with the final effluent limitations set forth in Part I.A.2. and Part I.A.4. of this permit until no later than December 31, 2028, by which date the permittee shall cease discharge of newly generated BATW from any outfall and the discharge of previously generated BATW shall comply with the final effluent limitations set forth in Part I.A.2. and Part I.A.4. of this permit.

b. Beginning December 31, 2025, the permittee is prohibited from discharging newly generated BATW from any outfall in accordance with 40 CFR 423.13(k)(1), except for those discharges to which paragraph (k)(2) applies. After December 31, 2025, any discharge volume of BATW shall be reduced or eliminated to the extent achievable using control measures that are technologically available and economically achievable in light of best industry practices. The total volume of BATW allowed to be discharged under (k)(2) shall be determined by the Department on a case-by-case basis and in no event shall such discharge exceed a 30-day rolling average of 10 percent of the primary active wetted bottom ash system volume. At least 180 days prior to the discharge of any newly generated BATW, the permittee shall submit to the Department all information required under 40 CFR 423.19(c) for reviews required under (k)(2).

The Department may modify or reissue this permit in accordance with applicable rules in order to establish the permit requirements set forth in the rules for 40 CFR Part 423, Steam Electric Power Generating Point Source Category.

PART I

Section B. Storm Water Pollution Prevention

1. Final Effluent Limitations and Monitoring Requirements

The permittee is authorized to discharge storm water associated with industrial activity, as defined under 40 CFR 122.26(b)(14)(i-ix), to the surface waters of the state. Such discharge shall be limited and monitored by the permittee as specified below.

a. Narrative Standard
The receiving water shall contain no turbidity, color, oil films, floating solids, foams, settleable solids, suspended solids, or deposits as a result of this discharge in unnatural quantities which are or may become injurious to any designated use.

b. Visual Assessment of Storm Water Discharges
To ensure that storm water discharges from the facility do not violate the narrative standard in the receiving waters, storm water discharges shall be visually assessed in accordance with this permit.

c. Implementation of Storm Water Pollution Prevention Plan
The permittee shall implement an acceptable Storm Water Pollution Prevention Plan (SWPPP) as required by this permit.

d. Certified Operator
The permittee shall have an Industrial Storm Water Certified Operator who has supervision over the facility's storm water treatment and control measures included in the SWPPP.

PART I

Section B. Storm Water Pollution Prevention

The Storm Water Pollution Prevention Plan (SWPPP) is a written procedure to reduce the exposure of storm water to significant materials and to reduce the amount of significant materials in the storm water discharge. An acceptable SWPPP shall identify potential sources of contamination and describe the controls necessary to reduce their impacts in accordance with Part I.B.2. through Part I.B.8. of this permit.

2. Source Identification

To identify potential sources of significant materials that can pollute storm water and subsequently be discharged from the facility, the SWPPP shall, at a minimum, include the following:

a. A site map identifying:

1) buildings and other permanent structures;

2) storage or disposal areas for significant materials;

3) secondary containment structures and descriptions of the significant materials contained within the primary containment structures;

4) storm water discharge points (which include outfalls and points of discharge), numbered or otherwise labeled for reference;

5) location of storm water and non-storm water inlets (numbered or otherwise labeled for reference) contributing to each discharge point;

6) location of NPDES-permitted discharges other than storm water;

7) outlines of the drainage areas contributing to each discharge point;

8) structural controls or storm water treatment facilities;

9) areas of vegetation (with brief descriptions such as lawn, old field, marsh, wooded, etc.);

10) areas of exposed and/or erodible soils and gravel lots;

11) impervious surfaces (e.g., roofs, asphalt, concrete, etc.);

12) name and location of receiving water(s); and

13) areas of known or suspected impacts on surface waters as designated under Part 201 (Environmental Response) of the NREPA.

b. A list of all significant materials that could pollute storm water. For each material listed, the SWPPP shall include each of the following descriptions:

1) the ways in which each type of significant material has been, or has reasonable potential to become, exposed to storm water (e.g., spillage during handling; leaks from pipes, pumps, and vessels; contact with storage piles, contaminated materials, or soils; waste handling and disposal; deposits from dust or overspray; etc.);

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Section B. Storm Water Pollution Prevention

2) identification of the discharge point(s) and the inlet(s) contributing the significant material to each discharge point through which the significant material may be discharged if released; and

3) an evaluation of the reasonable potential for contribution of significant materials to storm water from at least the following areas or activities:

a) loading, unloading, and other significant material-handling operations;

b) outdoor storage, including secondary containment structures;

c) outdoor manufacturing or processing activities;

d) significant dust- or particulate-generating processes;

e) discharge from vents, stacks, and air emission controls;

f) on-site waste disposal practices;

g) maintenance and cleaning of vehicles, machines, and equipment;

h) areas of exposed and/or erodible soils;

i) Sites of Environmental Contamination listed under Part 201 (Environmental Response) of the NREPA;

j) areas of significant material residues;

k) areas where animals (wild or domestic) congregate and deposit wastes; and

l) other areas where storm water may come into contact with significant materials.

c. A listing of significant spills and significant leaks of polluting materials that occurred in areas that are exposed to precipitation or that discharge to a point source at the facility. The listing shall include spills that occurred over the three (3) years prior to the effective date of a permit authorizing discharge. The listing shall include the date, volume, and exact location of the release, and the action taken to clean up the material and/or prevent exposure to storm water or contamination of surface waters of the state. Any release that occurs after the SWPPP has been developed shall be controlled in accordance with the SWPPP and is cause for the SWPPP to be updated as appropriate within 14 calendar days of obtaining knowledge of the spill or loss.

d. A determination as to whether its facility discharges storm water to a water body for which an EPA-approved Total Maximum Daily Load (TMDL) has been established. If so, the permittee shall assess whether the TMDL requirements for the facility's discharge are being met through the existing SWPPP controls or whether additional control measures are necessary. The permitee's assessment of whether the TMDL requirements are being met shall focus on the effectiveness, adequacy, and implementation of the permitee's SWPPP controls.

e. A summary of existing storm water discharge sampling data (if available), describing pollutants in storm water discharges at the facility. This summary shall be accompanied by a description of the suspected source(s) of the pollutants detected.

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Section B. Storm Water Pollution Prevention

3. Nonstructural Controls

To prevent significant materials from contacting storm water at the source, the SWPPP shall, at a minimum, include each of the following nonstructural controls:

a. Written procedures and a schedule for routine preventive maintenance. Preventive maintenance procedures shall describe routine inspections and maintenance of storm water management and control devices (e.g., cleaning of oil/water separators and catch basins, routine housekeeping activities, etc.), as well as inspecting and testing plant equipment and systems to uncover conditions that could cause breakdowns or failures resulting in discharges of pollutants to the storm sewer system or the surface waters of the state. The routine inspection shall include areas of the facility in which significant materials have the reasonable potential to contaminate storm water. A written report of the inspection and corrective actions shall be retained in accordance with Record Keeping, below.

b. Written procedures and a schedule for good housekeeping to maintain a clean, orderly facility. Good housekeeping procedures shall include routine inspections that focus on the areas of the facility that have a reasonable potential to contaminate storm water entering the property. The routine housekeeping inspections may be combined with the routine inspections for the preventive maintenance program. A written report of the inspection and corrective actions shall be retained in accordance with Record Keeping, below.

c. Written procedures and a schedule for **quarterly** comprehensive site inspections, to be conducted by the Industrial Storm Water Certified Operator. At a minimum, one inspection shall be performed within each of the following quarters: January-March, April-June, July-September, and October-December. The comprehensive site inspections shall include, but not be limited to, inspection of structural controls in use at the facility, and the areas and equipment identified in the routine preventive maintenance and good housekeeping procedures. These inspections shall also include a review of the routine preventive maintenance reports, good housekeeping inspection reports, and any other paperwork associated with the SWPPP. The permittee may request Department approval of an alternate schedule for comprehensive site inspections. A written report of the inspection and corrective actions shall be retained in accordance with Record Keeping, below, and the following shall be included on the comprehensive inspection form/report:

1) Date of the inspection.

2) Name(s), title(s), and certification number(s) of the personnel conducting the inspection.

3) Precipitation information (i.e., a description of recent rainfall/snowmelt events).

4) All observations relating to the implementation of control measures. Items to include if applicable:

a) updates on corrective actions implemented due to previously identified pollutant and/or discharge issues;

b) any evidence of, or the potential for, pollutants to discharge to the drainage system or receiving waters and the condition of and around the discharge point including flow dissipation measures needing maintenance or repairs;

c) any control measures needing maintenance or repairs; and

d) any additional control measures needed to comply with permit requirements.

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5) Any required revisions to the SWPPP resulting from the inspection.

6) A written certification stating the facility is in compliance with this permit and the SWPPP, or, if there are instances of noncompliance, they are identified.

7) Written procedures and a schedule for **quarterly** visual assessments of storm water discharges. At a minimum, one visual assessment shall be conducted within each of the following quarters: January-March, April-June, July-September, and October-December. These assessments shall be conducted as part of the comprehensive site inspection within one month of control measure observations made in accordance with 4), above. If the Department has approved an alternate schedule for the comprehensive site inspection, the visual assessment may likewise be conducted in accordance with the same approved alternate schedule.

The following are the requirements of the visual assessment. The permittee shall develop and clearly document, in writing, procedures for meeting these requirements:

a) Within six (6) months of the effective date of this permit, the permittee shall develop written procedures for conducting the visual assessment and incorporate these procedures into the SWPPP. If Qualified Personnel rather than an Industrial Storm Water Certified Operator will collect storm water samples, these procedures shall include a written description of the training given to these personnel to qualify them to collect the samples, as well as documentation verifying that these personnel have received this training. The first visual assessment shall be conducted in conjunction with the next occurring comprehensive inspection. If changes resulting in altered drainage patterns occur at the facility, the permittee shall modify the procedures for conducting the visual assessment in accordance with the requirements of Keeping SWPPPs Current, below, and these modifications shall be incorporated into the SWPPP prior to conducting the next visual assessment.

b) A visual assessment shall be conducted of a representative storm water **sample** collected **from each storm water discharge point**. Storm water samples shall be visually assessed for conditions that could cause a violation of water quality standards as defined in Water Quality Standards, below. The visual assessment shall be made of the storm water sample in a clean, clear glass or plastic container. Only an Industrial Storm Water Certified Operator shall conduct this visual assessment. Visual assessment of the storm water sample shall be conducted within 48 hours of sample collection.

Representative storm water samples shall be collected:

(1) from each storm water discharge point identified as set forth under Source Identification, above. These samples may be collected by one or more of the following: an Industrial Storm Water Certified Operator; and/or an individual who meets qualifications acceptable to the Department and who is authorized by an Industrial Storm Water Certified Operator to collect the sample (“Qualified Personnel”); and/or an automated sampling device; and

(2) within the first 30 minutes of the start of a discharge from a storm event and on discharges that occur at least 72 hours (3 days) from the previous discharge. If it is not possible to collect the sample within the first 30 minutes of discharge, the sample shall be collected as soon thereafter as practicable, but not exceeding 60 minutes. In the case of snowmelt, samples shall be collected during a period with measurable discharge from the site.

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Section B. Storm Water Pollution Prevention

c) A visual assessment shall be conducted of the storm water **discharge at each storm water discharge point**. (If an automated sampling device is used to collect the storm water sample, this requirement is waived). Either an Industrial Storm Water Certified Operator and/or Qualified Personnel may conduct this visual assessment. This visual assessment may be conducted directly – by someone physically present at the storm water discharge at each storm water discharge point; or it may be conducted indirectly – through the use of a visual recording taken of the storm water discharge at each storm water discharge point. Direct visual assessment shall be conducted at the same time that the storm water sample is collected. Indirect visual assessment shall be conducted using a visual recording taken of the storm water discharge at the same time that the storm water sample was collected.

d) Visual assessments shall be documented. This documentation shall be retained in accordance with Record Keeping, below, and shall include the following:

(1) sampling location(s) at the storm water discharge point(s) identified on the site map (see Source Identification, above);

(2) storm event information (i.e., length of event expressed in hours, approximate size of event expressed in inches of precipitation, duration of time since previous event that caused a discharge, and date and time the discharge began);

(3) date and time of the visual assessment of each storm water **discharge** at each storm water discharge point;

(4) name(s) and title(s) of the Industrial Storm Water Certified Operator or Qualified Personnel who conducted the visual assessment of the storm water **discharge** at each storm water discharge point. If an automated sampling device was used to collect the storm water sample associated with this discharge point, this documentation requirement is waived;

(5) observations made during visual assessment of the storm water **discharge** at each storm water discharge point. If an automated sampling device was used to collect the storm water sample associated with this discharge point, this documentation requirement is waived;

(6) if applicable, any visual recordings used to conduct the visual assessment of the storm water **discharge** at each storm water discharge point;

(7) date and time of sample collection for each storm water **sample**;

(8) name(s) and title(s) of the Industrial Storm Water Certified Operator or Qualified Personnel who collected the storm water **sample**. If an automated sampling device was used to collect the storm water sample, the permittee shall document that, instead;

(9) date and time of the visual assessment of each storm water **sample**;

(10) name(s), title(s), and operator number(s) of the Industrial Storm Water Certified Operator(s) who conducted the visual assessment of each storm water **sample**;

(11) observations made during visual assessment of each storm water **sample**;

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(12) full-color photographic evidence of the storm water **sample** against a white background;

(13) nature of the discharge (i.e., rainfall or snowmelt);

(14) probable sources of any observed storm water contamination; and

(15) if applicable, an explanation for why it was not possible to collect samples within the first 30 minutes of discharge.

e) When adverse weather conditions prevent a visual assessment during the quarter, a substitute visual assessment shall be conducted during the next qualifying storm event. Documentation of the rationale for no visual assessment during a quarter shall be included with the SWPPP records as described in Record Keeping, below. Adverse conditions are those that are dangerous or create inaccessibility for personnel, such as local flooding, high winds, electrical storms, or situations that otherwise make sampling impractical such as drought or extended frozen conditions.

f) If the facility has two (2) or more discharge points that are believed to discharge substantially identical storm water effluents, the facility may conduct visual assessments of the discharge at just one (1) of the discharge points and report that the results also apply to the other substantially identical discharge point(s). The determination of substantially identical discharge points is to be based on the significant material evaluation conducted as set forth under Source Identification, above, and shall be clearly documented in the SWPPP. Visual assessments shall be conducted on a rotating basis of each substantially identical discharge point throughout the period of coverage under this permit.

d. A description of material handling procedures and storage requirements for significant materials. Equipment and procedures for cleaning up spills shall be identified in the SWPPP and made available to the appropriate personnel. The procedures shall identify measures to prevent spilled materials or material residues from contaminating storm water entering the property. The SWPPP shall include language describing what a reportable spill or release is and the appropriate reporting requirements in accordance with Part II.C.6. and Part II.C.7. The SWPPP may include, by reference, requirements of either a Pollution Incident Prevention Plan (PIPP) prepared in accordance with the Part 5 Rules (R 324.2001 through R 324.2009 of the Michigan Administrative Code); a Hazardous Waste Contingency Plan prepared in accordance with 40 CFR 264 and 265 Subpart D, as required by Part 111 of the NREPA; or a Spill Prevention Control and Countermeasure (SPCC) plan prepared in accordance with 40 CFR 112.

e. Identification of areas which, due to topography, activities, or other factors, have a high potential for significant soil erosion. Gravel lots shall be included. The SWPPP shall also identify measures used to control soil erosion and sedimentation.

f. A description of the employee training program that will be implemented on an annual basis to inform appropriate personnel at all levels of their responsibility as it relates to the components and goals of the SWPPP. The SWPPP shall identify periodic dates for the employee training program. Records of the employee training program shall be retained in accordance with Record Keeping, below.

g. Identification of actions to limit the discharge of significant materials in order to comply with TMDL requirements, if applicable.

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Section B. Storm Water Pollution Prevention

h. Identification of significant materials expected to be present in storm water discharges following implementation of nonstructural preventive measures and source controls.

4. Structural Controls

Where implementation of the measures required by Nonstructural Controls, above, does not control storm water discharges in accordance with Water Quality Standards, below, the SWPPP shall provide a description of the location, function, design criteria, and installation/construction schedule of structural controls for prevention and treatment. Structural controls may be necessary:

a. to prevent uncontaminated storm water from contacting, or being contacted by, significant materials; or

b. if preventive measures are not feasible or are inadequate to keep significant materials at the site from contaminating storm water. Structural controls shall be used to treat, divert, isolate, recycle, reuse, or otherwise manage storm water in a manner that reduces the level of significant materials in the storm water and provides compliance with water quality standards as identified in Water Quality Standards, below.

5. Keeping SWPPPs Current

a. The permittee and/or the Industrial Storm Water Certified Operator shall review the SWPPP annually after it is developed and maintain a written report of the review in accordance with Record Keeping, below. Based on the review, the permittee or the Industrial Storm Water Certified Operator shall amend the SWPPP as needed to ensure continued compliance with the terms and conditions of this permit. The written report shall be submitted to the Department on or before January 10th of each year.

b. The SWPPP developed under the conditions of a previous permit shall be amended as necessary to ensure compliance with this permit.

c. The SWPPP shall be updated or amended whenever changes at the facility have the potential to increase the exposure of significant materials to storm water, significant spills occur at the facility, or when the SWPPP is determined by the permittee or the Department to be ineffective in achieving the general objectives of controlling pollutants in storm water discharges associated with industrial activity. Updates based on increased activity or spills at the facility shall include a description of how the permittee intends to control any new sources of significant materials, or respond to and prevent spills in accordance with the requirements of this permit (see Source Identification; Nonstructural Controls; and Structural Controls, above).

d. The Department may notify the permittee at any time that the SWPPP does not meet minimum requirements of this permit. Such notification shall identify why the SWPPP does not meet minimum requirements of this permit. The permittee shall make the required changes to the SWPPP within 30 days after such notification from the Department or authorized representative and shall submit to the Department a written certification that the requested changes have been made.

e. Amendments to the SWPPP shall be signed and retained on-site with the SWPPP pursuant to Signature and SWPPP Review, below.

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Section B. Storm Water Pollution Prevention

6. Industrial Storm Water Certified Operator Update

If the Industrial Storm Water Certified Operator is changed or an Industrial Storm Water Certified Operator is added, the permittee shall provide the name and certification number of the new Industrial Storm Water Certified Operator to the Department. If a facility has multiple Industrial Storm Water Certified Operators, the names and certification numbers of all shall be included in the SWPPP.

7. Signature and SWPPP Review

a. The SWPPP shall be reviewed and signed by the Industrial Storm Water Certified Operator(s) and by either the permittee or an authorized representative in accordance with 40 CFR 122.22. The SWPPP and associated records shall be retained on-site at the facility that generates the storm water discharge.

b. The permittee shall make the SWPPP, reports, log books, storm water discharge sampling data (if collected), and items required by Record Keeping, below, available upon request to the Department. The Department makes the non-confidential business portions of the SWPPP available to the public.

8. Record Keeping

The permittee shall maintain records of all SWPPP-related inspection and maintenance activities. Records shall also be kept describing incidents such as spills or other discharges that can affect the quality of storm water. All such records shall be retained for three (3) years. The following records are required by this permit (see Nonstructural Controls; and Keeping SWPPPs Current, above):

a. routine preventive maintenance inspection reports;

b. routine good housekeeping inspection reports;

c. comprehensive site inspection reports;

d. documentation of visual assessments;

e. employee training records; and

f. written summaries of the annual SWPPP review.

PART I

Section B. Storm Water Pollution Prevention

9. Water Quality Standards

At the time of discharge, there shall be no violation of water quality standards in the receiving waters as a result of the storm water discharge. This requirement includes, but is not limited to, the following conditions:

a. In accordance with R 323.1050 of the Part 4 Rules promulgated pursuant to Part 31 of the NREPA, the receiving waters shall not have any of the following unnatural physical properties as a result of this discharge in quantities which are, or may become, injurious to any designated use: turbidity, color, oil films, floating solids, foams, settleable solids, suspended solids, or deposits.

b. Any unusual characteristics of the discharge (i.e., unnatural turbidity, color, oil film, floating solids, foams, settleable solids, suspended solids, or deposits) shall be reported within 24 hours to the Department, followed by a written report within five (5) days detailing the findings of the investigation and the steps taken to correct the condition.

c. Any pollutant for which a level of control is specified to meet a TMDL established by the Department shall be controlled at the facility so that its discharge is reduced by/to the amount specified in the TMDL.

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Section B. Storm Water Pollution Prevention

10. Prohibition of Non-Storm Water Discharges

Discharges of material other than storm water shall be in compliance with an NPDES permit issued for the discharge. Storm water shall be defined to include all of the following non-storm water discharges, provided pollution prevention controls for the non-storm water component are identified in the SWPPP:

a. discharges from fire hydrant flushing;

b. potable water sources, including water line flushing;

c. water from fire system testing and fire-fighting training without burned materials or chemical fire suppressants;

d. irrigation drainage;

e. lawn watering;

f. routine building wash-down that does not use detergents or other compounds;

g. pavement wash waters where contamination by toxic or hazardous materials has not occurred (unless all contamination by toxic or hazardous materials has been removed) and where detergents are not used;

h. uncontaminated condensate from air conditioners, coolers, and other compressors and from the outside storage of refrigerated gases or liquids;

i. springs;

j. uncontaminated groundwater;

k. foundation or footing drains where flows are not contaminated with process materials such as solvents; and

l. discharges from fire-fighting activities. Discharges from fire-fighting activities are exempted from the requirement to be identified in the SWPPP.

11. Tracer Dye Discharges

This permit does not authorize the discharge of tracer dyes without approval from the Department. Requests to discharge tracer dyes shall be submitted to the Department in accordance with Rule 1097 (R 323.1097 of the Michigan Administrative Code).

PART II

Part II may include terms and /or conditions not applicable to discharges covered under this permit.

Section A. Definitions

Acute toxic unit (TU_A) means $100/LC_{50}$ where the LC_{50} is determined from a whole effluent toxicity (WET) test which produces a result that is statistically or graphically estimated to be lethal to 50% of the test organisms.

Annual monitoring frequency refers to a calendar year beginning on January 1 and ending on December 31. When required by this permit, an analytical result, reading, value or observation shall be reported for that period if a discharge occurs during that period.

Authorized public agency means a state, local, or county agency that is designated pursuant to the provisions of section 9110 of Part 91 of the NREPA to implement soil erosion and sedimentation control requirements with regard to construction activities undertaken by that agency.

Best management practices (BMPs) means structural devices or nonstructural practices that are designed to prevent pollutants from entering into storm water, to direct the flow of storm water, or to treat polluted storm water.

Bioaccumulative chemical of concern (BCC) means a chemical which, upon entering the surface waters, by itself or as its toxic transformation product, accumulates in aquatic organisms by a human health bioaccumulation factor of more than 1000 after considering metabolism and other physiochemical properties that might enhance or inhibit bioaccumulation. The human health bioaccumulation factor shall be derived according to R 323.1057(5). Chemicals with half-lives of less than 8 weeks in the water column, sediment, and biota are not BCCs. The minimum bioaccumulation concentration factor (BAF) information needed to define an organic chemical as a BCC is either a field-measured BAF or a BAF derived using the biota-sediment accumulation factor (BSAF) methodology. The minimum BAF information needed to define an inorganic chemical as a BCC, including an organometal, is either a field-measured BAF or a laboratory-measured bioconcentration factor (BCF). The BCCs to which these rules apply are identified in Table 5 of R 323.1057 of the Water Quality Standards.

Biosolids are the solid, semisolid, or liquid residues generated during the treatment of sanitary sewage or domestic sewage in a treatment works. This includes, but is not limited to, scum or solids removed in primary, secondary, or advanced wastewater treatment processes and a derivative of the removed scum or solids.

Bulk biosolids means biosolids that are not sold or given away in a bag or other container for application to a lawn or home garden.

Certificate of Coverage (COC) is a document, issued by the Department, which authorizes a discharge under a general permit.

Chronic toxic unit (TU_C) means $100/MATC$ or $100/IC_{25}$, where the maximum acceptable toxicant concentration (MATC) and IC_{25} are expressed as a percent effluent in the test medium.

Class B biosolids refers to material that has met the Class B pathogen reduction requirements or equivalent treatment by a Process to Significantly Reduce Pathogens (PSRP) in accordance with the Part 24 Rules. Processes include aerobic digestion, composting, anaerobic digestion, lime stabilization and air drying.

Combined sewer system is a sewer system in which storm water runoff is combined with sanitary wastes.

PART II

Section A. Definitions

Daily concentration is the sum of the concentrations of the individual samples of a parameter divided by the number of samples taken during any calendar day. If the parameter concentration in any sample is less than the quantification limit, regard that value as zero when calculating the daily concentration. The daily concentration will be used to determine compliance with any maximum and minimum daily concentration limitations (except for pH and dissolved oxygen). When required by the permit, report the maximum calculated daily concentration for the month in the "MAXIMUM" column under "QUALITY OR CONCENTRATION" on the Discharge Monitoring Reports (DMRs).

For pH, report the maximum value of any *individual* sample taken during the month in the "MAXIMUM" column under "QUALITY OR CONCENTRATION" on the DMRs and the minimum value of any *individual* sample taken during the month in the "MINIMUM" column under "QUALITY OR CONCENTRATION" on the DMRs. For dissolved oxygen, report the minimum concentration of any *individual* sample in the "MINIMUM" column under "QUALITY OR CONCENTRATION" on the DMRs.

Daily loading is the total discharge by weight of a parameter discharged during any calendar day. This value is calculated by multiplying the daily concentration by the total daily flow and by the appropriate conversion factor. The daily loading will be used to determine compliance with any maximum daily loading limitations. When required by the permit, report the maximum calculated daily loading for the month in the "MAXIMUM" column under "QUANTITY OR LOADING" on the DMRs.

Daily monitoring frequency refers to a 24-hour day. When required by this permit, an analytical result, reading, value or observation shall be reported for that period if a discharge occurs during that period.

Department means the Michigan Department of Environment, Great Lakes, and Energy.

Detection level means the lowest concentration or amount of the target analyte that can be determined to be different from zero by a single measurement at a stated level of probability.

Discharge means the addition of any waste, waste effluent, wastewater, pollutant, or any combination thereof to any surface water of the state.

EC_{50} means a statistically or graphically estimated concentration that is expected to cause 1 or more specified effects in 50% of a group of organisms under specified conditions.

Fecal coliform bacteria monthly
FOR WWSLs THAT COLLECT AND STORE WASTEWATER AND ARE AUTHORIZED TO DISCHARGE ONLY IN THE SPRING AND/OR FALL ON AN INTERMITTENT BASIS – Fecal coliform bacteria monthly is the geometric mean of all daily concentrations determined during a discharge event. Days on which no daily concentration is determined shall not be used to determine the calculated monthly value. The calculated monthly value will be used to determine compliance with the maximum monthly fecal coliform bacteria limitations. When required by the permit, report the calculated monthly value in the "AVERAGE" column under "QUALITY OR CONCENTRATION" on the DMR. If the period in which the discharge event occurred was partially in each of two months, the calculated monthly value shall be reported on the DMR of the month in which the last day of discharge occurred.

FOR ALL OTHER DISCHARGES – Fecal coliform bacteria monthly is the geometric mean of all daily concentrations determined during a reporting month. Days on which no daily concentration is determined shall not be used to determine the calculated monthly value. The calculated monthly value will be used to determine compliance with the maximum monthly fecal coliform bacteria limitations. When required by the permit, report the calculated monthly value in the "AVERAGE" column under "QUALITY OR CONCENTRATION" on the DMR.

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Fecal coliform bacteria 7-day
FOR WWSLs THAT COLLECT AND STORE WASTEWATER AND ARE AUTHORIZED TO DISCHARGE ONLY IN THE SPRING AND/OR FALL ON AN INTERMITTENT BASIS – Fecal coliform bacteria 7-day is the geometric mean of the daily concentrations determined during any 7 consecutive days of discharge during a discharge event. If the number of daily concentrations determined during the discharge event is less than 7 days, the number of actual daily concentrations determined shall be used for the calculation. Days on which no daily concentration is determined shall not be used to determine the value. The calculated 7-day value will be used to determine compliance with the maximum 7-day fecal coliform bacteria limitations. When required by the permit, report the maximum calculated 7-day geometric mean value for the month in the "MAXIMUM" column under "QUALITY OR CONCENTRATION" on the DMRs. If the 7-day period was partially in each of two months, the value shall be reported on the DMR of the month in which the last day of discharge occurred.

FOR ALL OTHER DISCHARGES – Fecal coliform bacteria 7-day is the geometric mean of the daily concentrations determined during any 7 consecutive days in a reporting month. If the number of daily concentrations determined is less than 7, the actual number of daily concentrations determined shall be used for the calculation. Days on which no daily concentration is determined shall not be used to determine the value. The calculated 7-day value will be used to determine compliance with the maximum 7-day fecal coliform bacteria limitations. When required by the permit, report the maximum calculated 7-day geometric mean for the month in the "MAXIMUM" column under "QUALITY OR CONCENTRATION" on the DMRs. The first calculation shall be made on day 7 of the reporting month, and the last calculation shall be made on the last day of the reporting month.

Flow-proportioned sample is a composite sample with the sample volume proportional to the effluent flow.

General permit means a National Pollutant Discharge Elimination System permit issued authorizing a category of similar discharges.

Geometric mean is the average of the logarithmic values of a base 10 data set, converted back to a base 10 number.

Grab sample is a single sample taken at neither a set time nor flow.

IC_{25} means the toxicant concentration that would cause a 25% reduction in a nonquantal biological measurement for the test population.

Illicit connection means a physical connection to a municipal separate storm sewer system that primarily conveys non-storm water discharges other than uncontaminated groundwater into the storm sewer; or a physical connection not authorized or permitted by the local authority, where a local authority requires authorization or a permit for physical connections.

Illicit discharge means any discharge to, or seepage into, a municipal separate storm sewer system that is not composed entirely of storm water or uncontaminated groundwater. Illicit discharges include non-storm water discharges through pipes or other physical connections; dumping of motor vehicle fluids, household hazardous wastes, domestic animal wastes, or litter; collection and intentional dumping of grass clippings or leaf litter; or unauthorized discharges of sewage, industrial waste, restaurant wastes, or any other non-storm water waste directly into a separate storm sewer.

Individual permit means a site-specific NPDES permit.

Inlet means a catch basin, roof drain, conduit, drain tile, retention pond riser pipe, sump pump, or other point where storm water or wastewater enters into a closed conveyance system prior to discharge off site or into waters of the state.

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Interference is a discharge which, alone or in conjunction with a discharge or discharges from other sources, both: 1) inhibits or disrupts the POTW, its treatment processes or operations, or its sludge processes, use or disposal; and 2) therefore, is a cause of a violation of any requirement of the POTW's NPDES permit (including an increase in the magnitude or duration of a violation) or, of the prevention of sewage sludge use or disposal in compliance with the following statutory provisions and regulations or permits issued thereunder (or more stringent state or local regulations): Section 405 of the Clean Water Act, the Solid Waste Disposal Act (SWDA) (including Title II, more commonly referred to as the Resource Conservation and Recovery Act (RCRA), and including state regulations contained in any state sludge management plan prepared pursuant to Subtitle D of the SWDA), the Clean Air Act, the Toxic Substances Control Act, and the Marine Protection, Research and Sanctuaries Act. [This definition does not apply to sample matrix interference].

Land application means spraying or spreading biosolids or a biosolids derivative onto the land surface, injecting below the land surface, or incorporating into the soil so that the biosolids or biosolids derivative can either condition the soil or fertilize crops or vegetation grown in the soil.

LC_{50} means a statistically or graphically estimated concentration that is expected to be lethal to 50% of a group of organisms under specified conditions.

Maximum acceptable toxicant concentration (MATC) means the concentration obtained by calculating the geometric mean of the lower and upper chronic limits from a chronic test. A lower chronic limit is the highest tested concentration that did not cause the occurrence of a specific adverse effect. An upper chronic limit is the lowest tested concentration which did cause the occurrence of a specific adverse effect and above which all tested concentrations caused such an occurrence.

Maximum extent practicable means implementation of best management practices by a public body to comply with an approved storm water management program as required by a national permit for a municipal separate storm sewer system, in a manner that is environmentally beneficial, technically feasible, and within the public body’s legal authority.

MGD means million gallons per day.

Monthly concentration is the sum of the daily concentrations determined during a reporting period divided by the number of daily concentrations determined. The calculated monthly concentration will be used to determine compliance with any maximum monthly concentration limitations. Days with no discharge shall not be used to determine the value. When required by the permit, report the calculated monthly concentration in the “AVERAGE” column under “QUALITY OR CONCENTRATION” on the DMR.

For minimum percent removal requirements, the monthly influent concentration and the monthly effluent concentration shall be determined. The calculated monthly percent removal, which is equal to 100 times the quantity [1 minus the quantity (monthly effluent concentration divided by the monthly influent concentration)], shall be reported in the "MINIMUM" column under "QUALITY OR CONCENTRATION" on the DMRs.

Monthly loading is the sum of the daily loadings of a parameter divided by the number of daily loadings determined during a reporting period. The calculated monthly loading will be used to determine compliance with any maximum monthly loading limitations. Days with no discharge shall not be used to determine the value. When required by the permit, report the calculated monthly loading in the “AVERAGE” column under “QUANTITY OR LOADING” on the DMR.

Monthly monitoring frequency refers to a calendar month. When required by this permit, an analytical result, reading, value or observation shall be reported for that period if a discharge occurs during that period.

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Municipal separate storm sewer means a conveyance or system of conveyances designed or used for collecting or conveying storm water which is not a combined sewer and which is not part of a publicly-owned treatment works as defined in the Code of Federal Regulations at 40 CFR 122.2.
Municipal separate storm sewer system (MS4) means all separate storm sewers that are owned or operated by the United States, a state, city, village, township, county, district, association, or other public body created by or pursuant to state law, having jurisdiction over disposal of sewage, industrial wastes, storm water, or other wastes, including special districts under state law, such as a sewer district, flood control district, or drainage district, or similar entity, or a designated or approved management agency under Section 208 of the Federal Act that discharges to the waters of the state. This term includes systems similar to separate storm sewer systems in municipalities, such as systems at military bases, large hospital or prison complexes, and highways and other thoroughfares. The term does not include separate storm sewers in very discrete areas, such as individual buildings.

National Pretreatment Standards are the regulations promulgated by or to be promulgated by the Federal Environmental Protection Agency pursuant to Section 307(b) and (c) of the Federal Act. The standards establish nationwide limits for specific industrial categories for discharge to a POTW.

No observed adverse effect level (NOAEL) means the highest tested dose or concentration of a substance which results in no observed adverse effect in exposed test organisms where higher doses or concentrations result in an adverse effect.

Noncontact cooling water is water used for cooling which does not come into direct contact with any raw material, intermediate product, by-product, waste product or finished product.

Nondomestic user is any discharger to a POTW that discharges wastes other than or in addition to water-carried wastes from toilet, kitchen, laundry, bathing or other facilities used for household purposes.

Outfall is the location at which a point source discharge enters the surface waters of the state.

Part 91 agency means an agency that is designated by a county board of commissioners pursuant to the provisions of section 9105 of Part 91 of the NREPA; an agency that is designated by a city, village, or township in accordance with the provisions of section 9106 of Part 91 of the NREPA; or the Department for soil erosion and sedimentation activities under Part 615, Part 631, or Part 632 pursuant to the provisions of section 9115 of Part 91 of the NREPA.

Part 91 permit means a soil erosion and sedimentation control permit issued by a Part 91 agency pursuant to the provisions of Part 91 of the NREPA.

Partially treated sewage is any sewage, sewage and storm water, or sewage and wastewater, from domestic or industrial sources that is treated to a level less than that required by the permittee's National Pollutant Discharge Elimination System permit, or that is not treated to national secondary treatment standards for wastewater, including discharges to surface waters from retention treatment facilities.

Point of discharge is the location of a point source discharge where storm water is discharged directly into a separate storm sewer system.

Point source discharge means a discharge from any discernible, confined, discrete conveyance, including but not limited to any pipe, ditch, channel, tunnel, conduit, well, discrete fissure, container, or rolling stock. Changing the surface of land or establishing grading patterns on land will result in a point source discharge where the runoff from the site is ultimately discharged to waters of the state.

Polluting material means any material, in solid or liquid form, identified as a polluting material under the Part 5 Rules (R 324.2001 through R 324.2009 of the Michigan Administrative Code).

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POTW is a publicly owned treatment work.

Pretreatment is reducing the amount of pollutants, eliminating pollutants, or altering the nature of pollutant properties to a less harmful state prior to discharge into a public sewer. The reduction or alteration can be by physical, chemical, or biological processes, process changes, or by other means. Dilution is not considered pretreatment unless expressly authorized by an applicable National Pretreatment Standard for a particular industrial category.
Public (as used in the MS4 individual permit) means all persons who potentially could affect the authorized storm water discharges, including, but not limited to, residents, visitors to the area, public employees, businesses, industries, and construction contractors and developers.

Public body means the United States; the state of Michigan; a city, village, township, county, school district, public college or university, or single-purpose governmental agency; or any other body which is created by federal or state statute or law.

Qualified Personnel means an individual who meets qualifications acceptable to the Department and who is authorized by an Industrial Storm Water Certified Operator to collect the storm water sample.

Qualifying storm event means a storm event causing greater than 0.1 inch of rainfall and occurring at least 72 hours after the previous measurable storm event that also caused greater than 0.1 inch of rainfall. Upon request, the Department may approve an alternate definition meeting the condition of a qualifying storm event.

Quantification level means the measurement of the concentration of a contaminant obtained by using a specified laboratory procedure calculated at a specified concentration above the detection level. It is considered the lowest concentration at which a particular contaminant can be quantitatively measured using a specified laboratory procedure for monitoring of the contaminant.

Quarterly monitoring frequency refers to a three month period, defined as January through March, April through June, July through September, and October through December. When required by this permit, an analytical result, reading, value or observation shall be reported for that period if a discharge occurs during that period.

Regional Administrator is the Region 5 Administrator, U.S. EPA, located at R-19J, 77 W. Jackson Blvd., Chicago, Illinois 60604.

Regulated area means the permittee's urbanized area, where urbanized area is defined as a place and its adjacent densely-populated territory that together have a minimum population of 50,000 people as defined by the United States Bureau of the Census and as determined by the latest available decennial census.

Secondary containment structure means a unit, other than the primary container, in which significant materials are packaged or held, which is required by State or Federal law to prevent the escape of significant materials by gravity into sewers, drains, or otherwise directly or indirectly into any sewer system or to the surface or ground waters of this state.

Separate storm sewer system means a system of drainage, including, but not limited to, roads, catch basins, curbs, gutters, parking lots, ditches, conduits, pumping devices, or man-made channels, which is not a combined sewer where storm water mixes with sanitary wastes, and is not part of a POTW.

Significant industrial user is a nondomestic user that: 1) is subject to Categorical Pretreatment Standards under 40 CFR 403.6 and 40 CFR Chapter I, Subchapter N; or 2) discharges an average of 25,000 gallons per day or more of process wastewater to a POTW (excluding sanitary, noncontact cooling and boiler blowdown wastewater); contributes a process waste stream which makes up five (5) percent or more of the average dry weather hydraulic or organic capacity of the POTW treatment plant; or is designated as such by the permittee as defined in 40 CFR 403.12(a) on the basis that the industrial user has a reasonable potential for adversely

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Section A. Definitions

affecting the POTW's treatment plant operation or violating any pretreatment standard or requirement (in accordance with 40 CFR 403.8(f)(6)).

Significant materials Significant Materials means any material which could degrade or impair water quality, including but not limited to: raw materials; fuels; solvents, detergents, and plastic pellets; finished materials such as metallic products; hazardous substances designated under Section 101(14) of Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) (see 40 CFR 372.65); any chemical the facility is required to report pursuant to Section 313 of Emergency Planning and Community Right-to-Know Act (EPCRA); polluting materials as identified under the Part 5 Rules (R 324.2001 through R 324.2009 of the Michigan Administrative Code); Hazardous Wastes as defined in Part 111 of the NREPA; fertilizers; pesticides; and waste products such as ashes, slag, and sludge that have the potential to be released with storm water discharges.

Significant spills and significant leaks means any release of a polluting material reportable under the Part 5 Rules (R 324.2001 through R 324.2009 of the Michigan Administrative Code).

Special-use area means secondary containment structures required by state or federal law; lands on Michigan's List of Sites of Environmental Contamination pursuant to Part 201, Environmental Remediation, of the NREPA; and/or areas with other activities that may contribute pollutants to the storm water for which the Department determines monitoring is needed.

Stoichiometric means the quantity of a reagent calculated to be necessary and sufficient for a given chemical reaction.

Storm water means storm water runoff, snow melt runoff, surface runoff and drainage, and non-storm water included under the conditions of this permit.

Storm water discharge point is the location where the point source discharge of storm water is directed to surface waters of the state or to a separate storm sewer. It includes the location of all point source discharges where storm water exits the facility, including *outfalls* which discharge directly to surface waters of the state, and *points of discharge* which discharge directly into separate storm sewer systems.

SWPPP means the Storm Water Pollution Prevention Plan prepared in accordance with this permit.

Tier I value means a value for aquatic life, human health or wildlife calculated under R 323.1057 of the Water Quality Standards using a tier I toxicity database.

Tier II value means a value for aquatic life, human health or wildlife calculated under R 323.1057 of the Water Quality Standards using a tier II toxicity database.

Total maximum daily loads (TMDLs) are required by the Federal Act for waterbodies that do not meet water quality standards. TMDLs represent the maximum daily load of a pollutant that a waterbody can assimilate and meet water quality standards, and an allocation of that load among point sources, nonpoint sources, and a margin of safety.

Toxicity reduction evaluation (TRE) means a site-specific study conducted in a stepwise process designed to identify the causative agents of effluent toxicity, isolate the sources of toxicity, evaluate the effectiveness of toxicity control options, and then confirm the reduction in effluent toxicity.

Water Quality Standards means the Part 4 Water Quality Standards promulgated pursuant to Part 31 of the NREPA, being R 323.1041 through R 323.1117 of the Michigan Administrative Code.

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Weekly monitoring frequency refers to a calendar week which begins on Sunday and ends on Saturday. When required by this permit, an analytical result, reading, value or observation shall be reported for that period if a discharge occurs during that period.

WWSL is a wastewater stabilization lagoon.

WWSL discharge event is a discrete occurrence during which effluent is discharged to the surface water up to 10 days of a consecutive 14 day period.

3-portion composite sample is a sample consisting of three equal-volume grab samples collected at equal intervals over an 8-hour period.

7-day concentration
FOR WWSLs THAT COLLECT AND STORE WASTEWATER AND ARE AUTHORIZED TO DISCHARGE ONLY IN THE SPRING AND/OR FALL ON AN INTERMITTENT BASIS – The 7-day concentration is the sum of the daily concentrations determined during any 7 consecutive days of discharge during a WWSL discharge event divided by the number of daily concentrations determined. If the number of daily concentrations determined during the WWSL discharge event is less than 7 days, the number of actual daily concentrations determined shall be used for the calculation. The calculated 7-day concentration will be used to determine compliance with any maximum 7-day concentration limitations. When required by the permit, report the maximum calculated 7-day concentration for the WWSL discharge event in the "MAXIMUM" column under "QUALITY OR CONCENTRATION" on the DMR. If the WWSL discharge event was partially in each of two months, the value shall be reported on the DMR of the month in which the last day of discharge occurred.

FOR ALL OTHER DISCHARGES – The 7-day concentration is the sum of the daily concentrations determined during any 7 consecutive days in a reporting month divided by the number of daily concentrations determined. If the number of daily concentrations determined is less than 7, the actual number of daily concentrations determined shall be used for the calculation. The calculated 7-day concentration will be used to determine compliance with any maximum 7-day concentration limitations in the reporting month. When required by the permit, report the maximum calculated 7-day concentration for the month in the "MAXIMUM" column under "QUALITY OR CONCENTRATION" on the DMR. The first 7-day calculation shall be made on day 7 of the reporting month, and the last calculation shall be made on the last day of the reporting month.

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7-day loading
FOR WWSLs THAT COLLECT AND STORE WASTEWATER AND ARE AUTHORIZED TO DISCHARGE ONLY IN THE SPRING AND/OR FALL ON AN INTERMITTENT BASIS – The 7-day loading is the sum of the daily loadings determined during any 7 consecutive days of discharge during a WWSL discharge event divided by the number of daily loadings determined. If the number of daily loadings determined during the WWSL discharge event is less than 7 days, the number of actual daily loadings determined shall be used for the calculation. The calculated 7-day loading will be used to determine compliance with any maximum 7-day loading limitations. When required by the permit, report the maximum calculated 7-day loading for the WWSL discharge event in the "MAXIMUM" column under "QUANTITY OR LOADING" on the DMR. If the WWSL discharge event was partially in each of two months, the value shall be reported on the DMR of the month in which the last day of discharge occurred

FOR ALL OTHER DISCHARGES – The 7-day loading is the sum of the daily loadings determined during any 7 consecutive days in a reporting month divided by the number of daily loadings determined. If the number of daily loadings determined is less than 7, the actual number of daily loadings determined shall be used for the calculation. The calculated 7-day loading will be used to determine compliance with any maximum 7-day loading limitations in the reporting month. When required by the permit, report the maximum calculated 7-day loading for the month in the "MAXIMUM" column under "QUANTITY OR LOADING" on the DMR. The first 7-day calculation shall be made on day 7 of the reporting month, and the last calculation shall be made on the last day of the reporting month.

24-hour composite sample is a flow-proportioned composite sample consisting of hourly or more frequent portions that are taken over a 24-hour period. A time-proportioned composite sample may be used upon approval of the Department if the permittee demonstrates it is representative of the discharge.

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Section B. Monitoring Procedures

1. Representative Samples

Samples and measurements taken as required herein shall be representative of the volume and nature of the monitored discharge.

2. Test Procedures

Test procedures for the analysis of pollutants shall conform to regulations promulgated pursuant to Section 304(h) of the Federal Act (40 CFR Part 136 – Guidelines Establishing Test Procedures for the Analysis of Pollutants), unless specified otherwise in this permit. **Test procedures used shall be sufficiently sensitive to determine compliance with applicable effluent limitations**. Requests to use test procedures not promulgated under 40 CFR Part 136 for pollutant monitoring required by this permit shall be made in accordance with the Alternate Test Procedures regulations specified in 40 CFR 136.4. These requests shall be submitted to the Section Manager of the Permits Section, Water Resources Division, Michigan Department of Environment, Great Lakes, and Energy, P.O. Box 30458, Lansing, Michigan, 48909-7958. The permittee may use such procedures upon approval.

The permittee shall periodically calibrate and perform maintenance procedures on all analytical instrumentation at intervals to ensure accuracy of measurements. The calibration and maintenance shall be performed as part of the permittee's laboratory Quality Control/Quality Assurance program.

3. Instrumentation

The permittee shall periodically calibrate and perform maintenance procedures on all monitoring instrumentation at intervals to ensure accuracy of measurements.

4. Recording Results

For each measurement or sample taken pursuant to the requirements of this permit, the permittee shall record the following information: 1) the exact place, date, and time of measurement or sampling; 2) the person(s) who performed the measurement or sample collection; 3) the dates the analyses were performed; 4) the person(s) who performed the analyses; 5) the analytical techniques or methods used; 6) the date of and person responsible for equipment calibration; and 7) the results of all required analyses.

5. Records Retention

All records and information resulting from the monitoring activities required by this permit including all records of analyses performed and calibration and maintenance of instrumentation and recordings from continuous monitoring instrumentation shall be retained for a minimum of three (3) years, or longer if requested by the Regional Administrator or the Department.

PART II

Section C. Reporting Requirements

1. Start-up Notification

If the permittee will not discharge during the first 60 days following the effective date of this permit, the permittee shall notify the Department within 14 days following the effective date of this permit, and then 60 days prior to the commencement of the discharge.

2. Submittal Requirements for Self-Monitoring Data

Part 31 of the NREPA (specifically Section 324.3110(7)); and R 323.2155(2) of Part 21, Wastewater Discharge Permits, promulgated under Part 31 of the NREPA, allow the Department to specify the forms to be utilized for reporting the required self-monitoring data. Unless instructed on the effluent limitations page to conduct "Retained Self-Monitoring," the permittee shall submit self-monitoring data via the Department's MiWaters system.

The permittee shall utilize the information provided on the MiWaters website, located at https://miwaters.deq.state.mi.us, to access and submit the electronic forms. Both monthly summary and daily data shall be submitted to the Department no later than the 20th day of the month following each month of the authorized discharge period(s). The permittee may be allowed to submit the electronic forms after this date if the Department has granted an extension to the submittal date.

3. Retained Self-Monitoring Requirements

If instructed on the effluent limits page (or otherwise authorized by the Department in accordance with the provisions of this permit) to conduct retained self-monitoring, the permittee shall maintain a year-to-date log of retained self-monitoring results and, upon request, provide such log for inspection to the staff of the Department. Retained self-monitoring results are public information and shall be promptly provided to the public upon request.

The permittee shall certify, in writing, to the Department, on or before January 10th (April 1st for animal feeding operation facilities) of each year, that: 1) all retained self-monitoring requirements have been complied with and a year-to-date log has been maintained; and 2) the application on which this permit is based still accurately describes the discharge. With this annual certification, the permittee shall submit a summary of the previous year's monitoring data. The summary shall include maximum values for samples to be reported as daily maximums and/or monthly maximums and minimum values for any daily minimum samples.

Retained self-monitoring may be denied to a permittee by notification in writing from the Department. In such cases, the permittee shall submit self-monitoring data in accordance with Part II.C.2., above. Such a denial may be rescinded by the Department upon written notification to the permittee. Reissuance or modification of this permit or reissuance or modification of an individual permittee's authorization to discharge shall not affect previous approval or denial for retained self-monitoring unless the Department provides notification in writing to the permittee.

4. Additional Monitoring by Permittee

If the permittee monitors any pollutant at the location(s) designated herein more frequently than required by this permit, using approved analytical methods as specified above, the results of such monitoring shall be included in the calculation and reporting of the values required in the Discharge Monitoring Report. Such increased frequency shall also be indicated.

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Section C. Reporting Requirements

Monitoring required pursuant to Part 41 of the NREPA or Rule 35 of the Mobile Home Park Commission Act (Act 96 of the Public Acts of 1987) for assurance of proper facility operation shall be submitted as required by the Department.

5. Compliance Dates Notification

Within 14 days of every compliance date specified in this permit, the permittee shall submit a *written* notification to the Department indicating whether or not the particular requirement was accomplished. If the requirement was not accomplished, the notification shall include an explanation of the failure to accomplish the requirement, actions taken or planned by the permittee to correct the situation, and an estimate of when the requirement will be accomplished. If a written report is required to be submitted by a specified date and the permittee accomplishes this, a separate written notification is not required.

6. Noncompliance Notification

Compliance with all applicable requirements set forth in the Federal Act, Parts 31 and 41 of the NREPA, and related regulations and rules is required. All instances of noncompliance shall be reported as follows:

a. 24-Hour Reporting
Any noncompliance which may endanger health or the environment (including maximum and/or minimum daily concentration discharge limitation exceedances) shall be reported, verbally, within 24 hours from the time the permittee becomes aware of the noncompliance. A written submission shall also be provided within five (5) days.

b. Other Reporting
The permittee shall report, in writing, all other instances of noncompliance not described in a. above at the time monitoring reports are submitted; or, in the case of retained self-monitoring, within five (5) days from the time the permittee becomes aware of the noncompliance.

Written reporting shall include: 1) a description of the discharge and cause of noncompliance; and 2) the period of noncompliance, including exact dates and times, or, if not yet corrected, the anticipated time the noncompliance is expected to continue, and the steps taken to reduce, eliminate and prevent recurrence of the noncomplying discharge.

7. Spill Notification

The permittee shall immediately report any release of any polluting material which occurs to the surface waters or groundwaters of the state, unless the permittee has determined that the release is not in excess of the threshold reporting quantities specified in the Part 5 Rules (R 324.2001 through R 324.2009 of the Michigan Administrative Code), by calling the Department at the number indicated on the second page of this permit (or, if this is a general permit, on the COC); or, if the notice is provided after regular working hours, call the Department's 24-hour Pollution Emergency Alerting System telephone number, 1-800-292-4706 (calls from **out-of-state** dial 1-517-373-7660).

Within ten (10) days of the release, the permittee shall submit to the Department a full written explanation as to the cause of the release, the discovery of the release, response (clean-up and/or recovery) measures taken, and preventive measures taken or a schedule for completion of measures to be taken to prevent reoccurrence of similar releases.

PART II

Section C. Reporting Requirements

8. Upset Noncompliance Notification

If a process "upset" (defined as an exceptional incident in which there is unintentional and temporary noncompliance with technology based permit effluent limitations because of factors beyond the reasonable control of the permittee) has occurred, the permittee who wishes to establish the affirmative defense of upset, shall notify the Department by telephone within 24 hours of becoming aware of such conditions; and within five (5) days, provide in writing, the following information:

a. that an upset occurred and that the permittee can identify the specific cause(s) of the upset;

b. that the permitted wastewater treatment facility was, at the time, being properly operated and maintained (note that an upset does not include noncompliance to the extent caused by operational error, improperly designed treatment facilities, inadequate treatment facilities, lack of preventive maintenance, or careless or improper operation); and

c. that the permittee has specified and taken action on all responsible steps to minimize or correct any adverse impact in the environment resulting from noncompliance with this permit.

No determination made during administrative review of claims that noncompliance was caused by upset, and before an action for noncompliance, is final administrative action subject to judicial review.

In any enforcement proceedings, the permittee, seeking to establish the occurrence of an upset, has the burden of proof.

9. Bypass Prohibition and Notification

a. Bypass Prohibition
Bypass is prohibited, and the Department may take an enforcement action, unless:

1) bypass was unavoidable to prevent loss of life, personal injury, or severe property damage;

2) there were no feasible alternatives to the bypass, such as the use of auxiliary treatment facilities, retention of untreated wastes, or maintenance during normal periods of equipment downtime. This condition is not satisfied if adequate backup equipment should have been installed in the exercise of reasonable engineering judgment to prevent a bypass; and

3) the permittee submitted notices as required under 9.b. or 9.c. below.

b. Notice of Anticipated Bypass
If the permittee knows in advance of the need for a bypass, it shall submit prior notice to the Department, if possible at least ten (10) days before the date of the bypass, and provide information about the anticipated bypass as required by the Department. The Department may approve an anticipated bypass, after considering its adverse effects, if it will meet the three (3) conditions listed in 9.a. above.

c. Notice of Unanticipated Bypass
The permittee shall submit notice to the Department of an unanticipated bypass by calling the Department at the number indicated on the second page of this permit (if the notice is provided after regular working hours, use the following number: 1-800-292-4706) as soon as possible, but no later than 24 hours from the time the permittee becomes aware of the circumstances.

PART II

Section C. Reporting Requirements

d. Written Report of Bypass
A written submission shall be provided within five (5) working days of commencing any bypass to the Department, and at additional times as directed by the Department. The written submission shall contain a description of the bypass and its cause; the period of bypass, including exact dates and times, and if the bypass has not been corrected, the anticipated time it is expected to continue; steps taken or planned to reduce, eliminate, and prevent reoccurrence of the bypass; and other information as required by the Department.

e. Bypass Not Exceeding Limitations
The permittee may allow any bypass to occur which does not cause effluent limitations to be exceeded, but only if it also is for essential maintenance to ensure efficient operation. These bypasses are not subject to the provisions of 9.a., 9.b., 9.c., and 9.d., above. This provision does not relieve the permittee of any notification responsibilities under Part II.C.11. of this permit.

f. Definitions

1) Bypass means the intentional diversion of waste streams from any portion of a treatment facility.

2) Severe property damage means substantial physical damage to property, damage to the treatment facilities which causes them to become inoperable, or substantial and permanent loss of natural resources which can reasonably be expected to occur in the absence of a bypass. Severe property damage does not mean economic loss caused by delays in production.

10. Bioaccumulative Chemicals of Concern (BCC)

Consistent with the requirements of R 323.1098 and R 323.1215 of the Michigan Administrative Code, the permittee is prohibited from undertaking any action that would result in a lowering of water quality from an increased loading of a BCC unless an increased use request and antidegradation demonstration have been submitted and approved by the Department.

11. Notification of Changes in Discharge

The permittee shall notify the Department, in writing, as soon as possible but no later than 10 days of knowing, or having reason to believe, that any activity or change has occurred or will occur which would result in the discharge of: 1) detectable levels of chemicals on the current Michigan Critical Materials Register, priority pollutants or hazardous substances set forth in 40 CFR 122.21, Appendix D, or the Pollutants of Initial Focus in the Great Lakes Water Quality Initiative specified in 40 CFR 132.6, Table 6, which were not acknowledged in the application or listed in the application at less than detectable levels; 2) detectable levels of any other chemical not listed in the application or listed at less than detection, for which the application specifically requested information; or 3) any chemical at levels greater than five times the average level reported in the complete application (see the first page of this permit, for the date(s) the complete application was submitted). Any other monitoring results obtained as a requirement of this permit shall be reported in accordance with the compliance schedules.

PART II

Section C. Reporting Requirements

12. Changes in Facility Operations

Any anticipated action or activity, including but not limited to facility expansion, production increases, or process modification, which will result in new or increased loadings of pollutants to the receiving waters must be reported to the Department by a) submission of an increased use request (application) and all information required under R 323.1098 (Antidegradation) of the Water Quality Standards or b) by notice if the following conditions are met: 1) the action or activity will not result in a change in the types of wastewater discharged or result in a greater quantity of wastewater than currently authorized by this permit; 2) the action or activity will not result in violations of the effluent limitations specified in this permit; 3) the action or activity is not prohibited by the requirements of Part II.C.10.; and 4) the action or activity will not require notification pursuant to Part II.C.11. Following such notice, the permit or, if applicable, the facility's COC may be modified according to applicable laws and rules to specify and limit any pollutant not previously limited.

13. Transfer of Ownership or Control

In the event of any change in control or ownership of facilities from which the authorized discharge emanates, the permittee shall submit to the Department 30 days prior to the actual transfer of ownership or control a written agreement between the current permittee and the new permittee containing: 1) the legal name and address of the new owner; 2) a specific date for the effective transfer of permit responsibility, coverage and liability; and 3) a certification of the continuity of or any changes in operations, wastewater discharge, or wastewater treatment.

If the new permittee is proposing changes in operations, wastewater discharge, or wastewater treatment, the Department may propose modification of this permit in accordance with applicable laws and rules.

14. Operations and Maintenance Manual

For wastewater treatment facilities that serve the public (and are thus subject to Part 41 of the NREPA), Section 4104 of Part 41 and associated Rule 2957 of the Michigan Administrative Code allow the Department to require an Operations and Maintenance (O&M) Manual from the facility. An up-to-date copy of the O&M Manual shall be kept at the facility and shall be provided to the Department upon request. The Department may review the O&M Manual in whole or in part at its discretion and require modifications to it if portions are determined to be inadequate.

At a minimum, the O&M Manual shall include the following information: permit standards; descriptions and operation information for all equipment; staffing information; laboratory requirements; record keeping requirements; a maintenance plan for equipment; an emergency operating plan; safety program information; and copies of all pertinent forms, as-built plans, and manufacturer's manuals.

Certification of the existence and accuracy of the O&M Manual shall be submitted to the Department at least sixty days prior to start-up of a new wastewater treatment facility. Recertification shall be submitted sixty days prior to start-up of any substantial improvements or modifications made to an existing wastewater treatment facility.

PART II

Section C. Reporting Requirements

15. Signatory Requirements

All applications, reports, or information submitted to the Department in accordance with the conditions of this permit and that require a signature shall be signed and certified as described in the Federal Act and the NREPA.

The Federal Act provides that any person who knowingly makes any false statement, representation, or certification in any record or other document submitted or required to be maintained under this permit, including monitoring reports or reports of compliance or noncompliance, shall, upon conviction, be punished by a fine of not more than $10,000 per violation, or by imprisonment for not more than 6 months per violation, or by both.

The NREPA (Section 3115(2)) provides that a person who at the time of the violation knew or should have known that he or she discharged a substance contrary to this part, or contrary to a permit, COC, or order issued or rule promulgated under this part, or who intentionally makes a false statement, representation, or certification in an application for or form pertaining to a permit or COC or in a notice or report required by the terms and conditions of an issued permit or COC, or who intentionally renders inaccurate a monitoring device or record required to be maintained by the Department, is guilty of a felony and shall be fined not less than $2,500.00 or more than $25,000.00 for each violation. The court may impose an additional fine of not more than $25,000.00 for each day during which the unlawful discharge occurred. If the conviction is for a violation committed after a first conviction of the person under this subsection, the court shall impose a fine of not less than $25,000.00 per day and not more than $50,000.00 per day of violation. Upon conviction, in addition to a fine, the court in its discretion may sentence the defendant to imprisonment for not more than 2 years or impose probation upon a person for a violation of this part. With the exception of the issuance of criminal complaints, issuance of warrants, and the holding of an arraignment, the circuit court for the county in which the violation occurred has exclusive jurisdiction. However, the person shall not be subject to the penalties of this subsection if the discharge of the effluent is in conformance with and obedient to a rule, order, permit, or COC of the Department. In addition to a fine, the attorney general may file a civil suit in a court of competent jurisdiction to recover the full value of the injuries done to the natural resources of the state and the costs of surveillance and enforcement by the state resulting from the violation.

16. Electronic Reporting

Upon notice by the Department that electronic reporting tools are available for specific reports or notifications, the permittee shall submit electronically all such reports or notifications as required by this permit.

PART II

Section D. Management Responsibilities

1. Duty to Comply

All discharges authorized herein shall be consistent with the terms and conditions of this permit. The discharge of any pollutant identified in this permit, more frequently than, or at a level in excess of, that authorized, shall constitute a violation of the permit.

It is the duty of the permittee to comply with all the terms and conditions of this permit. Any noncompliance with the Effluent Limitations, Special Conditions, or terms of this permit constitutes a violation of the NREPA and/or the Federal Act and constitutes grounds for enforcement action; for permit or Certificate of Coverage (COC) termination, revocation and reissuance, or modification; or denial of an application for permit or COC renewal.

It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

2. Operator Certification

The permittee shall have the waste treatment facilities under direct supervision of an operator certified at the appropriate level for the facility certification by the Department, as required by Sections 3110 and 4104 of the NREPA. Permittees authorized to discharge storm water shall have the storm water treatment and/or control measures under direct supervision of a storm water operator certified by the Department, as required by Section 3110 of the NREPA.

3. Facilities Operation

The permittee shall, at all times, properly operate and maintain all treatment or control facilities or systems installed or used by the permittee to achieve compliance with the terms and conditions of this permit. Proper operation and maintenance includes adequate laboratory controls and appropriate quality assurance procedures.

4. Power Failures

In order to maintain compliance with the effluent limitations of this permit and prevent unauthorized discharges, the permittee shall either:

a. provide an alternative power source sufficient to operate facilities utilized by the permittee to maintain compliance with the effluent limitations and conditions of this permit; or

b. upon the reduction, loss, or failure of one or more of the primary sources of power to facilities utilized by the permittee to maintain compliance with the effluent limitations and conditions of this permit, the permittee shall halt, reduce or otherwise control production and/or all discharge in order to maintain compliance with the effluent limitations and conditions of this permit.

5. Adverse Impact

The permittee shall take all reasonable steps to minimize or prevent any adverse impact to the surface waters or groundwaters of the state resulting from noncompliance with any effluent limitation specified in this permit including, but not limited to, such accelerated or additional monitoring as necessary to determine the nature and impact of the discharge in noncompliance.

PART II

Section D. Management Responsibilities

6. Containment Facilities

The permittee shall provide facilities for containment of any accidental losses of polluting materials in accordance with the requirements of the Part 5 Rules (R 324.2001 through R 324.2009 of the Michigan Administrative Code). For a Publicly Owned Treatment Work (POTW), these facilities shall be approved under Part 41 of the NREPA.

7. Waste Treatment Residues

Residuals (i.e. solids, sludges, biosolids, filter backwash, scrubber water, ash, grit, or other pollutants or wastes) removed from or resulting from treatment or control of wastewaters, including those that are generated during treatment or left over after treatment or control has ceased, shall be disposed of in an environmentally compatible manner and according to applicable laws and rules. These laws may include, but are not limited to, the NREPA, Part 31 for protection of water resources, Part 55 for air pollution control, Part 111 for hazardous waste management, Part 115 for solid waste management, Part 121 for liquid industrial wastes, Part 301 for protection of inland lakes and streams, and Part 303 for wetlands protection. Such disposal shall not result in any unlawful pollution of the air, surface waters or groundwaters of the state.

8. Right of Entry

The permittee shall allow the Department, any agent appointed by the Department, or the Regional Administrator, upon the presentation of credentials and, for animal feeding operation facilities, following appropriate biosecurity protocols:

a. to enter upon the permittee's premises where an effluent source is located or any place in which records are required to be kept under the terms and conditions of this permit; and

b. at reasonable times to have access to and copy any records required to be kept under the terms and conditions of this permit; to inspect process facilities, treatment works, monitoring methods and equipment regulated or required under this permit; and to sample any discharge of pollutants.

9. Availability of Reports

Except for data determined to be confidential under Section 308 of the Federal Act and Rule 2128 (R 323.2128 of the Michigan Administrative Code), all reports prepared in accordance with the terms of this permit, shall be available for public inspection at the offices of the Department and the Regional Administrator. As required by the Federal Act, effluent data shall not be considered confidential. Knowingly making any false statement on any such report may result in the imposition of criminal penalties as provided for in Section 309 of the Federal Act and Sections 3112, 3115, 4106 and 4110 of the NREPA.

10. Duty to Provide Information

The permittee shall furnish to the Department, within a reasonable time, any information which the Department may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit or the facility's COC, or to determine compliance with this permit. The permittee shall also furnish to the Department, upon request, copies of records required to be kept by this permit.

Where the permittee becomes aware that it failed to submit any relevant facts in a permit application, or submitted incorrect information in a permit application or in any report to the Department, it shall promptly submit such facts or information.

PART II

Section E. Activities Not Authorized by This Permit

1. Discharge to the Groundwaters

This permit does not authorize any discharge to the groundwaters. Such discharge may be authorized by a groundwater discharge permit issued pursuant to the NREPA.

2. POTW Construction

This permit does not authorize or approve the construction or modification of any physical structures or facilities at a POTW. Approval for the construction or modification of any physical structures or facilities at a POTW shall be by permit issued under Part 41 of the NREPA.

3. Civil and Criminal Liability

Except as provided in permit conditions on "Bypass" (Part II.C.9. pursuant to 40 CFR 122.41(m)), nothing in this permit shall be construed to relieve the permittee from civil or criminal penalties for noncompliance, whether or not such noncompliance is due to factors beyond the permittee's control, such as accidents, equipment breakdowns, or labor disputes.

4. Oil and Hazardous Substance Liability

Nothing in this permit shall be construed to preclude the institution of any legal action or relieve the permittee from any responsibilities, liabilities, or penalties to which the permittee may be subject under Section 311 of the Federal Act except as are exempted by federal regulations.

5. State Laws

Nothing in this permit shall be construed to preclude the institution of any legal action or relieve the permittee from any responsibilities, liabilities, or penalties established pursuant to any applicable state law or regulation under authority preserved by Section 510 of the Federal Act.

6. Property Rights

The issuance of this permit does not convey any property rights in either real or personal property, or any exclusive privileges, nor does it authorize violation of any federal, state or local laws or regulations, nor does it obviate the necessity of obtaining such permits, including any other Department of Environment, Great Lakes, and Energy permits, or approvals from other units of government as may be required by law.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-9

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

Exhibit 49

2025 Energy Innovation Dataset

Plant Id	Plant Name	Plant State	Operator Name	Balancing Authority Code	Planned Retirement Year	2020 Values									2021 Values									
						# of Generators	Avg Age	Nameplate Capacity (MW)	All Net Generation (MWh)	Capacity Factor (%)	Going Forward Costs ($/MWh)	Final Fixed and Variable O&M ($/MWh)	Final Fuel Cost ($/MWh)	Total Going Forward Cost ($/MWh)	Fuel Cost Source	# of Generators	Avg Age	Nameplate Capacity (MW)	All Net Generation (MWh)	Capacity Factor (%)	Going Forward Costs ($/MWh)	Final Fixed and Variable O&M ($/MWh)	Final Fuel Cost ($/MWh)	Total Going Forward Cost ($/MWh)	Fuel Cost Source	Total Cost Increase ($/MWh)	Percentage Cost Increase (%)
3	Barry	AL	Alabama Power Co	SOCO		2	54	1190.0	862,166	8.25	41.59	6.98	30.60	70.64	EIA	2	55	1190.0	3,870,545	37.05	7.99	7.16	33.09	48.74	EIA	21.90	45%
26	E C Gaston	AL	Alabama Power Co	SOCO		1	50	952.0	1,964,654	23.36	15.33	11.62	56.67	83.62	EIA	1	47	952.0	2,424,914	41.07	6.82	10.04	42.30	59.17	EIA	24.45	41%
60	Wheelan Energy Center	NE	City of Hastings - (NE)	SWPP		2	20	324.3	1,177,286	41.44	6.84	16.68	15.20	38.82	EIA	2	17	324.3	1,299,367	45.74	5.08	16.42	21.52	41.02	EIA	-2.19	-5%
108	Holcomb	KS	Sunflower Electric Power Corp	SWPP		1	41	348.7	1,159,092	37.94	8.55	10.90	16.72	36.16	EIA	1	38	348.7	1,596,571	52.27	5.05	9.42	14.32	28.78	EIA	9.38	33%
113	Childs	AZ	Arizona Public Service Co	APSC		2	49	420.9	1,209,775	32.66	9.16	8.18	29.91	47.26	EIA	2	49	420.9	1,926,547	51.64	5.43	7.67	25.10	37.60	EIA	9.66	26%
136	Cross	SC	South Carolina Public Service Authority	SC		4	25	2390.1	8,534,996	40.76	7.05	7.30	31.13	45.38	EIA	4	22	2390.1	7,356,688	35.14	7.07	6.22	29.07	42.36	EIA	3.02	7%
136	Seminole (FL)	FL	Seminole Electric Cooperative Inc	SEC		1	49	714.6	3,215,336	51.39	9.17	6.40	34.12	49.68	EIA	1	37	1429.2	6,550,658	52.33	5.05	5.63	25.18	36.07	EIA	3.62	10%
160	Apache Station	AZ	Arizona Electric Pwr Coop Inc	WALC		1	45	264.0	1,192,584	66.18	4.99	10.25	21.16	36.31	EIA	1	42	264.0	1,222,875	68.43	4.69	8.66	30.43	43.18	EIA	-6.88	-16%
163	GREC	OK	Grand River Dam Authority	SWPP	2036	1	54	504.0	955,054	21.63	26.31	8.28	24.70	58.82	EIA	1	55	504.0	1,214,996	33.34	11.33	7.15	17.58	36.06	EIA	22.55	63%
298	Limestone	TX	NRG Texas Power LLC	ERCO		2	38	1849.8	5,364,672	33.11	9.24	16.28	25.28	50.80	EIA Agg	2	35	1849.8	5,792,129	35.19	7.51	14.67	21.39	42.97	EIA Agg	7.83	18%
470	Comanche (CO)	CO	Public Service Co of Colorado	WACM	2035 (Unit 2), 2036 (Unit 3)	2	25	1252.9	5,674,675	51.71	5.58	7.38	17.03	29.97	EIA	3	26	1635.3	8,175,602	57.07	4.35	6.94	14.74	26.03	EIA	3.94	15%
515	Hayden	CO	Public Service Co of Colorado	PSCO	2028 (Unit 1), 2027 (Unit 2)	2	42	465.4	2,101,658	51.54	6.65	8.50	28.48	44.71	EIA	2	43	465.4	2,474,836	60.79	4.62	7.24	21.78	33.63	EIA	11.07	33%
564	Stanton Energy Center	FL	Orlando Utilities Comm	FMPP	2035 (Unit 1)	2	33	929.0	3,773,661	34.09	8.98	7.11	37.71	53.80	EIA	2	30	929.0	4,573,755	56.20	4.42	6.15	30.90	41.47	EIA	12.32	30%
594	Indian River Generating Station	DE	Indian River Operations Inc	PJM	2025	4	44.5	447.7	147,776	3.76	85.66	7.95	138.27	231.88	EIA Agg	1	41	445.5	264,647	7.29	38.44	6.87	49.23	94.54	EIA Agg	127.34	135%
602	Brandon Shores	MD	Brandon Shores LLC	PJM	2035	2	37	1270.2	3,168,467	18.07	16.93	13.22	43.56	73.71	EIA Agg	2	34	1270.2	2,476,805	19.58	12.84	11.42	32.34	56.60	EIA Agg	17.11	30%
628	Crystal River	FL	Duke Energy Florida, LLC	FRC		1	47	1478.4	1,262,305	25.10	12.88	8.61	32.66	54.14	EIA	1	38	1478.4	1,842,283	38.90	6.79	7.44	41.23	55.46	EIA	-1.32	-2%
645	Big Bend	FL	Tampa Electric Co			1	39	486.0	639,737	15.03	20.36	37.86	19.29	77.51	EIA	1	26	486.0	1,832,101	38.34	6.89	13.98	31.04	51.91	EIA	25.60	49%
667	Northside Generating Station	FL	JEA	JEA		2	51	580.0	304,796	17.90	19.11	7.39	40.06	66.76	EIA	2	52	580.0	1,823,464	31.15	9.51	6.39	49.10	65.00	EIA	1.76	3%
703	Bowen	GA	Georgia Power Co	SOCO		4	51	3494.0	16,712,354	34.95	9.81	11.28	50.96	72.04	EIA	4	48	3494.0	16,042,156	30.84	9.09	9.75	27.76	46.60	EIA	25.45	55%
876	Kincaid Generation LLC	IL	Dynegy Kincaid Generation	PJM	2027	2	57	1319.0	2,209,670	19.13	17.92	11.75	25.34	55.01	EIA Agg	2	54	1319.0	3,933,111	34.04	8.70	10.15	21.78	40.64	EIA Agg	14.37	35%
879	Powerton	IL	Midwest Generations EME LLC	PJM		2	51	1785.6	2,220,605	14.20	24.14	11.19	30.10	65.44	EIA Agg	2	48	1785.6	2,701,322	17.27	16.23	9.67	24.05	49.95	EIA Agg	15.49	31%
889	Baldwin Energy Complex	IL	Dynegy Midwest Generation Inc	MISO	2027	3	52	1239.6	5,667,388	58.79	5.83	12.26	23.72	41.53	EIA Agg	2	49	1239.6	5,281,139	52.45	4.69	10.60	20.34	35.63	EIA Agg	6.11	17%
963	Dallman	IL	City Springfield - (IL)			1	55	230.1	547,210	27.15	9.91	23.80	29.22	62.93	EIA	2	27	437.4	1,225,024	31.97	7.77	21.54	18.80	48.10	EIA	14.83	31%
976	Marion	IL	Southern Illinois Power Coop			3	61	69.0	632,679	72.93	4.91	8.79	55.55	69.26	EIA	3	58	69.0	625,673	72.15	4.19	7.59	22.79	34.49	EIA	34.80	101%
983	Clifty Creek	IN	Indiana Kentucky Electric Corp	PJM		6	69	1303.8	5,174,526	45.31	7.97	20.40	36.26	64.63	EIA	6	66	1303.8	5,034,223	44.08	7.08	17.63	26.40	51.12	EIA	13.52	26%
994	AES Petersburg	IN	IN Indiana	MISO		2	43	1341.8	1,987,398	15.42	12.76	6.81	26.41	49.65	EIA	3	43	1965.1	7,797,260	47.73	5.67	5.92	21.26	32.99	EIA	16.66	49%
997	Michigan City	IN	Northern Indiana Pub Serv Co	MISO	2028	1	50	540.0	924,047	19.54	17.54	13.68	27.56	59.12	EIA	1	47	540.0	1,485,339	31.48	8.92	11.82	24.60	45.35	EIA	13.77	30%
1001	Cayuga	IN	Duke Energy Indiana, LLC	SWPP		2	53	1002.0	4,012,776	45.13	7.95	12.14	28.76	48.87	EIA	2	50	1002.0	4,062,813	49.05	6.94	10.49	26.46	43.99	EIA	-4.88	-10%
1012	F B Culley	IN	Southern Indiana Gas & Elec Co	MISO	2035 (Unit 2)	2	53	368.9	1,806,162	55.95	6.13	23.04	28.57	57.74	EIA	2	50	368.9	2,116,170	65.55	4.29	19.92	25.10	49.30	EIA	8.44	17%
1073	Pierce Creek	IA	Interstate Power and Light Co	MISO		2	57	64.6	38,155	6.74	10.64	8.97	47.87	107.68	EIA	2	54	64.6	69,130	8.68	34.11	7.75	43.86	85.72	EIA	21.95	26%
1082	Walter Scott Jr Energy Center	IA	Midamerican Energy Co	PJM		4	27	1848.3	4,365,218	44.22	6.50	6.97	17.95	31.42	EIA	3	27	1848.3	6,262,644	44.87	5.64	6.02	14.39	26.05	EIA	5.37	21%
1091	George Neal North	IA	Midamerican Energy Co	MISO		1	49	564.1	750,002	14.66	22.13	11.19	27.84	61.16	EIA	1	46	564.1	1,702,451	33.27	8.42	9.67	17.43	35.52	EIA	25.64	72%
1104	Muscatine	IA	Board of Water Electric & Communications	MISO		2	47	275.5	5,616	22.87	14.18	10.90	26.79	51.87	EIA	4	43	290.5	676,207	37.97	7.38	9.42	27.66	44.48	EIA	7.39	17%
1241	La Cygne	KS	La Cygne	SWPP		2	49	1508.9	5,216,103	37.38	8.68	15.73	18.88	43.29	EIA	2	46	1508.9	6,390,767	43.63	6.14	13.59	15.36	35.10	EIA	8.19	23%
1250	Lawrence Energy Center	KS	Evergy Kansas Central, Inc	SWPP		2	53	517.0	1,177,231	25.96	13.19	6.85	23.74	43.78	EIA	2	52	517.0	1,888,665	41.71	7.10	5.82	17.95	30.88	EIA	12.90	41%
1356	E W Brown	KY	Kentucky Utilities Co	LGEE		1	53	464.0	1,320,473	32.49	10.55	9.75	32.70	53.00	EIA	1	50	464.0	932,832	22.95	13.90	8.43	24.56	45.88	EIA	7.11	16%
1356	Ghent	KY	Kentucky Utilities Co	LGEE		4	45	2225.0	10,543,291	54.07	6.09	11.27	24.33	41.50	EIA	4	42	2225.0	10,582,129	54.27	5.16	9.74	20.39	35.30	EIA	6.20	17%
1364	Mill Creek (KY)	KY	Louisville Gas & Electric Co	LGEE	2027 (Unit 2)	3	45	1361.7	6,096,034	51.10	6.35	16.26	26.03	48.64	EIA	4	44	1717.2	7,403,799	49.22	5.69	14.22	20.84	40.76	EIA	7.88	19%
1379	Shawnee	KY	Tennessee Valley Authority	TVA	2033	9	70	1175.5	5,799,838	60.04	9.03	21.79	19.14	49.94	EIA	9	67	1175.5	6,093,761	63.51	7.17	18.82	16.09	41.59	EIA	4.86	11%
1384	Cooper	KY	East Kentucky Power Coop, Inc	PJM		2	56	344.0	641,141	14.64	23.41	19.16	45.76	88.35	EIA	2	53	344.0	478,612	15.88	19.64	16.58	42.70	77.92	EIA	10.43	13%
1393	R D Nelson	LA	Entergy Louisiana LLC	MISO		4	43	1341.8	1,671,795	27.34	11.87	13.01	24.56	50.32	EIA	3	39	1341.8	1,210,031	28.62	9.30	11.66	24.49	45.47	EIA	4.85	11%
1715	J H Campbell	MI	Consumers Energy Co - (MI)	MISO	2035	3	50	1560.8	6,218,670	60.18	5.70	10.07	24.89	40.65	EIA	3	47	1560.8	8,271,415	60.30	4.63	8.71	20.30	33.64	EIA	7.01	21%
1723	Monroe (MI)	MI	DTE Electric Company	MISO	2032 (Units 1-2), 2028 (Units 3-4)	4	51	3278.8	13,116,464	45.68	7.51	9.56	29.92	45.99	EIA	4	48	3278.8	14,723,662	51.25	5.47	8.26	20.96	34.69	EIA	11.30	32%
1769	Clay Boswell	MN	ALLETE, Inc.	MISO		2	47	922.5	4,997,727	54.42	5.96	5.83	24.19	35.97	EIA	2	44	922.5	5,846,585	62.45	4.49	5.04	23.52	33.05	EIA	2.93	9%
1822	Miami Fort	OH	Northern States Power Co - Minnesota	MISO	2038	1	66	1066.4	543,656	10.38	34.61	16.28	31.78	73.98	EIA	1	63	1066.4	1,249,364	24.76	14.16	12.69	29.65	56.50	EIA	24.53	50%
2079	Hawthorn	MO	Evergy Metro	SWPP		1	55	569.0	2,291,631	45.96	7.46	14.91	17.75	39.21	EIA	1	52	569.0	2,635,990	52.88	5.92	12.11	15.12	33.84	EIA	6.37	19%
2153	Labadie	MO	Union Electric Co - (MO)	MISO		4	52	2389.4	14,491,714	69.51	4.68	6.36	21.75	27.34	EIA	4	49	2389.4	16,600,015	79.35	3.53	5.41	15.96	24.93	EIA	2.41	10%
2167	Sioux	MO	Union Electric Co - (MO)	MISO	2038	2	57	1099.4	3,337,571	34.66	8.89	15.65	21.65	47.39	EIA	2	54	1099.4	3,886,900	40.36	7.34	13.02	20.07	40.93	EIA	6.46	16%
2167	New Madrid	MO	Associated Electric Coop, Inc	AECI		2	50	1300.0	5,325,976	46.77	6.84	6.09	23.63	36.46	EIA	2	47	1300.0	5,649,269	49.61	5.65	5.26	20.22	31.13	EIA	5.32	17%
2168	Thomas Hill	MO	Associated Electric Coop, Inc	AECI		2	47	1181.7	5,126,592	53.68	6.06	5.46	29.42	32.14	EIA	2	44	1181.7	5,648,237	62.77	3.39	4.71	18.51	26.61	EIA	5.53	21%
2277	Sheldon	NE	Nebraska Public Power District	SWPP		2	61	224.7	653,156	32.60	11.08	25.60	17.14	53.82	EIA	2	58	224.7	844,659	42.16	7.02	22.13	16.84	45.99	EIA	7.83	17%
2291	North Omaha	NE	Omaha Public Power District	SWPP		4	54	3519.6	979,414	31.62	10.84	9.33	21.55	65.71	EIA	2	55	1014.6	1,726,771	52.23	5.67	7.20	14.29	27.16	EIA	13.55	50%
2364	Merrimack	NH	Granite Shore Power	ISNE		2	58	459.2	224,687	5.59	61.37	21.93	159.09	202.39	EIA Agg	2	55	459.2	284,416	7.07	81.88	18.96	46.59	167.42	EIA Agg	94.97	88%
2442	Four Corners	NM	Arizona Public Service Co	APSC	2031	5	38	1636.2	8,450,204	59.36	5.79	18.92	26.61	61.31	EIA	5	32	1636.2	7,964,157	55.15	5.37	16.35	21.04	52.76	EIA	8.55	16%
2712	Reidsons	NC	Duke Energy Progress - (NC)	CPLE		4	51	2558.2	6,775,236	30.23	11.34	10.32	48.43	70.09	EIA	4	49	2558.2	5,519,132	24.63	11.38	8.92	31.22	51.52	EIA	18.57	36%
2727	Marshall (NC)	NC	Duke Energy Carolinas, LLC	DUK	2034 (Unit 2)	4	51	1659.1	4,918,678	45.39	7.92	6.86	44.63	61.41	EIA	4	53	2159.0	6,897,413	37.16	7.97	6.66	26.14	42.18	EIA	19.23	46%
2817	Leland Olds	ND	Basin Electric Power Coop	SWPP		2	52	656.0	3,061,660	53.27	6.43	12.46	22.37	41.27	EIA	2	49	656.0	2,592,127	45.11	6.21	10.77	19.09	36.07	EIA	5.20	14%
2823	Milton R Young	ND	Minnkota Power Coop, Inc	MISO		2	43	734.0	4,240,329	67.50	4.81	7.67	26.95	39.42	EIA	2	40	734.0	4,473,693	69.80	4.03	6.63	19.82	30.48	EIA	8.94	29%
2828	Cardinal	OH	Cardinal Operating Company	PJM	2036 (Unit 3)	3	54	1888.4	9,697,135	57.66	5.95	14.27	26.76	46.98	EIA Agg	3	51	1888.4	10,066,943	61.11	4.85	12.34	16.33	33.51	EIA Agg	15.47	46%
2832	Miami Fort	OH	Dynegy Kincaid Generation	PJM	2027	2	47	1144.8	1,509,649	56.53	5.74	5.99	26.70	41.21	EIA Agg	2	44	1144.8	4,776,336	69.39	4.04	5.17	17.59	26.80	EIA Agg	14.41	54%
2836	Kyger Creek	OH	Ohio Valley Electric Corp	OVEC		5	69	1088.5	4,763,371	50.26	7.19	19.37	29.26	55.82	EIA	5	66	1088.5	5,034,291	52.89	5.90	16.74	20.09	42.73	EIA	13.09	31%
2952	Muskogee	OK	Oklahoma Gas & Electric Co	SWPP		1	46	572.0	509,739	10.17	31.88	8.28	32.95	73.11	EIA	1	47	572.0	2,778,163	55.65	4.77	7.16	29.60	42.55	EIA	40.56	125%
2963	Northeastern	OK	Public Service Co of Oklahoma	SWPP		1	45	473.0	1,220,830	31.88	10.18	6.66	26.03	44.87	EIA	1	42	473.0	2,326,823	56.16	4.99	5.76	18.40	29.15	EIA	15.72	54%
2964	Redbud	OK	Oklahoma Gas & Electric Co	SWPP		1	54	1811.0	1,066,696	20.99	16.33	14.24	20.37	60.94	EIA Agg	2	51	1811.0	7,262,671	42.56	6.97	12.31	21.67	40.94	EIA Agg	20.00	49%
3136	Keystone	PA	KeyCon Operating LLC	PJM		2	57	1872.0	3,042,420	18.55	16.48	8.58	31.81	56.86	EIA Agg	2	54	1872.0	7,415,681	45.23	6.55	7.41	21.09	35.05	EIA Agg	23.82	68%
3149	Talen Energy Montour	PA	Talen Energy Marketing LLC	PJM		2	52	1644.9	1,436,380	10.04	18.44	12.03	32.82	64.29	EIA Agg	2	49	1707.9	1,396,105	8.34	14.24	11.27	20.57	46.08	EIA Agg	-18.21	-28%
3167	Wateree	SC	Dominion Energy South Carolina, Inc	SCEG		2	54	771.8	3,241,668	33.16	10.34	9.91	43.70	63.95	EIA	2	51	771.8	1,098,649	23.31	13.27	8.56	31.43	53.27	EIA	10.68	20%
3298	Williams	SC	South Carolina Genertg Co, Inc	SCEG		1	51	659.7	1,898,619	32.65	10.43	18.47	31.66	60.36	EIA	1	48	659.7	2,433,125	42.10	6.66	12.90	33.09	52.64	EIA	27.72	53%
3399	Cumberland (TN)	TN	Tennessee Valley Authority	TVA	2038 (Unit 1), 2026 (Unit 2)	2	51	2600.0	9,511,813	41.76	8.21	10.60	26.75	47.55	EIA	2	48	2600.0	10,262,624	45.59	5.16	9.16	17.13	31.45	EIA	15.10	47%
3403	Gallatin (TN)	TN	Tennessee Valley Authority	TVA	2031	4	66	1255.2	4,096,720	37.28	9.69	7.59	29.43	46.72	EIA	4	63	1255.2	3,973,622	36.14	8.63	6.56	25.26	40.46	EIA Agg	6.25	15%
3407	Kingston	TN	Tennessee Valley Authority	TVA	2027	9	64	1700.0	3,466,569	23.24	15.54	22.34	39.04	76.82	EIA	9	66	1700.0	2,775,598	18.64	16.74	19.31	27.08	63.13	EIA	13.79	22%
3470	W A Parish	TX	NRG Texas Power LLC	ERCO		4	45	2736.8	10,675,949	42.03	7.72	7.01	26.27	41.00	EIA Agg	4	42	2736.8	13,173,360	54.95	5.10	6.18	21.68	32.84	EIA Agg	9.16	25%
3845	Tanasita Centralia Generation	WA	Tanasita Centralia LLC	BPAT	2025	1	51	729.9	3,831,764	44.39	7.74	6.26	20.65	46.87	EIA Agg	1	48	729.9	4,314,145	48.71	5.75	7.15	23.13	36.04	EIA Agg	9.83	23%
3935	John E Amos	WV	Appalachian Power Co	PJM		3	52	2932.6	9,613,014	37.42	9.16	12.68	37.01	58.85	EIA	3	49	2932.6	12,011,111	46.75	5.99	10.96	20.83	37.78	EIA	21.07	56%
3943	FirstEnergy Fort Martin Power Station	WV	Monongahela Power Co	PJM		2	51	1152.0	3,660,338	38.34	8.96	11.65	24.35	44.96	EIA	2	54	1152.0	5,206,498	51.61	5.74	9.55	24.02	39.31	EIA	5.05	13%
3944	FirstEnergy Harrison Power Station	WV	Monongahela Power Co	PJM		3	51	2052.0	10,618,152	59.07	5.80	6.31	20.29	32.40	EIA	3	48	2052.0	11,494,151	63.94	4.38	5.45	19.79	29.62	EIA	2.78	9%
3948	Mitchell (WV)	WV	Appalachian Power Co	PJM		2	53	1622.6	4,090,177	28.60	11.99	11.02	38.48	61.49	EIA	2	50	1622.6	4,769,164	33.35	8.89	9.52	21.38	39.79	EIA	21.70	55%
3954	Mt Storm	WV	Virginia Electric & Power Co	PJM		3	56	1662.4	4,160,693	28.07	12.00	19.45	40.65	72.10	EIA	3	53	1662.4	5,506,683	37.83	7.83	16.81	26.23	50.87	EIA	21.24	42%
3991	South Oak Creek	WI	Wisconsin Electric Power Co	MISO	2035	2	51	641.6	1,892,720	33.68	10.18	16.90	23.17	50.25	EIA	4	58	1340.0	4,475,795	41.29	7.19	14.36	20.79	42.34	EIA	7.91	19%
4050	Edgewater	WI	Wisconsin Power & Light Co	MISO		1	39	413.7	2,092,135	57.73	5.30	6.96	22.95	35.21	EIA	1	36	413.7	2,310,548	63.76	4.15	6.01	23.07	33.23	EIA	1.98	6%
4078	Weston	WI	Wisconsin Public Service Corp	MISO		2	46	945.5	3,981,205	48.07	5.98	7.22	22.26	35.47	EIA	2	43	945.5	4,733,736	57.39	4.33	6.24	21.17	31.74	EIA	3.73	12%
4158	Dave Johnston	WY	PacifiCorp	PACE	2027	4	58	816.7	3,839,647	53.66	6.39	5.66	14.53	26.59	EIA	4	55	922.2	3,601,242	44.58	6.64	4.90	11.84	23.38	EIA	3.21	14%
4162	Naughton	WY	PacifiCorp	PACE	2025	3	68	369.8	1,658,751	49.73	6.89	10.02	31.72	48.64	EIA	2	55	448.0	2,273,649	57.91	5.11	8.66	29.61	43.38	EIA	5.26	12%
4271	John P Madgett	WI	Dairyland Power Coop	MISO		1	45	387.0	914,277	26.97	12.03	17.65	33.69	63.37	EIA	1	42	387.0	1,721,629	50.78	5.52	15.25	26.42	47.19	EIA	16.38	35%
4602	James H Miller Jr	AL	Alabama Power Co	SOCO		4	12	2822.0	10,597,292	42.91	4.67	6.26	21.57	31.84	EIA	4	13	2822.0	12,723,665	63.04	3.16	5.36	18.13	26.73	EIA	5.11	19%
4804	Pleasants Power Station	WV	Omnis Pleasants, LLC	PJM		2	45	1368.0	955,020	7.97	40.70	9.49	36.54	86.73	EIA Agg	2	42	1368.0	7,582,771	63.28	4.43	8.20	20.47	33.10	EIA Agg	53.63	162%
6009	White Bluff	AR	Entergy Arkansas LLC	MISO		2	44	1980.0	2,645,196	12.97	25.01	8.34	24.66	57.91	EIA	2	41	1890.0	7,960,258	44.78	6.26	7.12	20.83	34.21	EIA	23.70	69%
6017	Newton	IL	Dynegy Midwest Generation Co	MISO	2027	2	43	617.4	2,821,884	52.17	6.22	10.39	23.82	40.43	EIA Agg	2	44	617.4	3,254,166	60.17	4.66	8.98	20.32	34.15	EIA Agg	6.28	18%
6018	East Bend	KY	Duke Energy Kentucky Inc	PJM		1	43	772.0	2,264,495	33.48	9.69	16.00	34.77	58.46	EIA	1	40	772.0	2,542,673	37.60	7.45	12.10	20.53	40.09	EIA	18.37	46%
6021	Craig (CO)	CO	Tri-State G & T Assn, Inc	WACM	2035 (Unit 1), 2028 (Unit 2), 2029 (Unit 3)	3	43	1427.4	6,512,666	56.09	8.99	6.13	34.17	49.29	EIA	3	40	1427.4	7,210,480	58.24	4.54	5.30	19.76	29.60	EIA	19.69	67%
6030	Coal Creek	ND	Ramboe Energy Center	MISO		2	45	1299.6	8,258,614	77.94	4.16	5.28	21.19	30.63	EIA	2	42	1299.6	8,970,990	84.66	3.31	4.57	16.77	24.65	EIA	5.99	24%
6034	Belle River	MI	DTE Electric Company	MISO	2028	2	46	1395.0	3,553,971	45.65	8.73	13.94	28.77	69.65	EIA	2	47	1395.0	6,865,645	56.35	4.69	10.11	21.79	36.59	EIA	12.85	26%
6041	H L Spurlock	KY	East Kentucky Power Coop, Inc	PJM		4	33	1616.5	7,633,686	54.19	5.65	16.38	32.66	54.68	EIA	4	30	1616.5	8,428,929	59.82	4.42	14.16	18.29	36.87	EIA	17.61	48%
6055	Big Cajun 2	LA	Louisiana Generating LLC	MISO		3	42	1736.9	661,027	7.70	42.14	8.89	39.60	90.62	EIA Agg	2	39	1736.9	2,216,841	22.86	13.55	7.68	28.12	47.35	EIA Agg	43.27	91%
6064	Newman Creek	WY	City of Kenai City - (KS)	SWPP		1	43	261.0	661,122	28.92	11.22	17.77	27.83	56.82	EIA	1	40	261.0	1,272,074	55.64	5.04	15.36	18.85	39.25	EIA	17.57	45%
6065	Iatan	MO	Evergy Kansas Central, Inc	SWPP		2	47	1703.9	4,033,814	36.21	10.95	6.97	21.37	39.30	EIA	2	44	1703.9	7,861,696	51.96	4.78	6.03	13.65	24.76	EIA	14.54	59%
6068	Jeffrey Energy Center	KS	Evergy Kansas Central, Inc	SWPP		3	44	2160.0	5,396,264	28.53	11.37	10.50	18.89	40.76	EIA	3

State	Increase in Coal Power Cost By State ($/MWh)	Weighted Avg Cost of Coal Power by State in 2024 ($/MWh)
AL	37.93393999	7.480297212
AR	41.90122231	5.944721732
AZ	56.51554642	14.08344442
CA		
CO	39.33535838	10.30820944
CT		
DC		
DE	221.8761029	127.3387759
FL	53.50549995	5.689998956
GA	66.71100175	19.00841935
IA	38.63343192	9.725805912
ID		
IL	38.81721467	7.571739858
IN	58.81188822	14.90842856
KS	42.54800667	9.509355837
KY	46.35093349	9.308201802
LA	63.2739221	18.79729695
MA		
MD	73.70844799	17.10580366
ME		
MI	45.07020455	10.30771609
MN	41.18833898	5.034647863
MO	34.34030065	5.707797427
MS	60.76349909	15.46149471
MT	41.0604362	7.122524784
NC	68.01818431	19.01343787
ND	34.53581284	6.265181942
NE	27.86386333	4.19594737
NH	202.3922844	94.96768747
NJ		
NM	61.31310294	8.548435411
NV	79.4294835	28.32650169
NY		
OH	48.82266897	13.98484121
OK	53.95115581	16.43031007
OR		
PA	60.74068094	17.62564958
RI		
SC	54.28073668	7.077291056
SD	46.0068521	9.695183185
TN	53.30676073	12.71282206
TX	39.11171011	6.261700769
UT	58.53091529	23.6707588

VA	89.18327645	31.34968258
VT		
WA	46.8715898	8.836472222
WI	40.58935338	5.864332044
WV	50.24364994	14.67356958
WY	33.81029024	4.901115837

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-9

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

Exhibit 50

2025 Energy Innovation Coal Cost Report

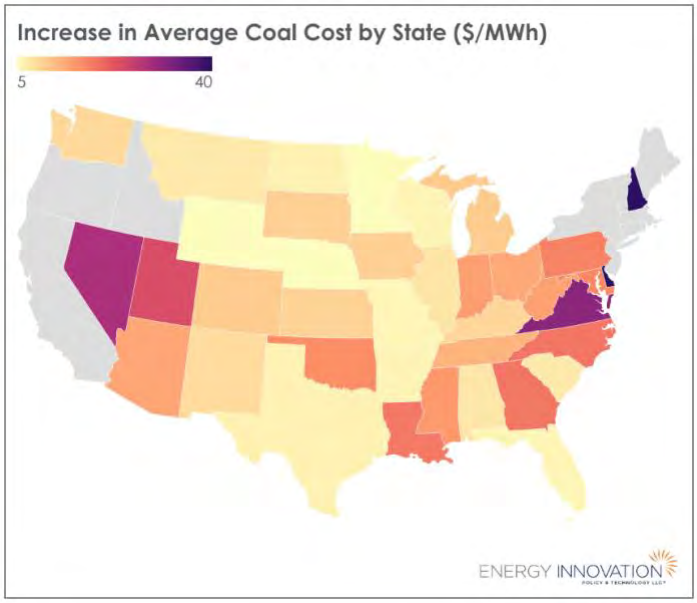
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COAL POWER 28 PERCENT MORE EXPENSIVE IN 2024 THAN IN 2021

Since 2021, the cost to generate coal power in the United States has increased faster than inflation, on average, meaning that coal is putting further inflationary pressure on American electricity consumers. This updated analysis on coal costs shows that in 2024, coal power was 28 percent more expensive than in 2021, costing consumers $6.2 billion more to generate power via coal than it would have cost in 2021.

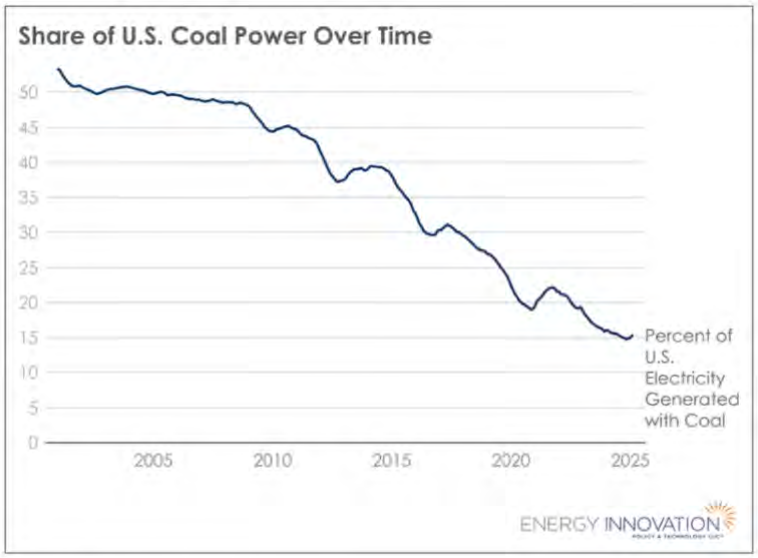
Coal power is declining across the United States, largely because of these poor economics. Total coal power use peaked in 2007 and has fallen ever since, generating barely 15 percent at the beginning of 2025. Between 2021 and the beginning of 2025, nearly 50 plants retired or are no longer burning coal, and over a third of the remaining fleet is expected to retire by 2030.[1]



This reality sits in stark contrast to U.S. federal power policy. The Trump administration issued a series of executive orders in April 2025 aiming to keep coal plants running despite their impact on electricity consumers. These include orders to reduce the number of plants subject to the U.S. Environmental Protection Agency's Mercury and Air Toxics Standards,[2] and to keep uneconomic plants running long-term using short-term emergency powers.[3] This has already resulted in a plant ordered to remain open – the J.H Campbell plant owned by Consumers Energy in Michigan which was scheduled to close May 31.[4]

[1] https://ieefa.org/resources/nowhere-go-down-us-coal-capacity-generation
[2] https://www.whitehouse.gov/presidential-actions/2025/04/rregulatory-relief-for-certain-stationary-sources-to-promote-american-energy/?utm_source=chatgpt.com
[3] https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliability-and-security-of-the-united-states-electric-grid/
[4] https://apnews.com/article/michigan-power-plant-coal-trump-aa6244ce5e7cca4326e582c849e0bc98

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Source: U.S. Energy Information Administration

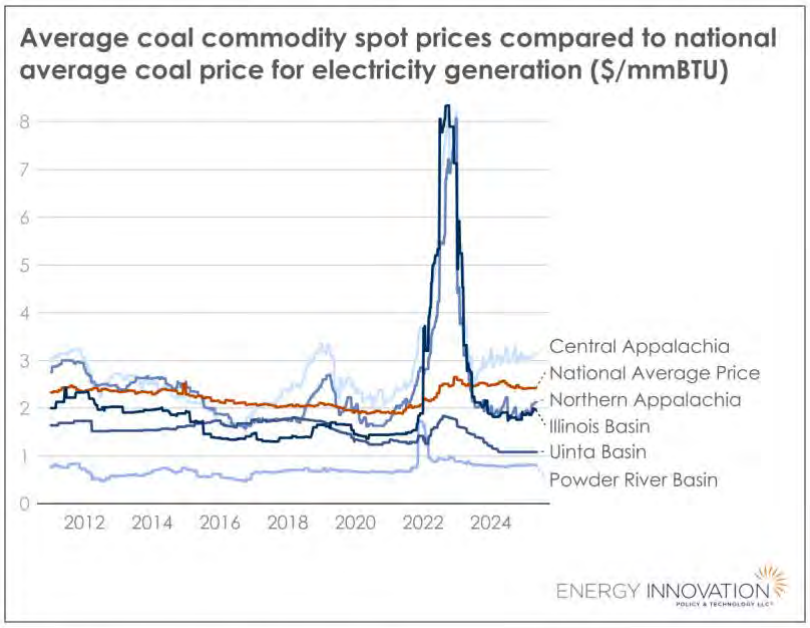
But these orders ignore the economic fundamentals underpinning coal's decline: wind, solar, batteries, natural gas, and efficiency are simply cheaper than coal power. Previous Energy Innovation research showed that 99 percent of coal plants were more expensive to continue operating compared to replacement with local wind or solar.[5] Attempts to keep coal running beyond plants' economic lifetime will force Americans to pay higher electricity bills.

As the new analysis detailed here shows, coal plants have only gotten more expensive since our last analysis based on the 2021 coal fleet, which largely followed the trends of the overall cost of coal for fuel.

Prices spiked in 2022, after Russia invaded Ukraine. This event increased all fossil fuel prices. While coal fuel prices fell after 2022, they remained elevated over 2021 levels in most regions of the country, and the national average price of coal delivered to the electricity sector remained elevated, too.

These higher prices are seen most acutely in the Appalachian coal producing regions, where coal has been more expensive for years due to the depth of coal within the mines, a problem that only becomes more acute with more mining.[6]

Our updated analysis uses the same methodology as detailed in the Coal Cost Crossover 3.0 for calculation of coal costs,[7] and shows coal's economic decline has continued.



Source: U.S. Energy Information Administration

[5] https://energyinnovation.org/report/the-coal-cost-crossover-3-0/
[6] https://www.eia.gov/energyexplained/coal/prices-and-outlook.php
[7] This methodology does not account for any increases in cost due to very large capital expenditures such as those required to comply with air pollutant regulations. Any pollution upgrades would significantly increase the costs of plants beyond what is calculated here.

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KEY FINDINGS

Power generated by coal in 2024 was 28 percent more expensive on average than in 2021

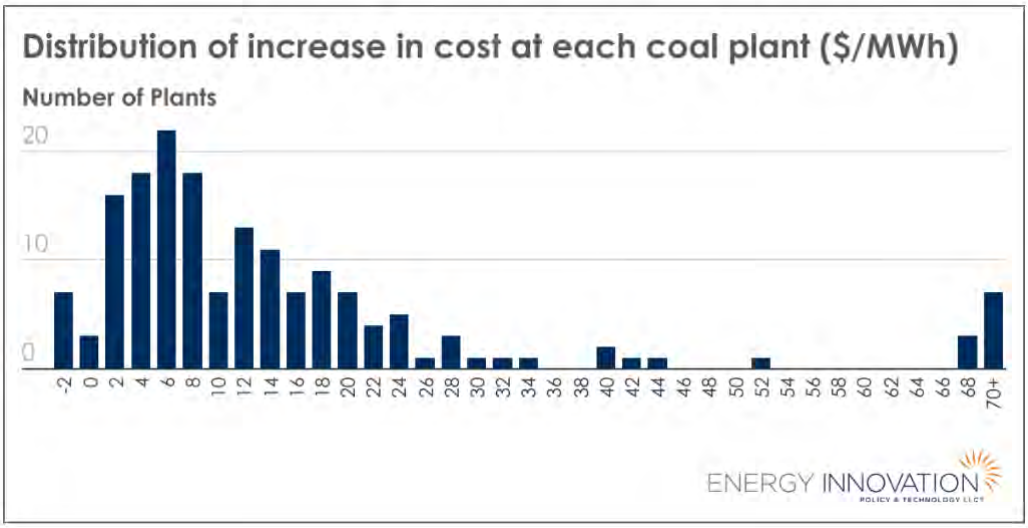
In 2021, the weighted average cost of a megawatt-hour (MWh) of power generated by coal-fired power plants was $36/MWh, while in 2024, this number rose to $46/MWh, or a 28 percent increase across the U.S. coal fleet. The Consumer Price Index, a proxy for inflation, increased by 16 percent from 2021 to 2024,[8] which means the cost of power generated by coal grew significantly faster than inflation.

Factors contributing to this increase include a rise in the cost of fuel for plants, as well as increased operations and maintenance costs and capital costs due to aging plants and inflation. Plants also ran less on average, which drives up their cost in dollars per MWh, with our analysis showing that the average coal plant capacity factors dropped to 38 percent in 2024 from 46 percent in 2021.

With 622 million megawatt hours of power generated by coal in 2024, this means coal plant owners spent over $6.2 billion more than they would have spent for that same amount of electricity generated by coal in 2021, costs that are directly passed onto consumers through electricity rates.

95 percent of remaining coal plants generated power at a higher cost than they did in 2021

We analyzed 162 plants, consisting of 181 GW of capacity, that were still operating at the beginning of 2025. Almost every plant saw costs increase but increases ranged widely between plants. 95 percent of plants were more expensive, and 76 percent of plants (142 GW) saw costs rise faster than inflation since 2021. Nearly half of these saw cost increases double the rate of inflation over this period.



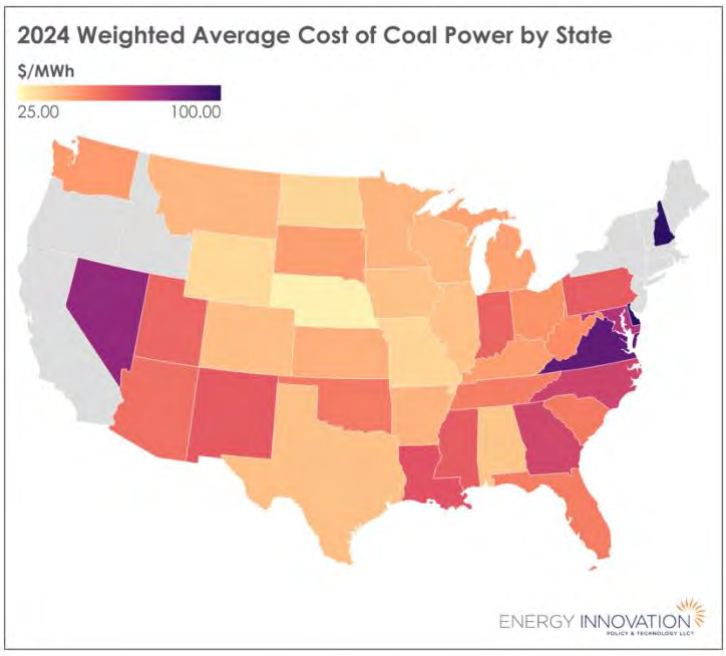
[8] https://www.minneapolisfed.org/about-us/monetary-policy/inflation-calculator/consumer-price-index-1913-

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The cost of coal was highest in the Mid-Atlantic, Southeast, and Southwest

Delaware and New Hampshire saw the highest coal costs on average in 2024. Each state has only one plant still in operation, and plans to shut these plants down are imminent, with Delaware's scheduled for retirement in 2026 and New Hampshire's in 2028. Outside of these two, the states with the highest coal cost were Georgia, Louisiana, Maryland, Mississippi, Nevada, New Mexico, North Carolina, and Virginia.

Many of the most expensive coal-burning states source coal from the most expensive mines, with states east of the Mississippi generally seeing more expensive average costs than those in the West.



Despite these high costs, states like Georgia and South Carolina have extended the lives of several plants, including Plant Bowen and Williams. Plant Bowen was originally scheduled for retirement in 2028, but Georgia Power has recently extended its life to 2035.[9] Its costs increased by $26/MWh, from $46/MWh to $72/MWh. Williams, a 659 MW plant in South Carolina has had its retirement pushed from 2028 to 2031 or even later in Dominion Energy's recent integrated resource plan. This delay comes even as this analysis shows the plant has increased in cost by $27/MWh, or over 50 percent.[10]

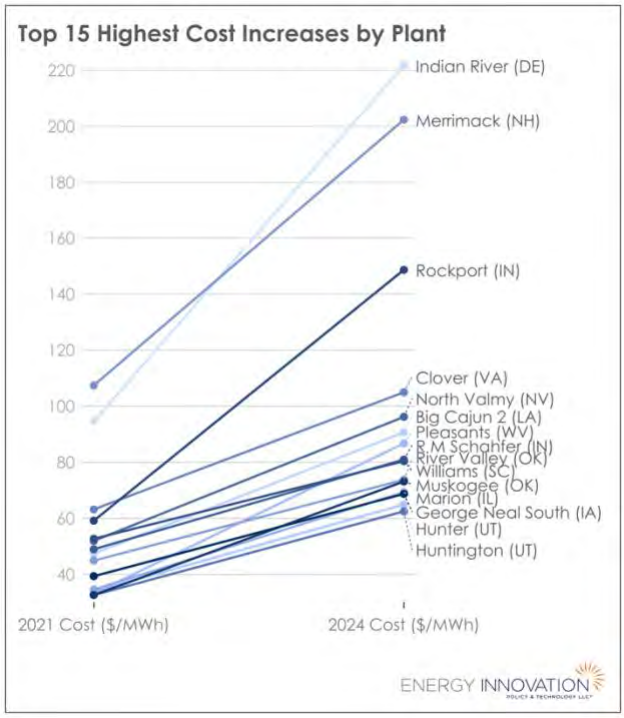
States in the West were not insulated from cost increases. Cost increases in Utah were particularly high, largely due to the Hunter and Huntington plants, which were previously scheduled for retirement in 2032, but instead are now planned to stay online indefinitely. The cost increase is largely due to issues with the mine that supplies coal to these plants, the Lila Coal Mine, which caught on fire in 2022, was declared "idled indefinitely" at the end of 2023 and all 150 workers laid off.[11] Costs to run these two plants nearly doubled from around $30/MWh to over $60/MWh. Even plants that have functioning dedicated mines in the cheapest coal region of the country, the Powder River Basin, have still seen significant increases in coal costs.

[9]https://georgiarecorder.com/briefs/two-georgia-power-coal-plants-among-the-dozens-now-exempt-from-biden-era-pollution-rule/
[10]https://www.wfyi.org/news/articles/duke-energy-plans-to-delay-gibson-coal-plant-retirement-activists-say-its-a-step-backward
[11]https://www.sierraclub.org/press-releases/2025/04/dominion-energy-keeps-south-carolina-s-coal-plants-operating-2025-irp-update#:~:text=Dominion%20has%20already%20pushed%20back,potentially%20as%20late%20as%202034.

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ACTIONS TO PROTECT CONSUMERS FROM RISING COSTS

Because the cost of coal power is increasing faster than inflation, the Trump administration's executive orders and attempts to keep coal-fired power plants running will increase the cost of electricity.



Coal-fired power increases its cost burden on customers year after year, and the period from 2021 to 2024 was no different. With costs increasing across America's entire fleet, states that continue to rely on coal, like Kentucky and West Virginia, have unsurprisingly suffered electric rates climbing faster than even those coal-heavy states that have begun to incorporate renewable power.[12] Even as this coal reliance has harmed electricity customers and neighboring states have declined cost recovery for upgrades, regulators in West Virginia have required plants to stay online. Meanwhile, residential electricity rates in West Virginia have risen 24 percent since 2021.

While keeping coal power online longer to meet growing load may seem like an attractive option, continuing to rely on these aging plants with high fuel costs will likely continue harming those captive customers whose policymakers force expensive plants to stay online, even as cheaper options are available. Strategies like moving new generation and battery storage through interconnection queues more quickly,[13] getting more out of the grid by upgrading transmission lines[14] and utilizing surplus interconnection capacity,[15] and deploying demand response and efficiency[16] can help ensure America has the capacity needed to meet growing load while protecting consumers from paying the price to subsidize uneconomic coal.

Comprehensive planning and competitive procurement are also essential to ensuring that electricity customers pay the cheapest price for power. Using best practices in integrated resource planning will make sure that least-cost resource portfolios are selected. These include inclusive stakeholder processes with technical experts participating, developing model inputs and cost estimates that align with real-world data and high quality forecasts, and analyzing multiple scenarios and sensitivities.[17]

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[12]https://kentuckylantern.com/2025/04/10/heavy-reliance-on-coal-has-eroded-a-ky-economic-advantage-can-trump-reverse-the-trend/
[13]https://collaborative.evergreenaction.com/memos/approving-clean-energy-projects-faster-could-save-consumers-505-a-year-in-these-13-states-16
[14] https://www.2035report.com/reconductoring/
[15] https://www.utilitydive.com/news/surplus-interconnection-gridlab-berkeley-report/740262/
[16] https://energyinnovation.org/wp-content/uploads/2024/03/MEETING-GROWING-ELECTRICITY-DEMAND-WITHOUT-GAS.pdf
[17] https://emp.lbl.gov/publications/best-practices-integrated-resource

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Beyond good planning, all-source competitive procurement, or the process by which all technologies are fairly considered to meet grid needs, can make sure that the cheapest plans turn into the cheapest projects built.[18]

Common-sense policies can also help reduce the impact of expensive coal plants on consumers. For instance, in many states, coal plants are permitted to run even when they are not the cheapest resource to meet the need. This is called "uneconomic dispatch," costs consumers over $2 billion annually, and is most prevalent in the Southeast and West where the lack of regional transmission operator reduces pricing transparency. Where full electricity markets are not implemented, moving towards day ahead or real time energy markets that are coordinated by a centralized entity is key to ensuring consumers pay a fair price, and utility regulators can push for better operational practices to save customers money.[19]

Electricity planners have options to keep the lights on, but electricity consumers generally have little to no choice in the price they pay for power. As costs continue to rise, now is not the time to double down on coal. It is up to the regulators and policymakers overseeing the coal fleet to protect consumers, and find cheaper, cleaner options to help Americans thrive.

[18]https://energyinnovation.org/report/making-the-most-of-the-power-plant-market-best-practices-for-all-source-procurement-of-electric-generation/
[19] https://rmi.org/how-utilities-can-save-customers-billions-of-dollars/

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-9

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

Exhibit 51

2023 Energy Innovation Coal Cost Report

Coal Cost Crossover 3.0: Local Renewables Plus Storage Create New Opportunities for Customer Savings and Community Reinvestment

MICHELLE SOLOMON, ERIC GIMON, MIKE O'BOYLE (ENERGY INNOVATION®), UMED PALIWAL, AND AMOL PHADKE (UNIVERSITY OF CALIFORNIA, BERKELEY)

JANUARY 2023

EXECUTIVE SUMMARY

The cost of operating existing coal power plants in the United States continues to increase while coal jobs, generation, and mining all decrease.[i] New coal retirement announcements seem to happen faster, even as natural gas prices skyrocket, and renewable energy prices keep dropping.

The Inflation Reduction Act (IRA), which extended and expanded clean energy tax credits, along with new funding to guarantee loans for refinancing fossil assets and reinvesting in clean energy infrastructure, has shifted the economic scale even further toward wind and solar. But it also creates thoughtful new investment opportunities in areas burdened by existing coal plants with a 10 percent tax credit boost for projects located in nearby communities.

These factors underpin the third iteration of our Coal Cost Crossover analysis, which shows wind and solar energy are unequivocally cheaper than coal-fired generation across the country. This study finds 99 percent of all coal-fired power plants in the U.S. are more expensive to operate on a forward-

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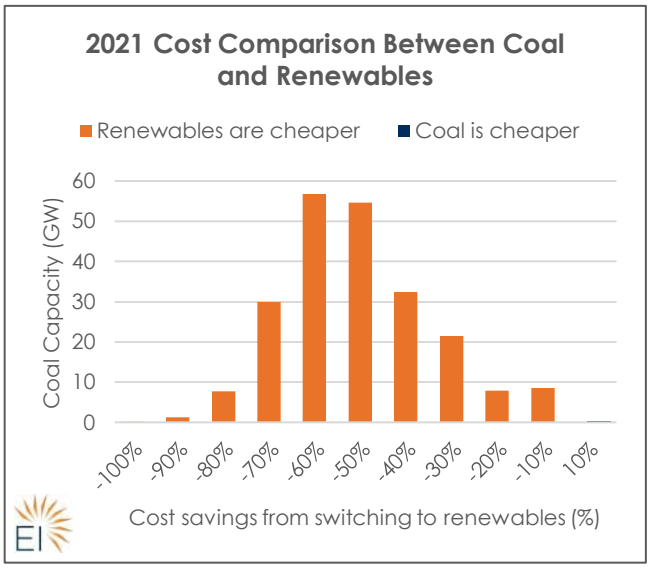
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looking basis than the all-in cost of replacement renewable energy projects, and 97 percent are more expensive than renewable energy projects sited within 45 kilometers (approximately 30 miles), a significant acceleration from our two previous analyses. For more than three quarters of U.S. coal capacity, the all-in cost per MWh of the cheapest renewable option is at least a third cheaper than the going-forward costs for the coal it would replace.

In this report we compare the cost of operating each continental U.S. coal plant in 2021, totaling 220 gigawatts (GW) of coal capacity across the country, to the estimated costs of building new wind and solar generation. We consider the wind and solar costs within two geographic scopes: local to the coal plants (within 45 kilometers) and regionally (roughly within the utility balancing area), finding that nearly all existing coal plants have multiple lower-cost clean energy replacement options.



This research shows all but one of the country's 210 coal plants are more expensive to operate than either new wind or new solar. If the IRA's new energy community tax credit is included in the equation, 199 of the 210 plants are more expensive to operate compared to local solar resources sited within 45 kilometers of the plant. Local wind resources are also cost-effective and readily available, with 104 plants having cheaper wind resources within 45 kilometers.

Altogether, 205 plants have local renewable options that would be cheaper than coal-fired electricity. This potential to replace existing coal plants with cheap, local clean energy generation creates significant economic benefits for community transition. Our analysis finds replacing these plants with local solar or wind would drive $589 billion in local capital investment that could support economic diversification, job creation, and tax revenue.

These local wind and solar resources could also help solve the problem of long interconnection queues—a significant barrier to renewables deployment. Renewable projects built near a retiring coal plant could use the existing plant's interconnection, helping to further lower costs. If more policymakers consider this dynamic, they can streamline economic replacement and anticipate coal retirements, which are accelerating due to the cost dynamics analyzed in this report.

While solar and wind replacement resources provide significant low-cost energy and reliability value to the grid, savings generated by switching from more expensive coal to cheaper clean energy can finance other resources to provide additional energy and reliability value.

We find that the savings generated by shifting to local solar could fund the addition of 137 GW of four-hour batteries across all plants, and 80 percent or more of the capacity at a third of existing coal plants – the economics of replacing coal with renewables are so favorable that they could fund a massive battery storage buildout to add reliability value along with emissions reductions. However, it is important to remember reliability is a system attribute—replacement renewable

portfolios need not bear sole responsibility for replacing the reliability services of individual coal plants.

While the economic case is clear and virtually universal, barriers remain to replacing coal with clean energy, and policymakers must act to unlock the cost savings and human health benefits for coal communities while reducing climate pollution.

Several policies can enable a faster coal-to-clean transition. Specifically:

- To prepare the way for coal transition, regulators and system operators should:
  - Improve methods to assess reliability and resource adequacy reflecting the reliability value of renewable portfolios and valuing the reliability attributes of a high-renewables grid.
  - Update interconnection study rules to leveraging existing coal plant interconnection rights to speed grid connection processes for local renewable replacement resources.
- To proactively pursue the transition, regulators should:
  - Encourage utilities to utilize IRA financing programs available through the Departments of Energy and Agriculture to remove financial barriers to coal community economic transition and investment.
  - Enable competitive resource procurement.
  - Require re-assessment of any utility investment plan, including integrated resource plans and market-based solicitations for renewable supply, completed prior to IRA as renewables costs are now out of date.
- To create a just transition for affected communities, state legislatures and energy offices should:
  - Plan for and fund a coal community-centered economic transition, where local clean energy resources are the anchor for a more expansive economic transition plan.

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INTRODUCTION

The U.S. power sector is in transition, with coal-fired power generation falling to 55 percent of its 2007 peak in 2021. This transition is also decreasing the number of coal mines, power plants, and workers. Over the same period, utility-scale solar and wind generation have increased more than

18,000 percent and 1,000 percent, respectively, as costs declined by 90 percent for solar and 72 percent for wind.[1,ii]

In 2019, Energy Innovation Policy & Technology LLC® partnered with Vibrant Clean Energy to compile and analyze a 2018 dataset of capital, operations and maintenance, and fuel costs for coal, wind, and solar. Our first Coal Cost Crossover report found that 62 percent of existing coal capacity was uneconomic compared to producing the same amount of energy with new local wind or solar. To make this comparison, we evaluated the marginal cost of running each coal plant with the levelized cost of new wind and solar, where the levelized cost of energy (LCOE) is the cost of building and operating a new resource divided by its energy production over its lifetime. The analysis projected that by 2025, more than 80 percent of the coal fleet would be unable to compete against new renewables or would be retired, even without federal incentives.[2]

In 2021, we completed a similar analysis of 2019 data that considered the National Renewable Energy Laboratory's (NREL) 2018 Annual Technology Baseline (ATB) forecast showing steep cost declines for solar and wind energy, as well as an extension of the federal investment tax credit for solar coupled with a continued production tax credit for wind. The Coal Cost Crossover 2.0 report found that the coal crossover had significantly expanded, with 72 percent of coal capacity and 80 percent of plants already more expensive to run compared to either new solar or wind, including tax credits in effect.[3]

This Coal Cost Crossover 3.0 report uses new 2021 data to reevaluate the coal crossover economic dynamic. Since our 2.0 report, solar and wind costs continued fall, coal prices kept rising, and coal plant capacity factors continued decreasing, all continuing the trends observed between 2017-2019.[iii]

Now, new federal tax credits in the IRA make the economic case for replacing coal with clean energy unequivocal. IRA incentive bonuses for clean energy projects located near retired coal infrastructure offer new, additional savings and reinvestment opportunities. This report combines elements of the previous two studies, analyzing both regional and local renewable resources, but now accounts for the new incentives.[4] Given the IRA's expanded tax credits, we find all coal plants but one are more costly to run compared to new wind and solar energy, and all but five are more expensive than wind or solar sited within a 45 kilometer (km) radius.

Of course, examining relative economics using levelized cost faces limitations. The overall value of these power plants depends on much more than just cost. While the coal cost crossover describes a scenario in which renewable resources replace coal generation on a one-to-one basis, the reality is that coal retirement is a complex process that depends on the reliability needs of the local and

[ii] Coal generation decreased from 2,016,455 gigawatt-hours (GWh) in 2007 to 875,885 GWh in 2021. Solar generation increased from only 612 GWh in 2007 to 115,258 GWh in 2021. Wind generation increased from 34,449 GWh in 2007 to 378,196 GWh in 2021. In total, coal generation was still higher in 2021 than wind and solar in the U.S. by 382 GWh.
[iii] Renewable costs continued to fall through 2021, the year we used for this analysis. Costs across the energy industry rose in 2022 due to supply chain constraints but are expected to fall again as supply issues ease.

regional electricity grid, which in turn, depends on the entire resource portfolio's dynamics. For example, in some regions one-to-one replacement with a combination of wind and solar resources may not adversely affect reliability. In others it may, depending on what other resources are serving the power grid.

Many communities also depend on coal plants for jobs and tax revenue. In addition to reliability value, policymakers must consider the potential of replacement energy resources to provide similar economic value. The new IRA incentives to locate replacement resources in the same communities where coal plants sit can contribute to a sustainable, economic transition. As we show in this report, these incentives fundamentally improve the prospect for coal communities to benefit from new clean energy resource development.

This report traces the shifting role of coal in the U.S. power sector and identifies key changes in the economics of coal-fired electricity generation due to the IRA's passage. We explain our coal cost crossover calculations, including how we compiled the coal dataset using publicly available data, and how we calculated the LCOE for both local and regional wind and solar using open-source modeling tools developed by NREL.

Four scenarios compare new renewable generation costs to marginal coal costs: regional wind, regional solar, local wind, and local solar, effectively assessing the replacement of every unit of energy produced by the coal plants. For the local solar scenario, we also analyze the economics of adding four hours of battery storage capacity to the solar resources. This analysis demonstrates a clean alternative to coal generation with added reliability value and an opportunity for local investment and economic diversification.

Finally, we provide policy recommendations to help policymakers successfully transition away from polluting, higher cost coal power to cheaper, clean energy. Because the IRA aligns the aims of least-cost electricity planning and procurement with an economic transition for coal communities, we highlight the opportunity for gradual economic transition centered around replacing coal generation with local renewables and storage. Local replacement also has the advantage of potentially being able to leverage existing grid interconnection rights. We describe how utilities can directly take advantage of key IRA provisions, as well as how policymakers can ensure utilities account for the changing economic landscape in their planning and procurement. We also explain how just transition planning, accurate reliability assessments, and transmission buildout can speed up and smooth out coal's phaseout in the U.S.

COAL'S ROLE IN THE U.S. POWER SECTOR

Coal-fired power was the bedrock of a reliable, affordable U.S. power sector for nearly a century. But since 2010, coal generation has declined 52 percent, and renewable power generation exceeded coal generation for the first time in 2020. In 2011, the U.S. had 317.6 GW of coal-fired

electricity generation capacity,[5] but that number fell to 221 GW in 2021. Nearly a quarter of the remaining fleet is slated for retirement by 2029.[6]

Several factors explain this decline, including pollution control standards requiring costly retrofits, cheap natural gas and renewable power, state clean energy policies, and improved building and industrial efficiency.[7] Coal's decline has been accompanied by a precipitous fall in coal industry employment.[8] But even as employment fell, reduced pollution from coal plants dramatically improved public health. Annual deaths attributed to air pollution from coal plants fell from 30,000 deaths in 2000 to less than 3,000 in 2019.[9]

Coal's role in electricity system reliability has shrunk considerably. Coal-fired power plants operate as part of an integrated power system where supply and demand must remain in constant balance. The decline in coal-fired generation and capacity, and replacement by a more diverse portfolio of gas and renewable power plants with vastly different operational characteristics indicates that coal is not necessary for reliable power systems. For example, the United Kingdom reliably operated its grid without any coal generation for two straight months in 2020.[10]

The role of coal plants and their operation in the electricity system has also changed over time. Historically, coal plants operated as "baseload" power plants, relying on a relatively low-cost fuel supply to run at a constant, high output. But now markets are pushing coal plants to operate more variably, ramping up and down as the economics and availability of renewable energy fluctuate throughout the day and over a season.[11] Coal plants in our dataset had an average capacity factor of 46 percent, which means they ran, on average, only 46 percent of the time. This on-again, off-again operation increases wear and tear on coal plants designed for a different operating paradigm.

Displacement by cheaper gas and renewables means baseload operation is increasingly unprofitable for existing coal—operating at high output when plentiful clean energy resources operate at zero marginal cost is a waste of fuel. According to RMI, since 2012 utilities could have saved customers $1–$2 billion per year by turning down coal and relying on lower-cost, less polluting resources. This is partially due to self-scheduling, a practice through which monopoly utilities uneconomically run their coal plants in wholesale markets and charge captive customers the difference.[12]

Replacing coal with clean energy is not a one-to-one exercise. System operators and utilities only gain confidence that coal retirements won't adversely affect system reliability by evaluating the reliability of the entire energy portfolio. A recent North American Electric Reliability Corporation (NERC) assessment highlighted the need to build new generation before retiring old generation when reliability risks are present.[13] But recent studies such as the 2030 Report, which found an 80 percent clean, coal-free electricity system to be both reliable and affordable, confirm we can maintain a dependable electricity system without coal.[14]

The U.S. will continue relying on coal plants for reliability until we add enough new clean resources (including demand-side resources and transmission) to replace their reliability and energy services.

The Coal Cost Crossover 3.0 analysis highlights opportunities to economically displace coal-fired generation and replace those services in part. With the IRA's passage, the economic case for shifting from coal to renewables is stronger than ever.

INFLATION REDUCTION ACT IMPACTS ON U.S. ENERGY ECONOMICS

The IRA will significantly affect the relative economics of coal and clean power in the U.S. In this analysis, the IRA's extended and improved tax credits, along with a pair of refinancing programs, have the greatest effect on the cost of coal compared to renewables.

Tax Credits

Clean energy tax credits have arguably been the most important federal climate policies to date, driving nationwide solar and wind growth. The IRA builds upon this successful policy to make the clean energy transition cost effective for the long term, with earlier Energy Innovation® analysis finding the credits to be the most impactful IRA provision for electricity sector decarbonization.[15]

The production tax credit (PTC) and investment tax credit (ITC) are the IRA's two key tax credits for new clean electricity resources. Historically, the PTC has primarily supported wind energy resources, and at its full value paid approximately $26 per megawatt-hour (MWh) in 2022 dollars over the first 10 years of a wind project's commercial operations.[16] The ITC has largely supported solar resources, and at its full value offered a tax credit for 30 percent of total system cost, paid out when it is first placed in service. Prior to the IRA's passage, the PTC had expired, and the ITC had begun phasing out with a value of 26 percent for projects starting construction in 2022.[17] The IRA created long-term certainty for these tax credits, with the extension lasting through 2032 or until electricity sector greenhouse gas (GHG) emissions fall 75 percent below 2022 levels, whichever is later.

The IRA also immediately revived a long-expired option for solar projects placed in service in 2022 or later to elect the PTC instead of the ITC, which ensures that tax credits will stay impactful as solar capital costs continue to fall. In addition, the IRA provides an ITC for stand-alone energy storage technologies placed in service in 2022 or later, removing prior restrictions that required storage to be co-located with and charged primarily from solar energy resources.

Beyond the extension and increased flexibility, the IRA created several human impact bonuses that increase the value of the tax credit. To qualify for the full credit, a project must meet prevailing wage and apprenticeship requirements. Additionally, a project can earn a 10 percent boost for meeting domestic content requirements and an additional 10 percent for locating the project in an energy community (which includes census tracts in which coal-fired power plants have been retired since 2009 and adjacent census tracts, as defined by the IRA, see Figure 1).[iv]

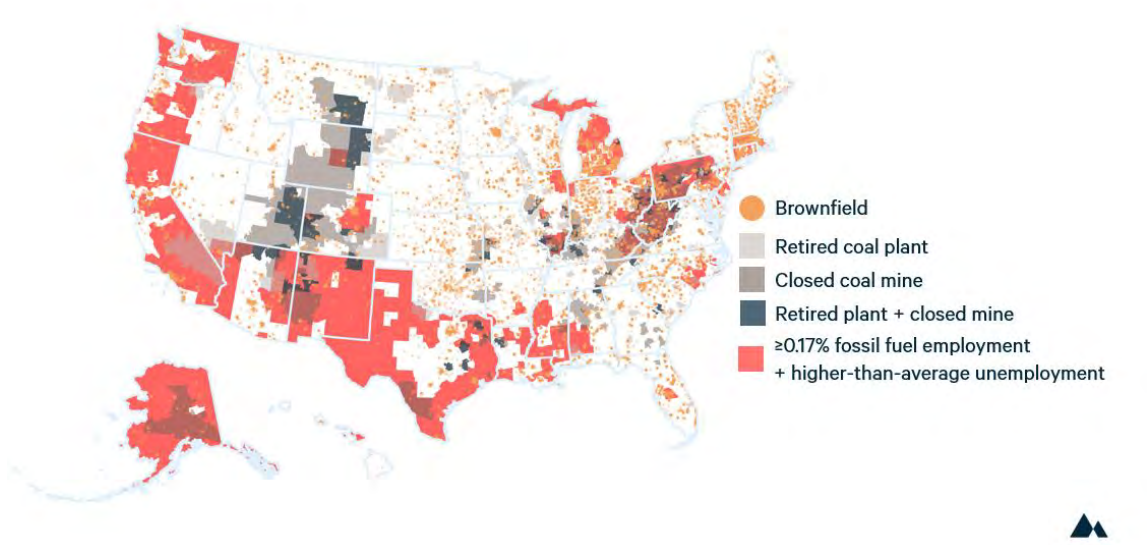


Figure 1. Map of probable energy communities, as defined by the IRA. Source: Resources for the Future.[18]

The combined impacts of energy community, labor, and domestic content bonuses reshape solar economics in coal communities. The median cost of new solar in these communities is about $24/MWh with low variance, while the median marginal cost of coal is $36/MWh with higher variance (see Figure 2). As discussed later in this report, this cost differential provides significant headroom for additional battery storage, which can also qualify for energy community bonuses.

[iv] The 10 percent credit boost for siting projects in energy communities works slightly differently for the ITC and PTC, providing a 10-percentage point ITC bonus and a 10 percent bonus on the PTC credit value.

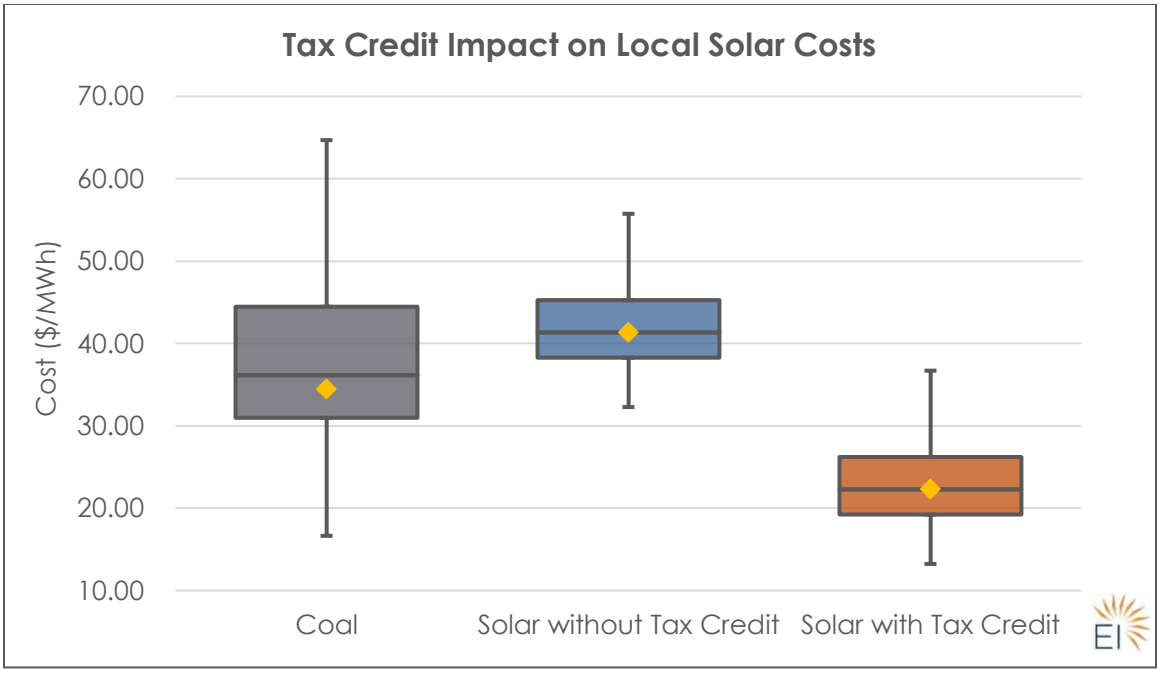


Figure 2. Impact of tax credits on local solar LCOEs in our analysis, including the energy community bonus. The yellow diamond indicates the average cost of each resource (weighted by generation). With the IRA, the economic case for local solar becomes unequivocal.

Revinvestment Financing

The PTC and ITC play the crucial role of decreasing the cost of developing clean electricity resources, but upfront cost is far from the only barrier to moving from coal generation to clean alternatives. One of the biggest hurdles to this transition is the rate impacts of adding large capital investments to utility rates when billions are still owed to debtors and investors on uneconomic coal assets. But a new IRA financing program to invest in clean energy infrastructure in current or former coal communities can overcome this hurdle. As the program only lasts until 2026, time is of the essence.

Most U.S. coal capacity is owned and operated by monopoly utilities, which collectively hold at least $176 billion in unpaid fossil plant balances[v]—accounting ledgers that represent the debt and equity capital structures utilities used to finance these plants over time. Utilities include this capital cost in electricity rates, typically recovered over the plant's entire lifetime in a financial arrangement somewhat similar to a conventional 30-year mortgage (albeit one that is continuously extended as new capital is invested at coal plants). As long as the plant remains in operation or

until the investment is fully depreciated, customers are generally obligated to continue to cover these costs, which include substantial returns for utility shareholders. Without a change to this structure, monopoly utilities have little to gain from early coal plant retirement and they may perceive retirement or partial replacement as putting cost recovery at risk.

New IRA programs provide flexible, low-cost financing to clean up utility balance sheets by reducing the cost of investing in new local clean energy infrastructure, including wind, solar, batteries, transmission infrastructure, and reuse of the coal plant itself. Utilities and other power plant operators, such as independent power producers, can access low-cost government-backed loans to reduce the rate impacts associated with large capital expenditures required to transition from coal to clean and stimulate local economic development. The IRA created two novel programs to support utilities in transition:

First, the IRA appropriated $5 billion to the U.S. Department of Energy's (DOE) Loan Programs Office (LPO) via the Energy Infrastructure Reinvestment (EIR) program to support $250 billion in loan-making authority to facilitate refinancing and reinvestment in capital projects at fossil infrastructure sites, using below-market interest rates. Funds can be used flexibly to "re-tool, re-power, re-purpose, or replace" fossil infrastructure across the entire energy industry (including non-utilities), reducing the cost of replacement resources and creating numerous pathways for community diversification and redevelopment. The financing provisions are flexible enough to work for all parties—utilities, consumers, and communities. These stakeholders can use the financing to reduce the near-term rate impacts of capital transition, allowing new investment to arrive sooner in these communities that sorely need it as aging fossil plants ramp down.

Second, the IRA authorized a $9.7 billion program specifically for rural electric cooperatives through the U.S. Department of Agriculture (USDA). Rural electric cooperatives provide electricity to more than 40 million people. Their power supply is particularly coal-heavy, with coal accounting for 28 percent of generation in 2020 compared to 19 percent nationwide.[19] This means surrounding rural communities bear a disproportionate burden of coal-related pollution, while member-owned cooperative customers remain tethered to coal debt. While members may want to transition to clean energy to capture pollution and cost savings, this debt holds them back. Furthermore, simply shutting down cooperative coal plants could impact communities that rely on relatively high-paying jobs where economic opportunities are sparse. To address these challenges, the IRA funds USDA to provide direct grants or loans for rural electric cooperatives to procure clean energy, with an express purpose of reducing GHG emissions.

METHODOLOGY

As in the previous two coal cost crossover studies, this report compares the marginal cost of energy (MCOE) for existing coal plants across the U.S. with the LCOE for solar and wind. We compare the same coal costs to four different cost scenarios for renewables. Scenarios vary by resource type

(wind or solar) and by geographic scope (regional or local). For the first two scenarios, regional solar and regional wind, we separately examine the costs of solar and wind located within the same region as a given coal plant, calculating the LCOE to replace each plant's annual generation within a nearby region that corresponds roughly to the utility's service territory.[vi]

For the last two scenarios, local solar and local wind, we look at local costs for solar and wind separately, calculating the cost if all replacement renewables are sited within a 45 km radius of the existing coal plant. Local solar and wind projects get the additional energy community tax credit bonuses in the IRA, which helps to offset losses in power resource quality due to the local siting constraint. A more detailed explanation of our methodology is available in this report's Appendix.

Coal Economics

To calculate the MCOE at each coal plant, we sum three cost components: the cost of fuel, the fixed and variable costs of operations and maintenance, and the going-forward routine capital expenditure costs, each calculated on a per-MWh basis. Using 2021 U.S. Energy Information Administration (EIA) data, we calculate the total going-forward marginal cost for all coal plants operated by utilities or independent power producers in the continental U.S., excluding plants that are used for co-generation of heat. These costs appropriately comprise marginal cost because they would not be paid if the coal plant retired. By contrast, we do not include unpaid capital balances as part of the MCOE because their payment does not depend on whether the plant retires.[vii]

Renewable Economics

We used NREL's Regional Energy Deployment System (ReEDS) model to calculate solar and wind LCOE values, which are all-in estimates of the cost of energy output in MWh, taking into account all capital expenditure, operations, and maintenance costs. We used the 2021 actual cost values from the 2022 NREL ATB.

The ReEDS model uses solar and wind resource potential values at around 50,000 sites across the country, accounting for comprehensive exclusion criteria, including land cover, elevation, slope, environmentally sensitive areas, and local siting regulations. The model also provides annual capacity factors at each of these sites. The site-specific LCOE is then calculated based on capacity factor, as well as a comprehensive list of parameters including capital costs, fixed operation and maintenance costs, equity costs, interest rates, construction costs by location, construction period,

[vi] We use regions defined by NREL's Regional Energy Deployment System model, explained in detail in the appendix.
[vii] These remaining balances are the primary target of the reinvestment programs created by the IRA. Though we don't include the balances in our cost calculations, the potential to refinance and replace with clean energy is another path toward reducing coal generation beyond operating costs.

IRA tax credits, and depreciation. We calculate the LCOE after accounting for both the ITC and PTC 2022 tax credit values, using the cheaper of the two.

Renewables key assumptions

Across the four renewable scenarios, we make several key assumptions:

- Regional solar and wind costs include new grid interconnection costs, while local resources do not.
- All renewable resources qualify for the prevailing wage and apprenticeship hour tax credit bonus.
- All wind resources qualify for the full domestic content bonus, while 42 percent of solar resources qualify for the domestic content tax credit bonus based on current domestic content levels.[20]
- Storage does not qualify for the domestic content credit bonus.
- All tax credits are reduced by 10 percent to account for transfer losses.

Regional renewables scenarios

For the two regional renewable cost scenarios, regional wind and regional solar, we start by finding the LCOE for regional wind and solar that could replace each plant's 2021 annual generation. The region we study for each plant is based on the ReEDS balancing area (of which there are 134, see Appendix) in which the plant is located, corresponding roughly to the utility territory. For each coal plant, we sort the wind and solar sites available in that region by LCOE and choose the best sites based on capacity factor to replace the coal generation. For selected sites within each region, we capacity-weight the site-level LCOEs to estimate the weighted average regional LCOE. Interconnection costs associated with transmission lines that connect the project to the grid are also added into these LCOEs, while we make no assumption about broader grid impacts.

Local renewables scenarios

For the local wind and local solar scenarios, we first determine the viability of the local wind or solar replacements for each coal plant. Using the plant's latitude and longitude as the center, we create concentric circles around each coal plant, starting with a radius of 5 km and moving up to 45 km in 5 km increments. We identify the solar and wind sites that fall within each of these concentric circles and separately estimate the site-level capacity and annual generation potential for solar and wind resources. We then estimate the minimum radius needed to replace the annual generation from each coal power plant with solar or wind resources.

If there is enough generation found within the 45 km radius, we then determine the local LCOE by capacity-weighting the site-level LCOEs for the maximum radius needed to match the existing

plant's generation. For solar, nearly all plants meet the generation requirement within a 20 km radius while for wind, the average radius is much larger and there are many plants without enough wind generation within 45 km because of the more site-specific nature of wind energy potential and the larger land footprint (see Figure 3).

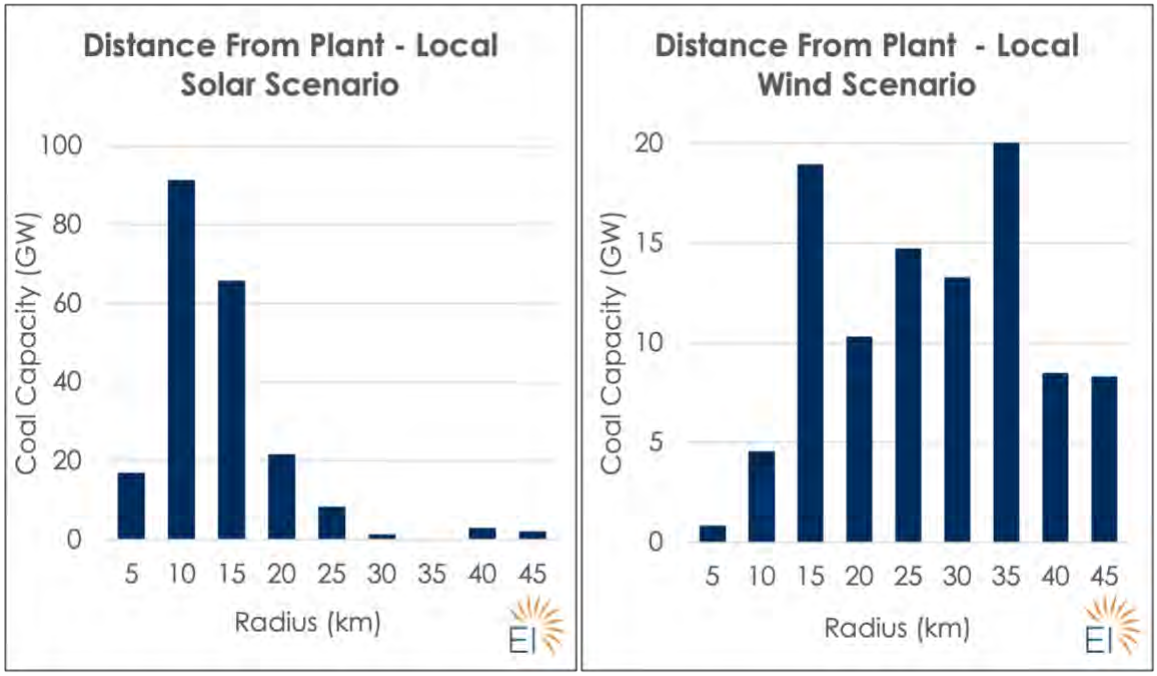


Figure 3. This figure plots the radius needed to match each plant's generation, while still being cheaper than coal, for both local solar and local wind. The majority of coal capacity has enough solar potential within a 20 km radius to meet the plant's entire annual generation in our local analysis and still provide cheaper energy than coal. While many plants have sufficient and cost-effective local wind nearby, less potential is available in close proximity for local wind.

For the local scenarios, we assume that all projects sited within 45 km of the plant will receive the IRA's 10 percent energy community bonus tax credit, given that both the census tract and neighboring census tract to any retiring coal plant fit the IRA's definition of an energy community. For these scenarios, interconnection costs are not included in the LCOEs as we assume that the new resources can utilize the existing plant's interconnection infrastructure.

Storage analysis

For the local solar scenario, we also analyze the economic feasibility of installing four-hour battery storage capacity along with the solar to provide additional reliability services to the grid. For this analysis, we start with a $330 per kilowatt-hour (kWh) price for the storage,[viii] and we include a 36

[viii] This price is based on the 2021 actual storage costs in the NREL 2022 ATB.

percent ITC (the full credit plus the energy community bonus, minus transferability losses). After calculating the savings from replacing the coal generation with local solar generation, we then determine how much battery capacity those cost savings would fund. Due to uncertainty in the battery price going forward, we calculate the battery capacity funded for storage prices ranging from $100 to $400/kWh.

RESULTS & DISCUSSION

Main findings:

1. >99 percent of plants studied are more expensive to run than to replace with new renewable wind or solar energy.
2. >97 percent of plants studied are more expensive to run than to replace with either local solar or local wind energy within 45 km (approximately 30 miles) of the coal plant.
3. Replacing coal generation with local solar resources could drive up to $589 billion in clean energy investment in energy communities across the U.S.
4. Replacing coal generation with local renewable resources could save enough to finance installation of 137 GW of four-hour battery storage—62 percent of the coal fleet's nameplate capacity.

Overall comparison between coal and renewable costs

For this report we combined elements of the two previous Coal Cost Crossover reports: We looked at replacing coal power with regional wind or solar resources *and* at replacing coal power with local wind or solar resources close enough to a plant to take advantage of its transmission connection and the energy community bonus tax credit. Across these four scenarios, we found that:

- 199 plants are more expensive to run than to replace with regional wind.
- 190 plants are more expensive to run than to replace than regional solar.
- 104 plants are more expensive to run than to replace than local wind.
- 199 plants are more expensive to run than to replace than local solar.

Analyzing these scenarios together, we found all but a single coal plant[ix] in the dataset of U.S. coal plants to be more expensive (lower renewable LCOE than coal MCOE) compared to replacement by at least one of these renewable options. Between local solar and local wind, 205 out of 210 plants had at least one cost-effective local renewable option. Of these, 98 had *both* local solar and local wind options that were cheaper than coal (see Figure 4). This represents a sharp acceleration

[ix] The single coal plant is the Dry Forks Station in Wyoming. It is the newest and among the cleanest coal plants in the U.S. coal fleet and is still only $0.32/MWh cheaper to operate than available regional wind. It is also a testbed for carbon capture use and storage (see https://www.powermag.com/dry-fork-a-model-of-modern-u-s-coal-power/). A similar plant built today would include capital costs and would not be competitive with new renewables.

in the previously observed trend in our coal cost crossover reports (see Figure 5). The full results of all four scenarios can be viewed in the accompanying spreadsheet.

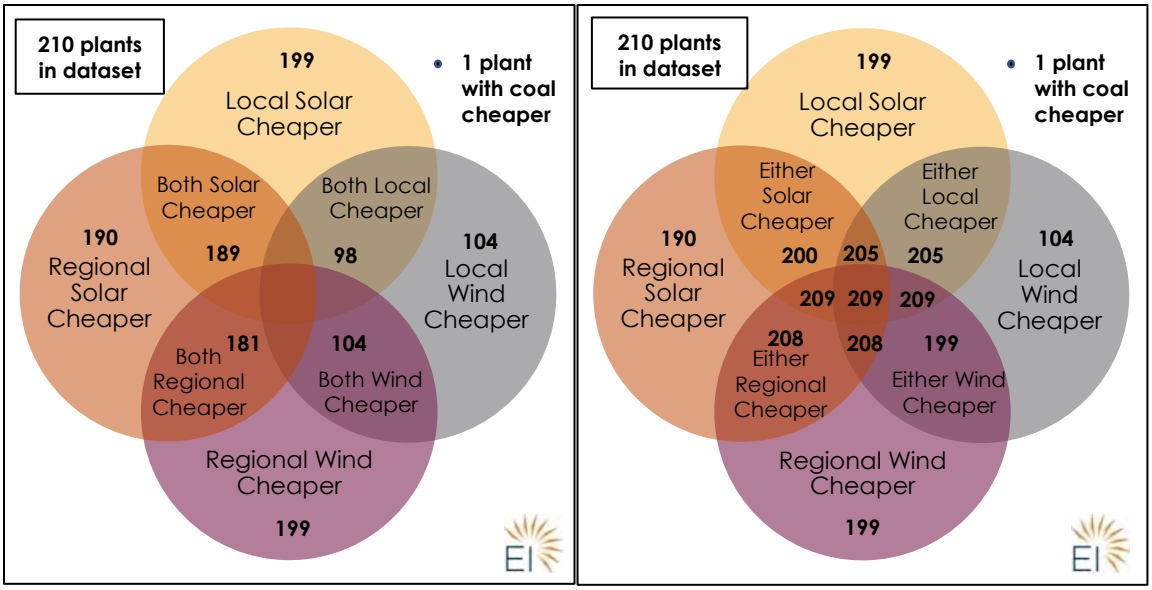


Figure 4. A closer look at the 210 coal plants in our data set based on the specific comparison with renewables that was made. The Venn diagram on the right looks at inclusive intersections (either resource is cheaper than coal) while the one on the left looks at exclusive intersections (both resources are cheaper than coal). We did not analyze any hybrid combinations of wind and solar, although this is clearly a possibility in the local context (98 plants) and the regional context (181 plants).

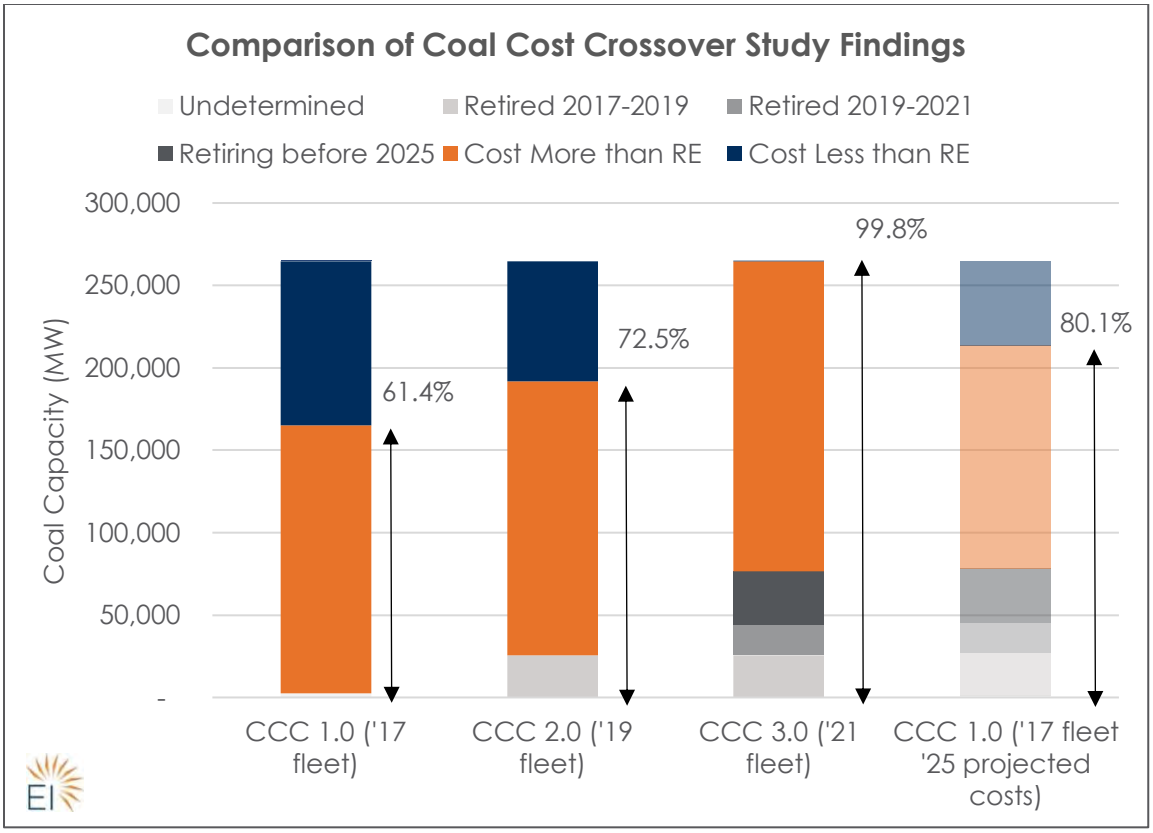


Figure 5. Comparison of our two original analyses of renewables and coal cost-competitiveness. The first included a 2025 projection for renewable costs to compare with 2017 coal going-forward costs. This comparison highlights how much the trend for coal being uneconomic compared to replacement by renewables has accelerated since the first report published in 2019.

Comparison between coal and cheapest available wind or solar resource

For the plants that were uneconomic, multiple renewable options were less expensive than coal generation, but regional wind and local solar were most frequently the cheapest overall resources (see Figure 6 and Figure 7). Regional wind was the cheapest option for 117 plants, while the most economic resource was local solar for 75 plants, local wind for 13, and regional solar for only four.

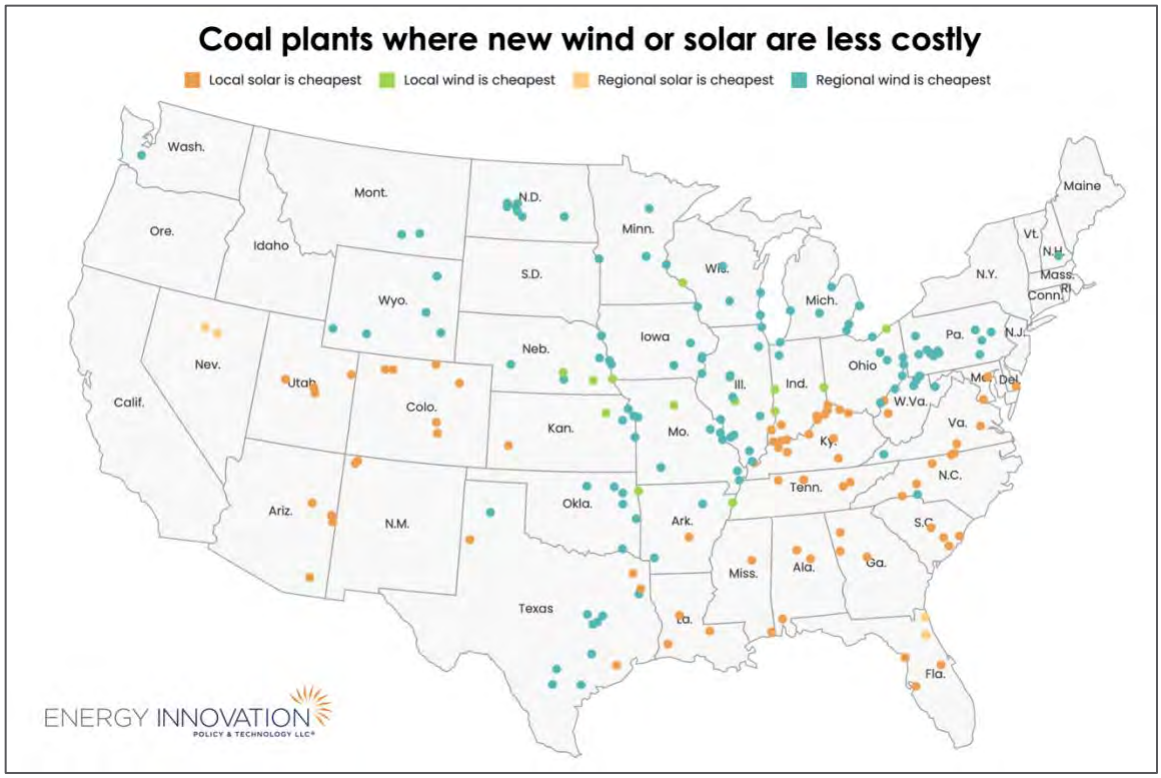


Figure 6. While most plants have multiple cheaper renewable options, the overall cheapest renewable resource varies by geography.

Notably, for solar, local replacement is cheaper than regional replacement in many cases due to low regional cost variability, lower transmission spur line costs,[x] and IRA energy community bonuses. For regional versus local wind, however, regional resources tend to be cheaper even with the added costs due to higher variation in resource quality for wind—going further from the plant often yields significantly better wind energy sites.

[x] A "spur line" is the transmission line that connects a renewable project to the bulk system at a point of interconnection. In this analysis, we do not make assumptions about interconnection costs beyond the cost of building the spur line. In this limited respect, we anticipate that local wind and solar costs would be lower than regional renewables, because local renewables are adjacent to the coal plant's point of interconnection. We recognize that interconnection costs for renewables have been increasing for a variety of reasons as they sit in ever-growing interconnection queues around the country, but also hypothesize that some renewables could reuse existing coal plant interconnection rights with very low interconnection costs. See https://emp.lbl.gov/news/pjm-data-show-substantial-increases.

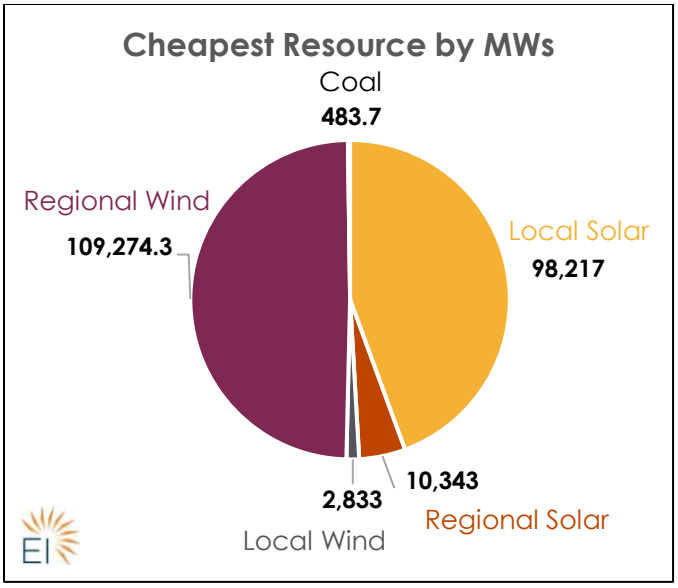


Figure 7. This chart shows the cheapest renewable resource option for each MW of coal capacity studied in this report. Local solar and regional wind are the cheapest renewable resources for nearly all plants.

We still see a wide range in the relative economics between existing coal and new wind or solar, with the all-in costs for the cheapest renewable option anywhere from zero (for one plant) up to 80 percent cheaper than the going-forward costs for coal, absent a few edge cases. Typically, the least economic plants have low capacity factors that result in very high fixed marginal costs per MWh or very high fuel costs.

For more than three-quarters of U.S. coal capacity, the all-in cost per MWh of the cheapest renewable option is at least a third cheaper than the going-forward costs for the coal it would replace (see Figure 8).

The substantial cost savings from replacing coal with renewables indicates the potential to invest in additional resources that provide complementary services like flexibility and transmission, without raising costs. Policymakers should consider a portfolio of clean resources that together provides adequate value and any needed reliability services. These resources could include storage,

regional or interregional transmission upgrades, demand-side resources, and complementary portfolios of wind and solar.

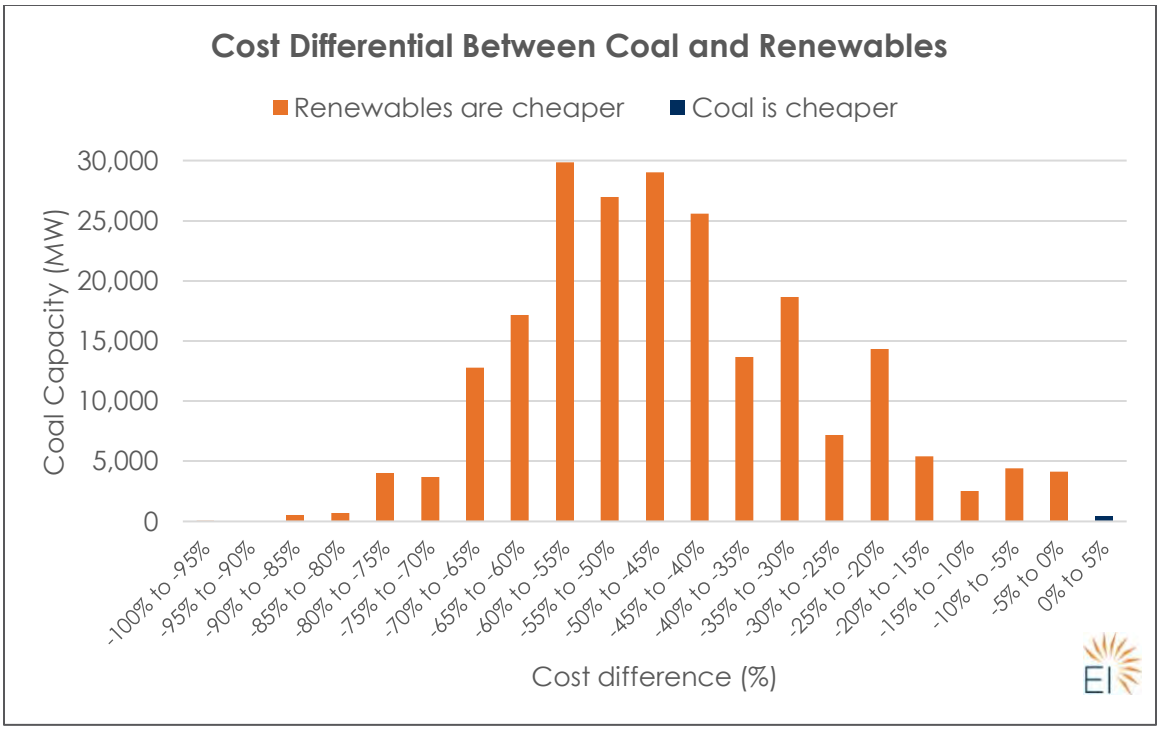


Figure 8. Aggregated plant capacity shown as percent difference between renewables LCOE and coal going-forward cost. The orange bars indicate capacity where renewables are cheaper than coal and coal is deemed "uneconomic." The one blue bar indicates the sole plant that is still cheaper to operate than replace with renewables.

Local replacement of coal

Local solar and wind

For 199 of the 210 plants studied we find that local solar replacement is more economic than coal, based on energy generation alone, and for 75 plants it is the cheapest option entirely. Local wind is also a viable option for many plants, with 104 plants having cost-effective local wind resources and 13 having local wind as the cheapest option. For 98 plants, both local wind and local solar were

cheaper than coal. While we did not study any combinations of the two, this result indicates that a portfolio that includes both local wind and local solar would likely be a viable option with additional reliability value near many plants.

In these local replacement scenarios, we looked at replacing all the annual electricity generated by a given coal plant with either local wind or local solar within 45 km of the plant. This allowed us to assume lower interconnection costs[xi] (a significant barrier for new projects)[21] while taking advantage of the IRA's energy community tax credit bonus. In nearly all cases we studied, the reduced interconnection costs and added tax credit compensates for potentially lower resource quality when restricting site selection in areas close to the plant. We find particularly good resource quality in the local solar scenario, where 191 plants have sufficient sites nearby such that their generation can be replaced within 20 km.

Solar plus storage stepping in at North Valmy

In Nevada, NV Energy has already realized the cost and community benefits of using solar plus storage in place of the 567 MW North Valmy Generating Station, near Winnemucca. Two new solar plus storage facilities located within the same county will replace this plant when they are completed by 2025. The two replacement projects will provide 250 MW solar capacity plus 200 MW of storage, and 350 MW of solar plus 280 MW of storage. These projects will also create several hundred construction jobs, and the storage will help shift the solar generation to the times of day it is most needed, serving the reliability needs of the area. This is consistent with our analysis, which finds that it would be cheaper to use solar plus storage up to the full plant's capacity than to continue to run the coal plant. Plants across the country can now follow Valmy's example and effectively decarbonize with solar plus storage.

Local replacement offers three other benefits. First, local replacement can help preserve livelihoods and tax revenue for surrounding communities through the energy transition.[xii] Second, local resource replacement falls into the category of projects that can qualify for loans via the DOE's

[xi] In our modeling, we use ReEDS spur line costs as a proxy for interconnection costs of regional renewables. For local renewables, we assume no interconnection costs because the point of interconnection already exists at the coal plant. This is a simplification—each site will be different and will require an interconnection study or transmission plan to ascertain the interconnection costs.

[xii] New renewable energy installations are only one piece of the puzzle when it comes to community transition as they typically do not provide as many jobs or as much tax revenue as a coal plant. While local energy replacement can contribute, further community re-development and economic diversification is needed, as discussed further in the policy recommendations section.

EIR program, as the projects would be a direct reinvestment in energy infrastructure. Our analysis shows investment in local solar resources could drive $589 billion in capital investment to energy communities across the country (see Figure 9).

Third, siting renewables in proximity to plants creates the possibility that these new resources could use the existing plant's grid interconnection. Recent analysis of PJM's interconnection process shows that the median interconnection cost from 2020 to 2022 grew ten-fold over the costs from 2017 to 2019, largely due to transmission network upgrade costs.[22] While we considered reduced interconnection costs for local resources, the advantage of local replacement could be even more considerable as the cost of the line is only a part of the problem. For clean energy projects across the country, long interconnection wait times are also a major hurdle to overcome.

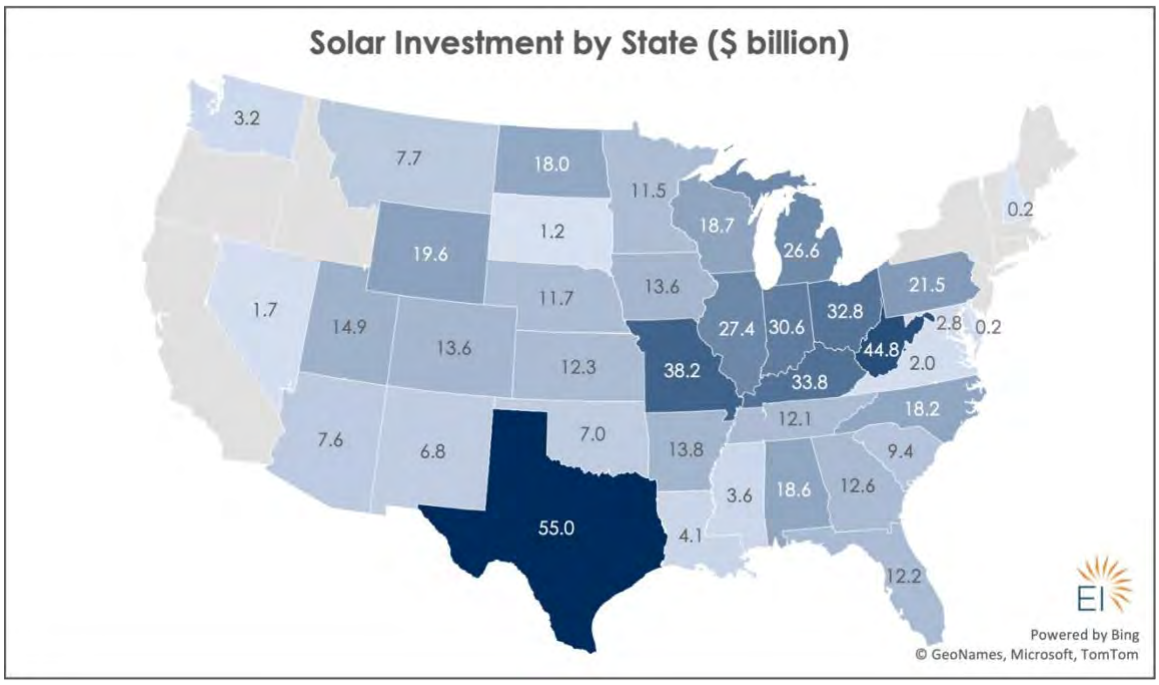


Figure 9. The solar capacity needed to provide enough energy to make up for coal generation across the country would drive hundreds of billions in investment. States with no investment number had no plants in our data set.

Local solar plus storage

We followed up on our local solar scenario by looking at a solar plus storage replacement option for each plant that includes local solar energy plus four-hour batteries to provide additional capacity value and higher market profitability in some cases. We find that the savings available from switching from coal generation to local solar generation can finance 137 GW of four-hour battery capacity at a price of $330/kWh across the coal fleet.

For more than a third of the coal capacity studied, we find that in addition to energy generation replacement with local solar, 80 percent or more of the plant's capacity can be replaced with four-hour batteries at a combined levelized cost that is still less than the going forward cost of the plant. For the remaining plants, the percentage of capacity that can be economically replaced is still quite significant: We find that savings from renewable generation could fund storage at more than 50 percent plant capacity at 136 plants.

Renewable options cheaper than expensive upgrades at Mitchell plant

In 2021, American Electric Power determined it would likely be more cost-effective to retire West Virginia's Mitchell Power Plant than pay for expensive pollution control upgrades required by the U.S. Environmental Protection Agency (EPA). However, the West Virginia Public Service Commission (PSC) ruled that the utility had to keep the plant open, and that WV ratepayers must pay for the upgrades. At the same time, in Kentucky and Virginia, who were also receiving power from the plant declined to make their state's customers pay, leaving West Virginians to shoulder a $448 million price tag. Our analysis shows taking advantage of regional wind resources would be 48 percent cheaper than continuing to run this polluting plant. Replacement with local solar and battery storage would be 50 percent cheaper and would provide the reliability the PSC seeks while saving ratepayers hundreds of dollars every year.

This local solar plus storage arrangement has at least three advantages:

First, solar plus storage provides resources with a significant capacity and ancillary service value at the same place on the power grid, addressing in part possible reliability concerns that may be associated with coal plant retirement.

Second, the new storage ITC means batteries do not need to be co-located with renewables to take advantage of the tax credit. This means that while local renewables may need to be sited a short distance from the plant, storage can be placed directly at the coal plant site and use existing electrical infrastructure to act as a central collection site for renewables. This arrangement also bolsters economic development opportunities in coal communities.

Third, combining solar and storage empowers a gradual coal phase-out, benefiting communities and grid reliability. Electricity generated from coal can be reduced, while keeping the coal boiler and generator available for emergencies. If needed, the generator can eventually be transformed into a piece of grid regulation hardware requiring no boiler, and batteries can store and release renewable energy to make the whole system available at times of highest grid demand. Renewable energy can

be a part of an economic diversification package that may include other re-purposing of the site, such as a plant in Michigan that was re-developed into an insurance company's headquarters.[23]

The reliability implications of coal plant retirement should be evaluated for each specific plant. A one-to-one replacement is often not necessary given the capabilities of the remaining power plant fleet. For example, the battery capacity necessary to take over the reliability burden of any given coal plant is varied, depending on the role of the plant and broader resource mix, and it is not needed at all in many cases. Wind and solar (especially in a complementary combination) already tend to provide a measure of capacity value to the regional grid. Other assets like faster, more flexible gas units or behind-the-meter resources may already be carrying more of the regional reliability burden, and transmission expansion can help reduce the need for dispatchable generation for resource adequacy as well. Therefore, coal capacity is not always necessary for reliability depending on the resource adequacy in each region as determined by the balancing authority.[24]

Figure 10 shows the percentage of battery capacity at each plant that can be funded by coal replacement with local solar, providing a range of options for combining renewables with storage.

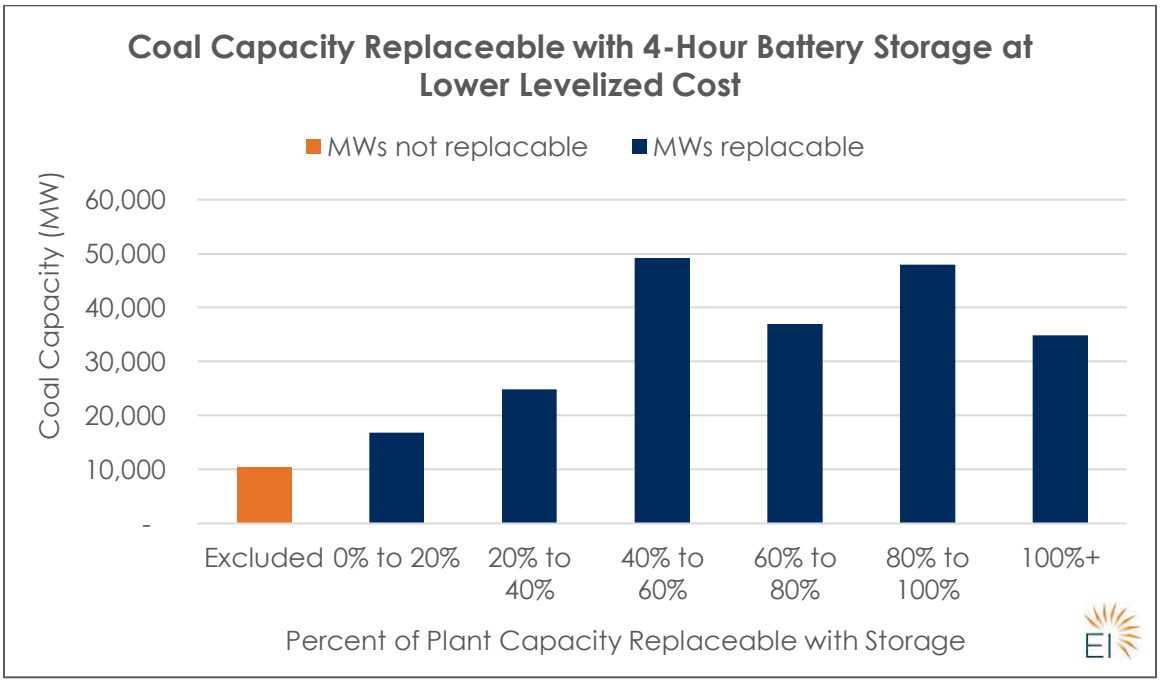


Figure 10. Coal plant capacity (in MW) by the percentage that can be replaced using only coal crossover savings. "Excluded" indicates plants for which local solar generation was available but was not cheaper than coal.

The economics of battery replacement for capacity are highly dependent on battery costs. For the analysis above, we used $330/kWh as the cost of storage, which is the 2021 cost for storage in the NREL 2022 ATB.[25] Our cost accounted for the new standalone storage ITC and energy community tax credit. To study the sensitivity of these findings to battery prices, we evaluated the potential for capacity replacement across prices ranging from $100/kWh to $400/kWh (see Figure 10).

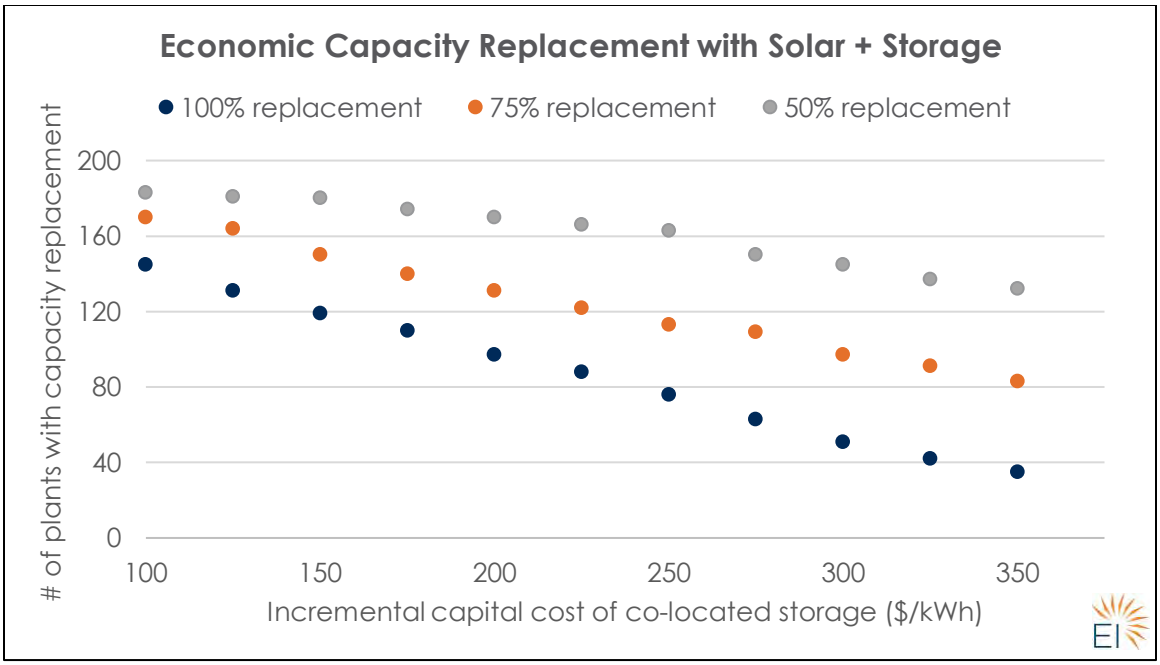


Figure 11. Economic battery capacity relative to battery price by percent capacity that can be replaced at each plant.

Utilizing additional financing to fund local resources: Ameren's Rush Island Plant

It is important to note, however, that fuel savings are not the only source of savings that could help finance replacement batteries in a coal-to-local renewables swap.

For example, Ameren's Rush Island power plant in Missouri is not a strong candidate for financing batteries solely with savings from switching to local renewables. Yet by also accounting for needed upgrades, the plant's remaining balance, and reliability concerns, the case for financing batteries for reliability value becomes stronger.

Ameren was planning to retire the 1,195 MW coal plant in September 2022 partially due to the expense of adding court-ordered selective catalytic reduction (SCR) to address air pollution

noncompliance, with a price tag of $310 million[xiii] to $1 billion.[26] Unfortunately, because early retirement could cause severe voltage stability problems leading to cascading power outages, the Midcontinent Independent System Operator (MISO) sought to keep the plant online and received Federal Energy Regulatory Commission (FERC) approval for a 12-month system support resource agreement to be renewed annually.[xiv] According to the grid operator, potential renewable energy additions or possible demand-response programs wouldn't adequately address the location-specific voltage problem. However, due to the geographic nature of the potential voltage instability, local renewables coupled with batteries could go a long way toward mitigating this concern without waiting for the transmission upgrades MISO deemed necessary.

Our initial analysis finds that switching to renewables could generate savings to pay for replacing replacement of only 4 percent of the plant's capacity with batteries. However, the IRA now creates new possibilities. Because Ameren faces capital expenditures in the $300 million to $1 billion range, and already holds an estimated $600 million for the plant in its rate-base (interest on which is paid by its customers at standard utility rate of return), existing state public utility commission securitization authority could be used to refinance this obligation in combination with the EIR program, generating much greater customer savings.[xv] Investing these savings in four-hour battery storage could match 85 to 165 percent of the plant's capacity. Furthermore, batteries would only be necessary if the local renewables on their own were not sufficient to provide voltage support or if the proposed transmission solutions proved too slow or expensive.[xvi]

New IRA financing and tax credits make replacing coal plants with a combination of local wind and solar power supported by batteries an attractive option for most coal plants in the U.S. Such replacement can be done with a minimum of disruption to the grid while keeping jobs in affected communities—not to mention the great improvements to public health from reduced pollution.

POLICY RECOMMENDATIONS

Our analysis makes it clear the comprehensive the IRA tax incentives have created a favorable policy environment for the coal-to-clean transition. However, the transition can be made even more cost-effective if utilities harness the IRA's loan and grant programs and use best practices to assess cost-saving replacement options.

[xiii] Assuming $250/kW all-in costs. See https://www.powermag.com/estimating-scr-installation-costs/.

[xiv] MISO identified four transmission upgrades that are needed to maintain voltage on the grid, with the last one expected online by June 2025, according to the grid operator. See https://www.utilitydive.com/news/ameren-missouri-coal-rush-island-miso-ferc/630226/.

[xv] The interest rate on the securitized loans or government-backed loans through EIR are assumed to be 2.95 percent, or the average of the 20-treasury yield across the last 10 years plus 0.375 percent. Missouri law already allows for coal plant securitization.

[xvi] While MISO investigated replacement of the plant with renewable energy, it does not appear that MISO considered renewables in geographic proximity to the plant.

Planners and policymakers should make sure they are not caught unprepared by a wave of retirements, and that replacement renewables and complementary flexible resources can be deployed in a timely manner. Advocates and policymakers interested in capturing the economic and public policy benefits of shifting away from coal can take several actions to ensure that power plant operators take advantage of the moment by requiring utilities to account for IRA incentives and funding programs in planning and procurement. Finally, our analysis suggests that IRA provisions designed to encourage a just transition for coal communities are well positioned to spur new investment in generation and grid balancing resources in the immediate vicinity of existing plants, but experience has shown that a just transition will only happen with the careful attention of legislators and regulators alongside local communities.

Reliability assessment keeping expensive Indian River plant online

Delaware's only remaining coal plant, Indian River Generating Station, was planned for retirement by June 2022—until the grid operator, PJM, requested it remain open until 2026. PJM had determined that transmission upgrades would be needed to stabilize the grid before the plant could be taken offline. The plant, which only has one remaining unit, is historically the worst polluter in Delaware and also the eighth most expensive plant we analyzed due to low capacity factor and high estimated fuel costs. Local replacement of this plant could assuage reliability concerns by providing generation and capacity needs at the same location on the grid. Our local analysis finds that 246 MW of storage could be funded via savings. At over 50 percent of the plant's capacity, this is a good candidate for re-assessment of reliability needs.

Preparing the way for coal transition

Improving interconnection and transmission processes

The Rush Island Power Station example discussed above is not unique and blocking retirement of uneconomic plants due to broader system stability concerns and transmission requirements harms customers. To move forward while maintaining reliability, independent system operators (ISOs) and regional transmission organizations (RTOs) should proactively study solutions that can enable plant retirements. The alternative—overriding utility retirement plans and requiring FERC approval for expensive stopgap payments to keep high-cost plants running—is not good for utilities or their customers.

Our analysis shows that post-IRA, almost every coal plant has reached its economic tipping point. As pollution standards and clean energy policies continue to worsen coal plant economics, ISO/RTOs will increasingly encounter situations where innovative resource

portfolios will be needed to economically and reliably replace coal plants, including transmission. As neutral arbiters of just and reasonable rates, system operators must be ready to enable cheaper electricity and public policy goals by allowing utilities to retire uneconomic plants. Proactive transmission planning and deployment, alongside improvements to interconnection processes are both crucial to prepare for uneconomic plant replacement.

Absent regulators stepping in, retiring a plant is much easier than building a new renewable project. Price signals may induce coal retirements before new renewable projects can be approved and built to take their place. The growing interconnection queue backlog is of particular concern here. As of 2022, the two largest power markets in the U.S., MISO and PJM, had about three times more renewables capacity waiting in the queue than they had existing coal capacity.

For PJM, this backlog was deemed insurmountable. While PJM works through its existing interconnection requests, it will not review new requests until early 2026. It is clear that additional measures to improve the interconnection process, including better regional transmission planning, are needed to avoid similarly extreme measures in the future.[27] FERC is currently considering interconnection policy changes, but state public utility commissions can also help by examining their state's queue and assessing whether proactive transmission buildout could connect cost-effective clean energy. In states outside an ISO/RTO, states hold sole responsibility for proactive transmission and planning process reform to reduce wait times and hasten the pace of in-state clean energy investment.

Building local: accelerating deployment while maintaining reliability

Action from FERC and other policymakers on interconnection reform and transmission buildout cannot come too soon. A recent brief from Lawrence Berkeley National Lab (LBNL) analyzing interconnection costs in the PJM region finds that, alongside the tremendous lengthening of the interconnection queue, interconnection costs have increased substantially in recent years.[28] The main driver behind these increases has been broader network upgrade costs, reflecting system changes due to the influx of renewables and the fact that optimal renewable sites are often far from the coal they might replace.

There is no doubt that variable renewable resources are fundamentally different from dispatchable fossil generators, but variability does not imply unreliability. Studies are clear: A coal-free U.S. electricity system can be dependable.[29] Yet renewables do require a different resource adequacy framework, which makes resource diversity, energy sufficiency, regional and interregional transmission, and demand response more important. As system operators design new resource adequacy metrics, regulators should support them by defining minimum resource adequacy requirements and soliciting cost information.[30]

In a high-renewables environment, interregional electricity transfer can help manage local weather variation, providing higher reliability at lower cost. RTOs and regulators can enable interregional

coordination by expanding planning areas or subsidizing transmission lines that provide for specific reliability needs. Finally, regulators and state legislatures can require resources that bolster reliability like energy storage has become a cost-effective way to integrate renewables, as this report shows. However, storage still lags in investment. A legislative storage mandate, like the one passed in California in 2013 can help accelerate storage deployment.[31]

Ultimately, building out the network to include and adapt to some of the best available renewable resources, evolving the bulk power system's resource adequacy framework, and improving inter-regional coordination supports a least-cost, reliable electricity system given the new IRA incentives. But, as is evidenced by the delays described above, all this takes time. Building local resources closer to or at the same site as coal plants could dramatically accelerate clean energy deployment while providing significant incremental reliability value.

Prior to the IRA, local replacement was not always economic on an annual generation cost basis relative to the cost of maintaining a coal plant. However, to support a just transition, the IRA includes additional incentives for building new clean resources near coal plants or "energy communities." Our analysis shows that local wind or local solar plus storage could create a cheaper electricity portfolio than nearly every plant, while delivering the same amount of electricity and providing significant reliability value. Even if a coal plant weren't completely shut down, it could work in tandem with cleaner, cheaper resources fed through the same point of interconnection to deliver cheaper, cleaner electricity without materially affecting the transmission system and system operations (it might even improve these). Utilities, ISO/RTOs, and state and federal regulators should move swiftly to develop standard templates that allow for coal plant hybridization or replacement with clean portfolios. These templates would have to be generically robust enough to satisfy system reliability and stability concerns under a variety of conditions to replace coal without a lengthy interconnection process.[xvii]

Proactively pursuing transition

Re-evaluation of integrated resource plans and improving competitive procurement

While measures to proactively plan for and better accommodate new renewable projects are necessary to capture the huge economic benefits of transitioning expensive coal plants to cheaper renewables, they are not sufficient. Utility integrated resource plans routinely overestimate new renewable costs, and the IRA programs will likely make these overestimations even higher. Any

[xvii] There may be concerns about undermining competition if some resources are allowed to skip ahead of the line, but presumably standard templates will involve costlier investments than what might be proscribed in a more specific interconnection study. In any case, it makes sense to recognize that providing replacement resources at or near an existing resource is easier and simpler for the network, and the benefits of just transition and accelerated deployment should be balanced against competition concerns.

investment plan or market-based solicitation for renewable contracts completed before August 2022 is now out of date. Regulators can expect independent power producers to offer lower bids for just about any clean energy technology. Under their authority to set just and reasonable rates, PUCs should insist that utilities redo integrated resource plans and resource solicitations, despite the procedural complexity. For example, advocates have already submitted evidence to the North Carolina Utility Commission that such a re-examination would be prudent for Duke Energy's Integrated Resource Plan and Carbon Plan.[32]

In addition to cost updates, integrated resource plans should account for the benefits of location-based procurement to replace coal generation. In New Mexico, the Energy Transition Act required the Public Service Company of New Mexico to site some of the replacement resources for the San Juan Generating Station in the nearby school district to replace lost tax revenue.[33] Because of location-specific tax credit bonuses, traditional regulatory requirements to minimize consumer costs now require an examination of local investment in replacement wind, solar, and battery resources.

FERC and NERC should work with the ISO/RTOs to create standardized approaches to gradual replacement with local resources and eventual development of reliable resource portfolios that include renewables, transmission, and emerging technologies like power electronics and synchronous condensers.

In addition to accurately assessing renewables during planning processes, enabling competitive procurement is crucial to getting steel in the ground. Even before the IRA, unsubsidized renewables were the cheapest new resource in most of the country. However, regulators can have difficulty discerning the true cost of clean energy or comparing variable clean resources with dispatchable fossil power providing different services. Such assessments generally depend on limited utility information.

All-source procurement is a way around this—it is a well-established but underutilized process that requires the utility to provide assessments of resource need, then bid these services to the market. For example, Xcel Energy Colorado achieved record-low wind, solar, and storage prices that shocked the electricity world with an all-source procurement in 2018, avoiding costly investments in gas and accelerating coal retirement.[34] PUCs should establish all-source procurement rules that link these solicitations as inputs to integrated resource planning processes that ultimately result in resource procurement—a key part of the Colorado planning process.[35] These solicitations also provide the opportunity to assess and define needed system reliability attributes after coal plants retire and allow supply-side, demand-side, transmission expansion, and regional market resources all compete to fill that need.[36]

Utilizing IRA funding and financing programs

Our comparison of the going-forward costs of existing coal plants with regional or local renewables doesn't capture all the economic advantages of such a transition. The IRA also includes measures that facilitate savings from lower cost financing.

First, the IRA created a $9.7 billion fund for rural electric cooperatives to reduce GHG emissions via a myriad of methods. With cooperative assets highly tied up in coal and without the same access to capital as investor-owned utilities, the transition to cheaper clean resources can be particularly challenging. To take advantage of these funds as soon as possible, co-ops should develop clear plans that use new clean energy and coal generation replacement to achieve deep GHG emissions reductions, in accordance with the IRA's statutory language.[37] For their part, states should provide resources to support the planning and application processes. With nearly 18 GW of plants in this analysis majority-owned by cooperatives, this program, if used to its greatest potential, could spur billions in rural economic development.

In addition to rural cooperative funding, the IRA provides substantial debt refinancing potential, when paired with reinvestment in new clean energy infrastructure. While we find all but one plant are uneconomic when compared to replacement with new wind and solar, many plants have large debt burdens that hamper the customer savings available from clean energy replacement. Some states have explicitly allowed utilities to refinance these remaining balances via securitization, but now all power plant owners have access to flexible low-cost capital to finance new clean energy projects reusing coal-

Cleaning up coal ash at the G G Allen Steam Plant

In 2014, the now-retired Dan River Power Station leaked 39,000 tons of coal ash into the Dan River—leaving residents without drinking water for years and requiring a $3 million clean-up. It also kicked off an investigation of Duke Energy in North Carolina that found all 14 coal plants in the state were leaking coal ash. G G Allen has the largest amount of coal ash on site out of all the plants with 19 million tons of that need to be removed. In addition to this high pollution impact, it is also the second most expensive coal plant to run in the U.S. according to our analysis. But it needn't be this way. North Carolinians can have clean air and water with cheaper clean energy. All four renewable scenarios in our analysis were cheaper than running the G G Allen plant. In addition to clean energy replacement, the use of a DOE loan guarantee could save ratepayers even more by using low-cost financing for replacement infrastructure including the coal ash remediation.

plant infrastructure via the DOE's new loan program.[38] PUCs should require utilities to update prior investment and coal retirement plans to reflect the low-cost capital now available for reinvestment in communities.

Particularly for independent power producers, which own 23 percent of the coal capacity we studied, these DOE loans will be significantly cheaper than those without government backing. The loan guarantee must be used to reduce GHG emissions and reinvest in that same community.[39] Funds can be used for a wide range of applications including partial or full coal replacement with renewable resources, transmission and storage, and even remediation of former fossil fuel sites, improving environmental conditions and serving as another source of job creation for the local community. Given the flexibility of the program, this is far from an exhaustive list.To smooth community transition, loans need not require immediate plant retirement, but instead could support projects that gradually reduce coal while increasing renewable generation and diversifying the community's economy.[40] The local renewable replacement plus storage scenario we study fits this approach.

Just transition in Colorado

In 2019, the Colorado legislature passed a bill creating the first Office of Just Transition (OJT), and just in time. With six coal mines and seven coal-fired power plants still operating, small communities, particularly in Western Colorado, risked near-total economic collapse. Since the legislation passed, the OJT created a Just Transition Action Plan to support economic diversification and job retraining. The town of Nucla illustrates how this plan can work. When their coal plant shut down three years ahead of schedule, it was the largest employer. The plant also provided nearly half the tax revenue that supported the whole region—including the fire department and school district. Residents were rightfully concerned, but Nucla has worked with OJT to transition their economy to focus on tourism and small businesses. Nucla still has a way to go and more funding is needed, but Nucla shows how pre-emptive planning can help ease the sting of coal closures. Now, newly appropriated OJT funds will continue to help Nucla restructure while preparing other Colorado coal communities.

Just transition for affected communities

State PUCs, legislatures, and state energy offices all have a role to play ensuring a just transition for coal communities. New IRA funding mechanisms mean traditional, least-cost utility planning practices now require reinvestment in communities whose economic prosperity depends on coal plants and coal mining. Assessing and including reinvestment in

these places is now essential to "least cost, best fit" resource planning.

Of course, the nuances of community needs are more complex than simple economics, and fully considering viable transition strategies in integrated resource plans is not possible unless state regulators and utilities seek input from affected communities at the beginning of the planning process. Seeking community input is not typically part of existing integrated resource planning processes, and it can be challenging for resource-constrained PUCs or utilities to incorporate new, innovative approaches to stakeholder engagement and ultimately community transition.[41]

State legislation should require PUCs and utilities to plan for community transition and assess the value of federal loan guarantees and tax credits for community transition, starting with outreach in an investigatory proceeding that provides access by holding commission forums in those communities. With this input, utility investment plans can better meet community economic needs, which can include tax revenue, workforce development, infrastructure investment, pollution clean-up, and community ownership models like community solar.

While the IRA has several reinvestment programs, energy communities cannot rely on clean energy alone to fully replace coal jobs and tax revenue. However, local clean energy can provide the opportunity for additional industrial development if new data centers or industrial facilities like synthetic fuel producers seek direct on-site access to low-cost clean energy. Proactive diversification of local economies is another path for success, which would benefit from state resources. The transition can even begin before the plant retires—gradual replacement and interconnection could ramp up in anticipation of the plant's eventual retirement, growing jobs and reducing pollution along the way.

Legislators should consider creating and funding a just transition office, following Colorado's example, to help coal communities develop transition plans. In addition to these legislative actions, PUCs can consider putting community transition funding into rates or creating ratepayer and shareholder cost sharing arrangements, similar to the arrangement made following closure of the coal plant in Colstrip, Montana.[42]

CONCLUSION

The economic case for replacing highly polluting and expensive coal-fired generation with clean energy is stronger than ever. Our new analysis, based on 2021 data, already surpasses our previous projection for 2025, finding that 99 percent of all U.S. coal plants are more expensive to run compared to new clean energy generation. Local replacement is more attractive than ever due to the IRA's new incentive and funding programs. Including battery storage along with local renewable generation can be an economic way to bolster the reliability value that these renewable projects provide to the grid. Building new wind or solar before completely retiring existing coal can be a recipe for success, a paradigm supported by the DOE's new loan authority. The near-complete crossover of coal economics versus renewables makes the imperative to transition clearer than

ever before, but policymakers, utilities, consumers, and coal-dependent communities must recognize the benefits and seize this moment.

APPENDIX: DETAILED METHODOLOGY

Coal Costs

Our goal was to develop an accurate estimate of the going-forward cost of running U.S. coal plants using publicly available data from EIA, FERC, and EPA. In assembling a master list of U.S. coal plants, we restricted ourselves to plants running mostly coal (excluding wood waste and petroleum coke burning units) operated by utilities and independent power-producers (sectors 1 and 2, in EIA parlance), excluding plants used for combined heat and power, for which the economics are more complicated because these plants receive other revenues from providing heat.

As a matter of convenience, we limited ourselves to coal plants in the lower 48 states and excluded a few plants for various practical reasons like corrupted or unavailable data. The companion spreadsheet to this report lists these in detail. In any case, these cuts did not materially reduce the number of GWs of capacity we covered. Finally, we grouped boilers and generating units together at one location as single plants, while excluding boilers and generating units fueled mostly with natural gas. The final master list of 210 coal plants is available in the companion spreadsheet to this report.

The going-forward cost for each coal plant in our master list comprises three principal components

- The cost of fuel on a per MWh of coal generation basis.
- The operation and maintenance cost of each plant levelized over the total generation from each included boiler and generating unit.
- The average annual going-forward costs for capital investments needed to replace and upgrade part of the power plant levelized over the total generation from each included boiler and generating unit.

This Appendix reviews our methodology for each of these three elements in more detail.

Cost of Fuel

Our principal method for calculating fuel cost for any given coal plant comes from first computing its cost of energy inputs in dollars per million British Thermal Units ($/mmBTU). We need a heat rate in mmBTU/MWh to convert this input into a cost of delivered energy in $/MWh. The heat rate is a number particular to any given plant that varies according to any number of contextual factors (e.g., fuel-type, technology, age, outside temperature, capacity factor). As a matter of simple expediency, we use a heat rate for each power plant defined by the sum of BTUs from all non-

natural gas fuels burned at that plant in 2021 divided by all the net-generation from these fuels as defined in the first page of EIA Form 923. We used this to convert input fuel costs into output electricity fuel costs.

We then used EIA data on fuel contracts paid by the plant; listed on page 5, "Fuel Receipts and Costs," of EIA Form 923. The EIA 923 spreadsheet lists fuel contracts with heat contents (mmBTU per fuel unit) and price paid in cents per mmBTU. From these contracts we can establish an mmBTU-weighted cost per mmBTU for coal, which we use as an input cost for that plant. Note that this does not include fuel processing costs that might be covered in values reported to FERC. Probably the most important example of fuel processing comes from plants that report burning so-called "refined coal" on one part of Form 923 while at the same time reporting direct purchases of other coal, e.g., bituminous coal, on another part of the form. This discrepancy is due to the fact that "refined coal" involves processing purchased coal (usually by spraying it with certain chemical agents) to reduce emissions from the smokestack. It is hard to know how much this extra processing costs on a per mmBTU basis, but we understand that the economic rationale for doing so is driven mostly by a tax credit. Historical trend analysis of some plants that burn "refined coal" shows that they sometimes choose to apply this processing and sometimes not reflecting, in our opinion, the likelihood that there is only a small impact on fuel costs to "refining" after netting out processing costs and tax credit income.

For plants that do not report input fuel costs to a regulator, however, other less plant-specific sources of information were required. In these cases, instead of specifically reported plant data, we used state-based data on the average cost of coal from EIA. To accurately reflect the diversity of coal types and relative mix of types that various plants consume, we used a combination of total plant coal consumption and state average coal costs from EIA as well as historical fuel consumption trends at the plant to estimate source coal type and marginal fuel costs. We used the following procedure:

Step 1: Extract the various mmBTU quantities of coal by type used by the boilers in each coal plant of interest from the 2021 EIA Form 923.

Step 2: Link each coal type with a state benchmark input fuel price in $/mmBTU. We establish that benchmark price by combining information on electric power sector coal prices by coal type and plant state from EIA's Coal Data Browser with coal heat content (mmBTU/ton) by state and coal type, also from EIA's Coal Data Browser (if heat content for a given coal type was unavailable for the 2021 reporting year, we used the most recent year).

Step 3: Tag "refined coal." One type of coal that appears in boiler consumption figures but not price tables is "refined coal." To price this type of consumption, we assigned each instance of "refined coal" to a coal sub-type. Depending on the plant, the source coal for "refined coal" might be bituminous, sub-bituminous, or lignite. With some painstaking work, we were able to infer from other nearby plants and historical fuel consumption trends at the plant which coal type was being refined with high confidence.

Step 4: Combine coal types to get a plant fuel cost. We combined price and consumption levels at each plant to get a weighted fuel input cost in $/mmBTU. We then converted this to $/MWh using the heat rate—just like the plants that report their input fuel costs.

Operation and Maintenance Costs

We used plant-by-plant operation and maintenance estimates obtained from the Electricity Market Module (EMM) in EIA's North American Energy Modeling Systems (NEMS). For some plants, no NEMS value for operation and maintenance was available and we used a national average value.

Going forward capital costs — National Energy Modeling System (NEMS)

The third element in our overall coal going-forward cost estimate is the going-forward capital cost. For this element we used a fairly simple method. We started by taking the average age (weighted by generator capacity) of a given coal power plant and compared it to the EIA NEMS table found in Figure 12. From this NEMS table and the average age of the plant, we obtained a per kW-year going-forward cost, which we multiplied by the overall capacity of the plant. We then divided by the total net MWh output from the plant (defined by the included set of generators) as reported on EIA Form 923. This includes any natural gas-fueled generation and results in a $/MWh, which then factors into the complete coal going-forward cost.

Age	Annual Capital Investment Requirement ($/kW-yr)
0 - 10 years	$ 17.16
10 - 20 years	$ 18.42
20 - 30 years	$ 19.68
30 - 40 years	$ 20.94
40 - 50 years	$ 22.20
50 - 60 years	$ 23.46
60 - 70 years	$ 24.72
70 - 80 years	$ 25.98

Figure 12. NEMS estimates of going forward capital costs by age of plant.

Renewables Costs

Identifying Renewable Energy Sites

We use NREL's ReEDS model that provides high spatial resolution solar and wind potential datasets in the U.S. The solar and wind potential numbers in ReEDS are, in turn, taken from the Renewable Energy Potential (ReV) model, which assesses the wind and solar energy potential at 11.2 km x 11.2 km spatial resolution after applying comprehensive exclusion criteria, including land cover, elevation, slope, environmentally sensitive areas, local siting regulations, etc. Across the continental U.S., ReV and ReEDS identify nearly 50,000 individual solar sites totaling a potential of 96,000 GW, and around 50,000 individual wind sites totaling a potential of 6,600 GW. The ReEDS model also provides annual capacity factors at each of these sites, which are estimated using the wind speed, solar irradiance, temperature, and other weather parameters from the Wind

Integration National Dataset (WIND) and National Solar Radiation Database (NSRDB). More information on this can be found in ReEDS documentation.

Technology Costs

We run the ReEDS model using technology costs from ATB 2022 and IRA incentives and estimate the wind and solar LCOE at each of the 50,000 sites. ReEDS uses a comprehensive list of parameters to estimate a site-specific LCOE including capital costs, fixed operation and maintenance costs, equity costs, interest rates, construction costs differentiated by location across the U.S., construction period, ITC and PTC incentives per IRA, tax equity haircuts, depreciation, and taxes (see Figure 13). Additional details on LCOE estimation could be found in ReEDS documentation.

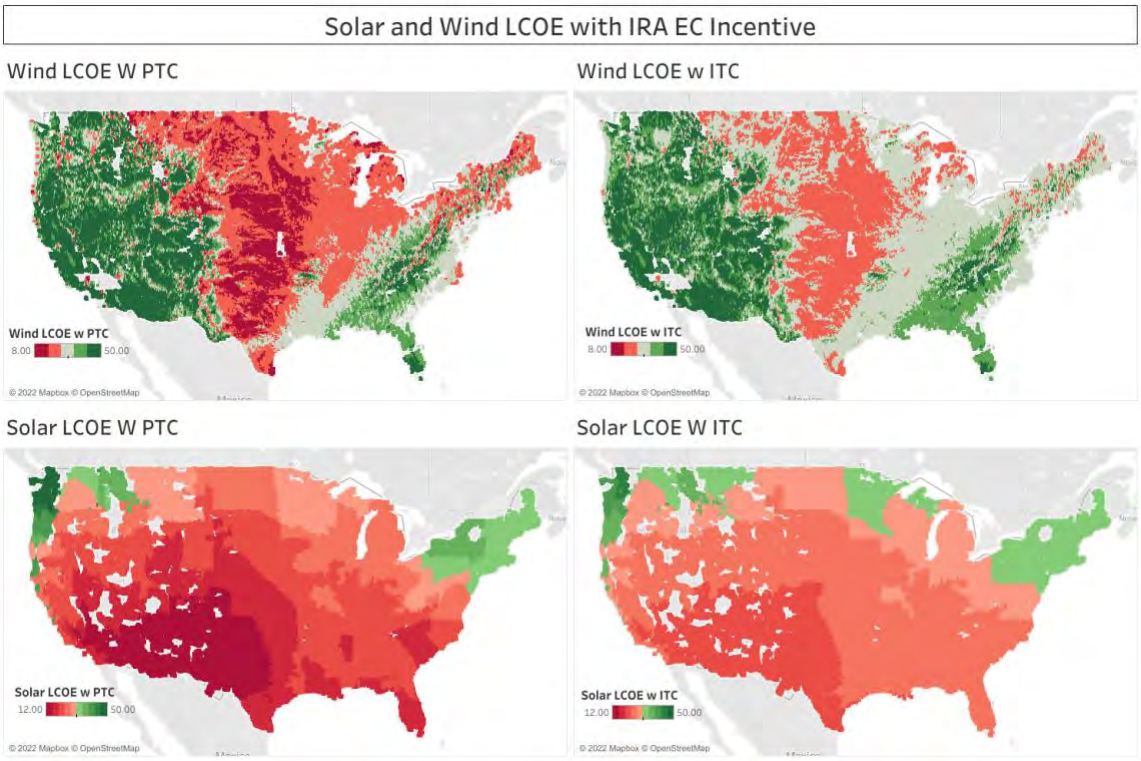


Figure 13. Wind and Solar LCOE including IRA incentives (including energy community) at each of the individual 50,000 sites across the U.S.

Assessing Hyperlocal Potential and LCOEs

The objective of this exercise is to assess the physically closest (hyperlocal) solar or wind resources that could replace the generation from each coal power plant in the country. We start with the location (latitude and longitude) of each of the 210 coal plants in the US. We then create concentric circles around each coal plant with radiuses starting from 5 km up to 45 km in increments of 5 km. Within each of these concentric circles, we identify the solar and wind sites that fall within that circle and estimate the site-level capacity and annual generation potential for solar and wind resources separately, using the high-resolution solar and wind datasets available from ReEDS, as described earlier. We then estimate the minimum circle radius ("hyperlocal circle") needed to replace the annual generation from each coal power plant with solar or wind resources. Within each hyperlocal circle, we assume that the solar and wind projects get the Energy Community Tax Credit per IRA and will not incur any interconnection costs since they could continue using the coal plant interconnection. We weight the site-level LCOEs within each hyperlocal circle by the site-level capacity potential to arrive at a weighted average hyperlocal LCOE to replace the generation from each coal power plant.

We find that annual generation at almost all coal power plants can be cost-effectively replaced by solar resources within a 20 km radius. The minimum radius for wind is much higher.

Regional LCOEs

In addition to the hyperlocal LCOEs, we also estimate the regional LCOEs in the regions where coal plants are located. The ReEDS model divides the contiguous U.S. into 134 regions which are generally aligned with the utility territories (see Figure 14). These regions never cross state boundaries

The rationale for estimating the regional LCOEs in addition to the hyperlocal LCOEs is that the higher-quality resources might not be available in the near vicinity of the coal plants but slightly farther away, and so from the perspective of the developer, it might make sense to move further from the coal plants to access the higher quality resource. This is more important for wind as wind speeds can vary significantly over short distances. As compared to wind, solar is more energy dense, as we can get almost 10 times the capacity of solar in the same amount of land as wind.

The methodology used for estimating regional LCOEs is very similar to that of hyperlocal LCOEs. For each coal plant, we sort the wind and solar sites available in that region (i.e., ReEDS balancing area) by LCOE and choose the best sites to replace the coal generation. For selected sites within each region, we capacity-weight the site-level LCOEs to estimate the weighted average regional LCOE. For the regional LCOE, we do not account for the Energy Community tax credit available in IRA. We also add the interconnection costs to the LCOEs as we assume that these sites may not be able to access the existing coal power plant interconnection.

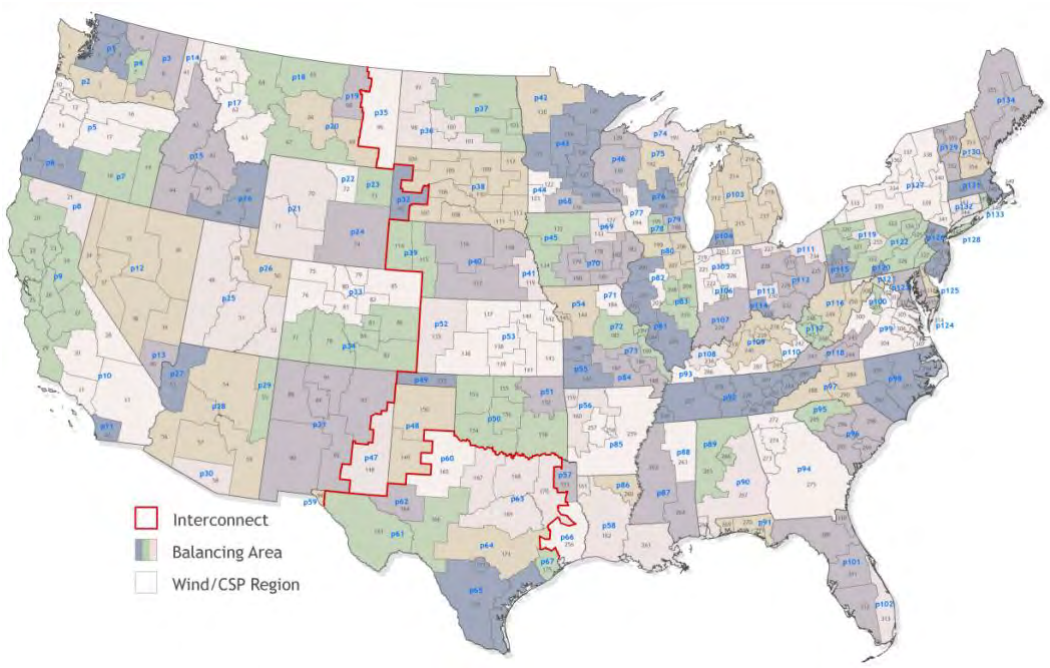


Figure 14. ReEDS balancing areas, used for our regional analysis and roughly corresponding to utility service territories, are highlighted by the different colors in this map. Source: National Renewable Energy Laboratory.

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-9

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

Exhibit 52

MI State Energy Profile

U.S. Energy Information Administration

Michigan State Energy Profile

Michigan Quick Facts

- Michigan has 44 natural gas storage fields with almost 1.1 trillion cubic feet of underground storage capacity, which is the most capacity of any state and almost one-eighth of the nation's total natural gas storage capacity.
- The share of Michigan's total electricity generation from natural gas-fired plants increased from 12% in 2013 to 46% in 2023.
- Renewables provided 11% of Michigan's electricity net generation in 2023, with wind energy providing 64% of that power. Michigan ranks 16th among the states in the amount of electricity generated by wind energy.
- Michigan ranks fifth among the states in residential sector petroleum use and is first in residential sector consumption of propane.
- Michigan’s second-largest power plant by capacity is the 2,186-megawatt Ludington pumped-storage plant on the shores of Lake Michigan. It is one of the 10 largest pumped-storage power plants in the world.

Last Updated: October 17, 2024

- Consumption by Source
- Consumption by Sector
- Production
- Electricity
- Prices

Data

Last Update: May 15, 2025 | **Next Update:** June 20, 2025

Energy Indicators

Demography	Michigan	Share of U.S.	Period
Population	10.1 million	3.0%	2024
Civilian Labor Force	5.1 million	3.0%	Mar-25
Economy	**Michigan**	**U.S. Rank**	**Period**
Gross Domestic Product	$ 659.0 billion	14	2023
Gross Domestic Product for the Manufacturing Sector	$ 107,736 million	7	2023
Per Capita Personal Income	$ 59,714	40	2023
Vehicle Miles Traveled	98,289 million miles	10	2023
Land in Farms	9.4 million acres	30	2024
Climate	**Michigan**	**U.S. Rank**	**Period**
Average Temperature	48.9 degrees Fahrenheit	37	2024
Precipitation	34.4 inches	35	2024

Prices

Petroleum	Michigan	U.S. Average	Period	find more
Domestic Crude Oil First Purchase	$ 64.24 /barrel	$ 70.11 /barrel	Feb-25	
Natural Gas	**Michigan**	**U.S. Average**	**Period**	find more
City Gate	$ 4.00 /thousand cu ft	$ 4.83 /thousand cu ft	Feb-25	find more
Residential	$ 9.55 /thousand cu ft	$ 12.94 /thousand cu ft	Feb-25	find more
Coal	**Michigan**	**U.S. Average**	**Period**	find more
Average Sales Price	--	$ 54.04 /short ton	2023	
Delivered to Electric Power Sector	W	$ 2.41 /million Btu	Feb-25	
Electricity	**Michigan**	**U.S. Average**	**Period**	find more
Residential	18.91 cents/kWh	16.44 cents/kWh	Feb-25	find more
Commercial	14.05 cents/kWh	13.09 cents/kWh	Feb-25	find more
Industrial	8.54 cents/kWh	8.23 cents/kWh	Feb-25	find more

Reserves

Reserves	Michigan	Share of U.S.	Period	find more
Crude Oil (as of Dec. 31)	46 million barrels	0.1%	2022	find more
Expected Future Production of Dry Natural Gas (as of Dec. 31)	1,302 billion cu ft	0.2%	2022	find more
Expected Future Production of Natural Gas Plant Liquids	11 million barrels	*	2022	find more
Recoverable Coal at Producing Mines	--	--	2023	find more
Rotary Rigs & Wells	**Michigan**	**Share of U.S.**	**Period**	find more
Natural Gas Producing Wells	1,308 wells	0.3%	2020	find more
Capacity	**Michigan**	**Share of U.S.**	**Period**	
Crude Oil Refinery Capacity (as of Jan. 1)	140,000 barrels/calendar day	0.8%	2024	
Electric Power Industry Net Summer Capacity	31,538 MW	2.6%	Feb-25	

Supply & Distribution

Production	Michigan	Share of U.S.	Period	find more
Total Energy	562 trillion Btu	0.6%	2022	find more
Crude Oil	11 thousand barrels per day	0.1%	Feb-25	find more
Natural Gas - Marketed	68,132 million cu ft	0.2%	2023	find more
Coal	--	--	2023	find more
Total Utility-Scale Net Electricity Generation	**Michigan**	**Share of U.S.**	**Period**	find more
Total Net Electricity Generation	10,281 thousand MWh	3.0%	Feb-25	
Utility-Scale Net Electricity Generation (share of total)	**Michigan**	**U.S. Average**	**Period**	
Petroleum-Fired	0.1 %	0.4 %	Feb-25	find more
Natural Gas-Fired	35.6 %	39.0 %	Feb-25	find more
Coal-Fired	27.5 %	18.4 %	Feb-25	find more
Nuclear	22.6 %	18.2 %	Feb-25	find more
Renewables	12.4 %	23.6 %	Feb-25	

Supply & Distribution

Stocks	Michigan	Share of U.S.	Period	find more
Motor Gasoline (Excludes Pipelines)	9 thousand barrels	0.1%	Feb-25	
Distillate Fuel Oil (Excludes Pipelines)	1,641 thousand barrels	1.8%	Feb-25	find more
Natural Gas in Underground Storage	599,933 million cu ft	9.6%	Feb-25	find more
Petroleum Stocks at Electric Power Producers	157 thousand barrels	0.8%	Feb-25	find more
Coal Stocks at Electric Power Producers	2,054 thousand tons	1.9%	Feb-25	find more
Fueling Stations	**Michigan**	**Share of U.S.**	**Period**	
Motor Gasoline	3,539 stations	3.2%	2022	
Propane	87 stations	3.3%	Apr-25	
Electric Vehicle Charging Locations	1,606 stations	2.3%	Apr-25	
E85	247 stations	5.6%	Apr-25	
Biodiesel, Compressed Natural Gas, and Other Alternative Fuels	9 stations	0.2%	Apr-25	

Consumption & Expenditures

Summary	Michigan	U.S. Rank	Period	
Total Consumption	2,707 trillion Btu	10	2022	find more
Total Consumption per Capita	270 million Btu	28	2022	find more
Total Expenditures	$ 46,032 million	9	2022	find more
Total Expenditures per Capita	$ 4,588	41	2022	find more
by End-Use Sector	**Michigan**	**Share of U.S.**	**Period**	
Consumption				
» Residential	754 trillion Btu	3.9%	2022	find more
» Commercial	579 trillion Btu	3.5%	2022	find more
» Industrial	664 trillion Btu	2.1%	2022	find more
» Transportation	711 trillion Btu	2.6%	2022	find more
Expenditures				
» Residential	$ 11,064 million	3.3%	2022	find more

Consumption & Expenditures

» Commercial	$ 7,148 million	2.9%	2022	find more
» Industrial	$ 6,267 million	2.2%	2022	find more
» Transportation	$ 21,553 million	2.5%	2022	find more

by Source	Michigan	Share of U.S.	Period	
Consumption				
» Petroleum	163 million barrels	2.2%	2023	find more
» Natural Gas	1,048 billion cu ft	3.2%	2023	find more
» Coal	14,516 thousand short tons	3.4%	2023	find more
Expenditures				
» Petroleum	$ 21,905 million	2.4%	2023	find more
» Natural Gas	$ 7,382 million	3.7%	2023	find more
» Coal	$ 979 million	4.1%	2023	find more

Consumption for Electricity Generation	Michigan	Share of U.S.	Period	find more
Petroleum	13 thousand barrels	0.6%	Feb-25	find more
Natural Gas	25,619 million cu ft	2.7%	Feb-25	find more
Coal	1,558 thousand tons	4.4%	Feb-25	find more

Energy Source Used for Home Heating (share of households)	Michigan	U.S. Average	Period
Natural Gas	74.0 %	46.0 %	2023
Fuel Oil	0.8 %	3.7 %	2023
Electricity	12.7 %	41.7 %	2023
Propane	9.1 %	5.0 %	2023
Other/None	3.4 %	3.5 %	2023

Environment

Renewable Energy Capacity	Michigan	Share of U.S.	Period	find more
Total Renewable Energy Electricity Net Summer Capacity	5,826 MW	1.6%	Feb-25	
Ethanol Plant Nameplate Capacity	346 million gal/year	1.9%	2024	

Renewable Energy Production	Michigan	Share of U.S.	Period	find more

Environment				
Utility-Scale Hydroelectric Net Electricity Generation	101 thousand MWh	0.5%	Feb-25	
Utility-Scale Solar, Wind, and Geothermal Net Electricity Generation	1,004 thousand MWh	1.8%	Feb-25	
Utility-Scale Biomass Net Electricity Generation	169 thousand MWh	4.6%	Feb-25	
Small-Scale Solar Photovoltaic Generation	23 thousand MWh	0.4%	Feb-25	
Fuel Ethanol Production	7,903 thousand barrels	2.2%	2022	
Renewable Energy Consumption	**Michigan**	**U.S. Rank**	**Period**	find more
Renewable Energy Consumption as a Share of State Total	7.4 %	28	2022	
Fuel Ethanol Consumption	10,287 thousand barrels	9	2022	
Total Emissions	**Michigan**	**Share of U.S.**	**Period**	find more
Carbon Dioxide	154.0 million metric tons	3.1%	2022	
Electric Power Industry Emissions	**Michigan**	**Share of U.S.**	**Period**	find more
Carbon Dioxide	50,018 thousand metric tons	3.3%	2023	
Sulfur Dioxide	31 thousand metric tons	3.7%	2023	
Nitrogen Oxide	43 thousand metric tons	3.8%	2023	

Analysis

Last Updated: October 17, 2024

Overview

Known as the Great Lakes State, Michigan's shores touch and include portions of four of the five Great Lakes.[1] The northern ends of two Great Lakes—Lake Michigan and Lake Huron—divide Michigan into the Upper and Lower Peninsulas. The northern shore of the Upper Peninsula is bordered by Lake Superior and a small portion of the southeastern shore of the Lower Peninsula touches Lake Erie.[2,3] The state‘s geologic history includes ancient broad shallow seas in a basin that was centered in Michigan's Lower Peninsula.[4] That basin was ringed by reefs that, now deeply buried, contain most of the state's crude oil and natural gas reserves.[5] In addition to Michigan's natural gas and crude oil, the state has many renewable energy resources. Winds that sweep across the Great Lakes provide the state with substantial offshore wind energy resources and moderate onshore ones.[6] Forests cover more than half of the state's land area and many cities and large towns provide municipal solid waste and landfill gas, giving Michigan considerable biomass resources.[7,8] Dams on the state's rivers generate hydroelectric power, despite the generally level terrain.[9] Most of those dams, including all of the largest ones, are in the Lower Peninsula, where Michigan's largest and longest rivers are located.[10,11]

Most of Michigan's population and all of the major cities, manufacturing industries, commercial agriculture, crude oil production, and natural gas production are located in the state's Lower Peninsula.[12,13] The Upper Peninsula is lightly populated, heavily forested, and contains valuable iron and copper deposits.[14,15,16] With 40,000 square miles of the Great Lakes and thousands of smaller inland lakes and ponds within Michigan's borders, the state's total area is more than two-fifths water—the largest land-to-water ratio among all states.[17,18] As a result, Michigan has one of the longest shorelines in the United States. Vessels that move through the Great Lakes-Saint Lawrence Seaway deliver coal and refined petroleum products at several of the state's Great Lakes ports.[19,20,21]

Michigan ranks 10th among the states in total energy use.

Michigan consumes almost five times more energy than it produces and ranks 10th among the states in both population and total energy consumption.[22,23,24] Although the Great Lakes moderate Michigan's temperatures, extremes occur in the interior of the Lower Peninsula. However, snowfalls are greatest on the Upper Peninsula and along the Lake Michigan shoreline of the Lower Peninsula.[25] In part because of its cold winters, Michigan is among the top 10 states in per capita residential energy use, but the state's total energy use per capita is below the U.S. average.[26] The residential sector is the leading energy-consuming sector, accounting for 28% of the state's total energy use, followed closely by the transportation sector at 26%, the industrial sector at 25%, and the commercial sector at 21%.[27] Detroit is known as Motor City, and Michigan employs the largest number of workers in the motor vehicles and parts manufacturing sectors in the nation.[28,29] This sector accounts for nearly two-fifths of the state's manufacturing GDP. Other important contributors to the state's GDP include the manufacture of machinery, fabricated metal products, chemicals, food and beverage products, and plastics.[30] Michigan does not have any significant critical mineral deposits, but is a major producer of cement, construction sand, and gravel.[31]

Natural gas

The Antrim Shale formation sweeps along a narrow arc in the northern portion of the Lower Peninsula and contains most of Michigan's natural gas reserves, and the state holds about 0.2% of U.S. total proved reserves.[32,33,34] Michigan's natural gas production has declined from its 1997 peak of nearly 312 billion cubic feet to 68 billion cubic feet in 2023, making up 0.2% of total U.S. production.[35,36]

Several interstate pipelines cross Michigan, as well as five U.S.-Canadian natural gas pipeline border crossings, but the state does not have any natural gas market hubs.[37] Natural gas enters Michigan from Ohio, Wisconsin, and Indiana. While some natural gas also arrives by pipeline from Canada, the bulk of the natural gas flowing across the border goes to Canada, most of it at St. Clair, located northeast of Detroit. Smaller volumes of natural gas also intermittently enter Canada at the Detroit, Sault St. Marie, and Marysville border crossings.[38,39,40] More natural gas enters Michigan than is consumed in the state, and most of the excess is exported to Canada.[41,42]

Michigan has the largest underground natural gas storage capacity in the nation.

Some of the natural gas that Michigan receives or produces is injected into underground natural gas storage fields. Michigan has the largest underground natural gas storage capacity in the nation at nearly 1.1 trillion cubic feet, which is almost one-eighth of the U.S. total. The state has 44 natural gas storage fields, the second-largest number after Pennsylvania.[43,44] During high demand periods, typically between November and April, natural gas is withdrawn from storage to meet increased demand for space heating. Much smaller volumes of natural gas are withdrawn from storage in the summer months when natural gas-fueled power generation increases to meet cooling demand.[45,46]

In 2023, Michigan's total natural gas consumption was 15 times greater than the state's natural gas production.[47,48] The electric power sector became the largest consumer of natural gas in the state in 2023, surpassing the residential sector for the first time and making up two-fifths of total natural gas use. The residential

sector, where almost 8 out of 10 Michigan households use natural gas as their primary source for home heating, accounted for about three-tenths of the state's natural gas consumption.[49,50] Michigan routinely ranks among the top 5 states in residential use of natural gas and in the top 10 for total natural gas consumption.[51,52] The commercial and the industrial sectors each account for about 16% of the state's natural gas consumption.[53]

Petroleum

Michigan's crude oil reserves and production are modest. The state's crude oil reserves and production each account for 0.1% of the nation's total.[54,55] Commercial quantities of crude oil were first found in Michigan in 1925.[56] The state's oil production substantially increased in the 1970s when oil was produced from the deeply buried reefs that ringed the Michigan Basin millions of years ago. Those reefs accounted for 29 million of the 35 million barrels of crude oil recovered in Michigan's peak production year of 1979.[57,58,59] Since then, Michigan's crude oil output has generally declined and was about 4.8 million barrels in 2023.[60]

Michigan has one crude oil refinery, located near Detroit. It can process about 140,000 barrels per calendar day of light sweet and heavy sour crude oils into gasoline, asphalt, propane, and other petroleum products.[61,62] Crude oil produced from wells in western Canada enters Michigan by pipelines through Wisconsin and Indiana. Crude oil produced in western Michigan is delivered by an intrastate pipeline to Lewiston, Michigan, where it is added into the Enbridge pipeline system that enters the state through northern Wisconsin. The Enbridge pipeline delivers crude oil to a Canadian refinery in Ontario and also has a branch that enters the state from Indiana and delivers crude oil to Michigan on its way to Ontario.[63,64,65] Michigan's governor revoked the pipeline's permit in May 2021 because of safety concerns about a potential leak where an underwater section of the pipeline crosses the Mackinac Strait between the state's Upper and Lower Peninsulas. Enbridge has refused to shut down the pipeline and the legal dispute remains. There have been discussions around building a tunnel to house the pipeline.[66,67,68] The Mid-Valley Pipeline, another crude oil pipeline that originates in the U.S. Gulf Coast states, enters Michigan through Ohio.[69] Port Huron on the Lower Peninsula receives additional crude oil imports from Canada.[70] Much of the crude oil that enters Michigan exits into Canada at a border crossing between Marysville, Michigan, and Sarnia, Ontario.[71]

Petroleum product pipelines bring refined products from the Chicago, Illinois, area to the southwest and from the Toledo, Ohio, area to the southeast of Michigan in the Lower Peninsula. The Upper Peninsula has no petroleum product pipelines, and trucks transport most petroleum products from terminals in Wisconsin.[72,73] The Lower Peninsula port cities of Port Huron and Detroit receive almost all the state's petroleum product imports from Canada. Some Canadian petroleum products also arrive at the Sault St. Marie port on the Upper Peninsula.[74]

Michigan has the largest residential sector consumption of hydrocarbon gas liquids, such as propane, in the nation.

Michigan ranks 11th among the states in total petroleum consumption. Four-fifths of the state's petroleum use is in the transportation sector, and motor gasoline accounts for 62% of that transportation petroleum consumption.[75,76] Federal regulations allow conventional motor gasoline without ethanol to be sold in most of the state year-round. However, to reduce emissions that contribute to ground-level ozone, eight southeastern Michigan counties around Detroit regulate the vapor pressure of motor gasoline sold during the summer.[77,78] The industrial sector accounts for one-tenth of the state's petroleum use. Although the residential sector accounts for only about 6% of the state's petroleum consumption, Michigan is among the top five states in residential sector petroleum consumption.[79] About 1 in 10 Michigan households heat with petroleum products, mostly propane.[80,81] Total consumption of hydrocarbon gas liquids (HGLs), such as propane, is greater in Michigan than in all but seven other states, and the state has the largest residential sector HGL consumption in the nation.[82] The commercial sector accounts for most of the rest of the state's petroleum consumption. A small amount of petroleum is used intermittently for electricity generation.[83]

Electricity

In 2023, natural gas fueled the largest share of Michigan's electricity generation at 46%, followed by nuclear power at 23%, and coal at 19%. Up until 2020, coal had provided the largest share of the state's electricity net generation.[84] Coal-fired plants make up 3 of the 10 largest power plants by generating capacity in the state, including the largest, and 4 of the top 10 were natural-gas fired.[85] Since 2020, about 2,700 megawatts of coal-fired generating capacity have been retired and no new coal-fired facilities are planned. The state's most recent operating coal-fired generating unit came online in 1990.[86] Michigan's electricity net generation from natural gas is more than four times greater in the last decade.[87] Two new natural gas-fired power plants are expected to come online by 2025, adding 1,000 megawatts of generating capacity.[88]

Michigan's in-state electricity net generation from natural gas is more than four times greater in the last decade.

Typically, Michigan's nuclear power plants have supplied about 30% of in-state electricity, but the amount of electricity generated by nuclear power plants in Michigan has declined as plants have been decommissioned. The state's Big Rock Point nuclear power plant shut down in 1997 and the Palisades nuclear power plant closed in 2022.[89,90,91] However, the new owners of the Palisades nuclear power plant are seeking to restart the plant.[92] The state currently has two operating nuclear power plants, Fermi with one reactor and Donald C. Cook with two reactors.[93]

Wind energy accounts for a small but increasing share of Michigan's electricity generation and accounted for 7% of the state's total generation in 2023. This was a slight decline from 2022, due to below normal wind speeds, despite 337 megawatts of new wind power generating capacity that came online in 2023.[94,95,96] Biomass, solar energy, gases created as byproducts of industrial processes, petroleum coke, and hydroelectric power provided most of the rest of the state's net generation.[97] Most of Michigan's power plants are located in the Lower Peninsula, where electricity demand is greatest.[98]

In 2023, Michigan ranked 11th among the states in the amount of electricity generated. Because consumption was less than generation, Michigan sent its surplus electricity out of state via the regional grid.[99,100] The commercial sector is the state's largest electricity consumer, accounting for 37% of the state's total electricity sales, followed very closely by the residential sector, with 34%. The industrial sector accounts for 29% of power sales.[101] Residential electricity sales per capita are less than in three-fourths of the states and less than the national average.[102,103] Only about 1 in 8 Michigan households rely on electricity as their primary source of energy for home heating.[104]

Electricity net generation from utility-scale solar in Michigan increased by 53% in 2023.

In July 2024, Michigan had about 1,500 public electric vehicle charging locations.[105] The majority of charging stations are located on the Lower Peninsula around Detroit, Grand Rapids, Lansing, and Kalamazoo.[106] The Charge Up Michigan Program provides grants to private and public organizations to help expand the state's electric vehicle charging network.[107]

Renewable energy

Renewable energy provided 11% of Michigan's total in-state electricity net generation in 2023, most of it from wind. In 2013, wind energy surpassed hydropower and biomass and became Michigan's largest source for renewable generation. In 2023, wind energy supplied 64% of the state's renewable electricity and about 7% of Michigan's total net generation from all sources.[108] The state's strongest onshore winds are along its curving Lake Huron and Lake Michigan coastlines.[109,110] Michigan ranks 12th in the nation in wind generation capacity and 16th in actual generation from wind energy.[111] The state has 34 wind farms with a total generating capacity of nearly 3,800 megawatts.[112] Many of

Michigan's wind farms are located between Saginaw Bay and Lake Huron in the eastern part of the state's Lower Peninsula.[113]

In 2023, biomass provided 15% of Michigan's renewable electricity generation and about 2% of the state's total generation from all sources.[114] Michigan has 35 biomass power plants with a combined generating capacity of 490 megawatts. A municipal solid waste plant in the Detroit area is one of the largest on the Lower Peninsula. The biomass plants that are fueled with wood and wood waste are primarily in more heavily forested northern Michigan, including on the Upper Peninsula. Several biomass facilities generate electricity using methane recovered from landfills.[115,116] Additionally, the state has anaerobic digesters that convert animal and food waste into biogas (methane) that is used as fuel for electricity generation.[117,118,119] Michigan's forests also provide the feedstock for the state's three wood pellet manufacturing plants that have a combined production capacity of 173,000 tons of pellets per year.[120] Wood pellets are used as fuel for electricity generation and for space heating. Wood is used for space heating by 2% of households in Michigan.[121]

Michigan has about four dozen conventional hydroelectric dams that accounted for about 1% of the state's total generation from all sources in 2023. However, the state's largest hydroelectric facility by capacity is a pumped-storage plant on the shores of Lake Michigan on the Lower Peninsula.[122,123,124] Built in 1973, Michigan's Ludington pumped storage plant has a nameplate generating capacity of about 2,200 megawatts and is one of the ten largest pumped storage power plants in the world.[125,126] During periods of low power demand, which are usually at night, less costly electricity is used to pump water from a lower reservoir to an upper reservoir. Then, during periods when power demand and electricity prices are higher, the water is released from the upper reservoir and flows down through generating turbines on its way back to the lower reservoir, producing electricity. Although the plant uses more power than it generates, it supplies power in periods of peak demand when electricity prices are highest.[127]

Michigan produces and consumes biofuels. It has four fuel ethanol production plants, all located in the southern half of the Lower Peninsula.[128] Those plants have a combined capacity of about 350 million gallons each year and produced 330 million gallons of fuel ethanol in 2022.[129,130] Michigan is among the nation's top 10 fuel ethanol-consuming states and uses more than it produces. In 2022, the state consumed about 430 million gallons of fuel ethanol.[131] Michigan's two biodiesel plants are also located on the Lower Peninsula.[132] These plants can produce 16 million gallons of biodiesel fuel each year, less than the 28 million gallons consumed in the state annually.[133,134]

In 2023, utility-scale (1 megawatt or larger) solar installations generated 1% of Michigan's total in-state electricity. The state's first utility-scale solar power facility, the 1-megawatt Domino Farms Solar, came online in 2015. In 2023, electricity net generation from utility-scale solar in Michigan increased by 53%.[135] Eleven solar farms came online in 2023, adding nearly 270 megawatts of generation capacity, including the 100-megawatt Cereal City Solar Energy Center project. An additional 1,280 megawatts of solar power capacity are expected to be added in the state by 2025.[136,137] Customer-sited, small-scale (less than 1 megawatt) solar photovoltaic (PV) generating systems, most of which are on residential and business rooftops, provided 19% of the state's total solar power.[138]

Michigan enacted a renewable energy standard (RES) in 2008 that required the state's retail electricity providers, including investor-owned electric utilities, alternative retail suppliers, electric cooperatives, and municipal electric utilities, to have at least 10% of the electricity they sold be generated by renewable energy resources by 2015. The RES goal was met, and, in December 2016, the state's RES requirement increased to 15% of electricity sales by 2021.[139] In 2020, all of Michigan's electric providers met the 15% RES.[140] Acceptable renewable energy resources for generating electricity include solar power, biomass, wind, geothermal energy, municipal solid waste, landfill gas, existing hydroelectricity, and tidal, wave, and river currents. Utilities are allowed to use energy efficiency to meet a portion of their requirements. In 2023, Michigan expanded the RES requirements, with an aim to use 100% clean energy by 2040.[141]

Coal

Michigan has a small amount of economically recoverable coal reserves, but no active coal mines.[142] However, Michigan ports, including the Port of Detroit, handled 31% of all Great Lakes coal shipments in 2023.[143] The electric power sector uses 92% of the coal consumed in Michigan to generate electricity. The industrial and commercial sectors use the other 8% to produce coke for steelmaking and for electricity and heat.[144] Most of the coal consumed in Michigan comes by rail from the West, primarily from Wyoming and Montana. Small amounts of coal also arrive from nearby states, including West Virginia, Pennsylvania, Colorado, Kentucky, Virginia, Indiana, and Illinois.[145]

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Other Resources

Energy-Related Regions and Organizations

- Petroleum Administration for Defense District (PADD): 2

- Regional Transmission Organization (RTO) and Independent System Operator (ISO): Midcontinent Independent System Operator (MISO), PJM Interconnection (PJM)
- North American Electric Reliability Corporation (NERC) ERO Enterprise: Regional Entities: Midwest Reliability Organization (MRO), Reliability First Corporation (RFC)

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States:Electricity Transmission Lines - Ventyx, Velocity Suite;Grey Base:National

0 25 50 100 Miles

- Mask
- Surface Coal Mine
- Underground Coal Mine
- Biomass Power Plant
- Coal Power Plant
- Geothermal Power Plant
- Hydroelectric Power Plant
- Natural Gas Power Plant
- Nuclear Power Plant
- Other Power Plant
- Other Fossil Gases Power Plant
- Petroleum Power Plant
- Pumped Storage Power Plant
- Solar Power Plant
- Wind Power Plant
- Wood Power Plant
- Petroleum Refinery
- Strategic Petroleum Reserve

http://www.eia.gov/state/

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-9

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

Exhibit 53

Consumers News Release

A key regulatory decision today cleared the way for Consumers Energy to stop burning coal to generate electricity by 2025 — 15 years faster than previously planned — and provide reliable electricity for Michigan.

The Michigan Public Service Commission (MPSC) approved Consumers Energy's agreement with a diverse group of stakeholders on updates to its Clean Energy Plan, a 20-year blueprint to meet Michigan's energy needs while protecting the environment for future generations.

A broad coalition of supporters for the plan includes customer groups, environmental organizations, MPSC staff, energy industry representatives and the Michigan Attorney General.

Consumers Energy is one of the first utilities in the nation to go coal-free.

"This is a historic moment in Michigan's clean energy transformation journey," said Garrick Rochow, President and CEO of Consumers Energy. "The Clean Energy Plan is a sea change that positions our company as a national leader and empowers us to deliver reliable energy while protecting the planet for decades to come."

The updates to Consumers Energy's Clean Energy Plan — first approved in 2019 — include:

- **COAL PLANT RETIREMENTS BY 2025:** closes all three units at the J.H. Campbell coal plant in West Olive in 2025 in addition to two units at the D.E. Karn coal plant in 2023 (as per the 2018 Clean Energy Plan) and will be among the first utilities in the nation to go coal-free by 2025.

- **SYSTEM RELIABILITY:** ensures supply reliability through the purchase of the Covert Generating Station in Van Buren County, a natural gas-fired power plant. Additionally, we plan to purchase 700 megawatts of electric capacity — roughly the equivalent of a power plant — from a variety of sources through a one-time request for proposal (RFP).

- **RISE OF SOLAR:** continues the rapid transition to clean, renewable sources by adding nearly 8,000 megawatts (MW) of solar power by 2040 ensuring 90 percent of our capacity comes from clean sources. Learn more at ConsumersEnergy.com/MiSolar (https://www.consumersenergy.com/company/electric-generation/renewables/solar-generation/farmers)

- **BATTERY DEPLOYMENT**: accelerates energy storage with a total of 75 MW of energy storage by 2027, achieving 550 MW by 2040.

- **AFFORDABLE ENERGY:** creates price stability and helps customers save an estimated $600 million dollars through 2040 compared to the current plan. Consumers Energy would also continue its successful energy waste reduction programs that have saved customers nearly $5 billion since 2009. In addition, the company has committed to continue to fund utility bill assistance programs for low-income customers.

"Together, we've created the best Clean Energy Plan for Michigan," Rochow said. "We're building a dramatically different energy landscape in which customers won't have to choose between protecting the planet and their pocketbooks. We will do both while making sure our state has the reliable power it needs."

Consumers Energy, Michigan's largest energy provider, is the principal subsidiary of CMS Energy (NYSE: CMS), providing natural gas and/or electricity to 6.8 million of the state's 10 million residents in all 68 Lower Peninsula counties.

# # #

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-9

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

Exhibit 54

NARUC Coal Report



Recent Changes to U.S. Coal Plant Operations and Current Compensation Practices

National Association of Regulatory Utility Commissioners | January 2020

Phillip Graeter, Energy Ventures Analysis, Inc.

Seth Schwartz, Energy Ventures Analysis, Inc.

EXHIBIT 15: TYPICAL STARTUP AND CYCLING COSTS FOR A MEDIUM-SIZED COAL-FIRED POWER PLANT ($2019)[19]

Type of Start	Cost category	Cost estimates ($/MW)		
		Expected	Low	High
Hot Start (1–23 h offline)	Maintenance and capital	$ 128	$ 102	$ 162
	Forced outage	$ 60	$ 48	$ 76
	Start-up fuel	$ 20	$ 14	$ 30
	Auxiliary power	$ 11	$ 8	$ 13
	Efficiency loss from low and variable load operation	$ 5	$ 4	$ 8
	Water chemistry cost and support	$ 1	$ 1	$ 2
	Total cycling cost	**$ 225**	**$ 178**	**$ 291**
Warm Start (24 - 120 h offline)	Maintenance and capital	$ 137	$ 109	$ 170
	Forced outage	$ 65	$ 51	$ 80
	Start-up fuel	$ 43	$ 30	$ 57
	Auxiliary power	$ 23	$ 18	$ 28
	Efficiency loss from low and variable load operation	$ 6	$ 5	$ 9
	Water chemistry cost and support	$ 6	$ 4	$ 9
	Total cycling cost	**$ 277**	**$ 217**	**$ 351**
Cold Start (> 120 h offline)	Maintenance and capital	$ 205	$ 162	$ 255
	Forced outage	$ 96	$ 76	$ 120
	Start-up fuel	$ 64	$ 45	$ 24
	Auxiliary power	$ 29	$ 23	$ 36
	Efficiency loss from low and variable load operation	$ 6	$ 5	$ 10
	Water chemistry cost and support	$ 17	$ 13	$ 21
	Total cycling cost	**$ 417**	**$ 325**	**$ 465**
Load follow down to 36% of Capacity	Maintenance and capital	$ 20	$ 12	$ 31
	Forced outage	$ 9	$ 6	$ 15
	Efficiency loss from low and variable load operation	$ 1	$ 1	$ 2
	Mill cycle gas	$ 2	$ 19	$ 50
	Total cycling cost	**$ 32**	**$ 19**	**$ 50**

As shown in **Exhibit 15,** expected costs for cold starts can be almost double the startup cost for a hot start when the remaining temperature in the boiler and turbine system are still significantly higher. However, even hot starts can range from $89,000 to $145,500 per start for a 500 MW coal-fired EGU. These costs can also vary significantly between coal units based on differences in boiler size and design (subcritical vs. supercritical). The highest cost

19 Source: Lefton S A, Hilleman D (2011). *Make your plant ready for cycling operations.* http://www.powermag.com/make-your-plant-ready-for-cycling-operations/

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-9

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

Exhibit 55

IEA Flexibility Report

Increasing the flexibility of coal-fired power plants

Colin Henderson

September 2014

© IEA Clean Coal Centre

4 Increasing flexibility – turbine and water-steam systems

There is much that can be done to make these areas of a plant more durable, able to respond faster and suffer less efficiency losses. Examples are given in this chapter.

4.1 Reducing stresses during start-up

Start-up, especially from cold, places particularly large stresses on many parts of a coal-fired plant. The turbine is no exception in this regard. Very rapid temperature changes need to be kept to the minimum, while component designs can be adapted to suit. Lindsay and Dragoon (2010) have collected together data from published sources on start-up times for different plant conditions. They found that, generally, coal plants required approximately 12 hours to cold start, 4 hours to warm start, and 1 hour to hot start. There was considerable variation, and this was believed to stem from how hot, warm, and cold starts were defined, and whether those times were actually equipment-limited or not.

One of the requirements for flexibility in the turbine is that the very small clearances between stationary and moving components remain almost constant during output changes. This requires careful design, advanced sealing (*see also* Henderson, 2013) and measures for ensuring uniform thermal loading and applies especially during cold start-up operations (Quinkertz and others, 2008).

Turbine bypass systems are a necessity in plants designed for two-shift (on/off) and other flexible forms of operation. They allow all or part of the steam to bypass the HP turbine or LP turbine so that the rate of steam temperature change in the turbine can be managed as the boiler is starting up and shutting down. This allows thermal stresses in the turbine to be reduced (Lindsay and Dragoon, 2010). This is not to be confused with another type of bypass (HP stage bypass), that can be installed for frequency control in new plants and is described later.

The very high temperature and pressure conditions of USC systems necessitate use of thick-walled components so that they possess adequate strength. Unfortunately, this can limit the rate of temperature change consistent with reducing thermal fatigue to acceptable levels. In the turbine, one means used to counter this is steam cooling of the outer casing to keep its temperature 30–40°C lower than that of the inner casing at the corresponding position along the turbine during load changes. The steam for this is bled radially from points along the inner casing. The steam reduces temperature extremes in the outer casing and allows its thickness to be reduced. The result is that cold start-up time is reduced by almost 50% (Almstedt and others, 2007).

4.2 Load following using sliding pressure operation

While, traditionally, throttling has been used to vary output from a turbine while keeping the pressure constant (Lindsay and Dragoon, 2010), sliding pressure operation has become a commonly applied system in modern supercritical once-through systems (Henderson, 2004). A critical constraint on ramping operation is matching steam and turbine metal temperatures, and more rapid output changes can be achieved using sliding pressure. Sliding pressure also offers advantages over throttle control

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-9

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

Exhibit 56

Blumenstock 2021 Second Rebuttal Testimony

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of CONSUMERS ENERGY COMPANY for approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and other relief.

Case No. U-21090

Volume 10

_____/

CROSS-EXAMINATION (Settlement Agreement)

Proceedings held via Microsoft Teams in the above-entitled matter before Sally L. Wallace, Administrative Law Judge with MOAHR, for the Michigan Public Service Commission, Lansing, Michigan, on Friday, May 20, 2022, at 9:06 a.m.

APPEARANCES:

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On behalf of Michigan Attorney General

(Continued)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for Approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief.	))))))	Case No. U-21090

SECOND REBUTTAL TESTIMONY

OF

RICHARD T. BLUMENSTOCK

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2022

Q. Please state your name and business address.

A. My name is Richard T. Blumenstock, and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as Executive Director of Electric Supply.

Q. Are you the same Richard T. Blumenstock that submitted direct and rebuttal testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of your second rebuttal testimony?

A. My second rebuttal testimony will provide an overview of the Settlement Agreement filed in this matter on April 20, 2022 and explain how the Settlement Agreement represents the most reasonable and prudent means of meeting the Company's energy and capacity needs, pursuant to MCL 460.6t(8). In the contested settlement portion of this proceeding, direct testimony was filed by Michigan Public Service Commission ("Commission" or "MPSC") Staff ("Staff") witness Paul A. Proudfoot; Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board ("MNS-CUB") witness Douglas B. Jester; Environmental Law and Policy Center, Vote Solar, Ecology Center, Union of Concerned Scientists, Urban Core Collective (collectively the Clean Energy Organizations ("CEOs")) witness James Gignac; Energy Michigan, Inc. ("Energy Michigan") witness Alexander J. Zakem; Wolverine Power Supply Cooperative, Inc. ("Wolverine") witness Thomas King, Jr.; and Cadillac Renewable Energy, LLC, Genesee Power Partners Limited Partnership, Decker Energy-Grayling, LLC, Tondu Corporation,

National Energy of Lincoln, LLC, and National Energy of McBain, LLC (collectively the Biomass Merchant Plants ("BMPs")) witness Richard A. Polich. My second rebuttal testimony will respond to portions of the testimony filed by the aforementioned witnesses but will particularly focus on responding to the assertions raised by the parties contesting approval of the Settlement Agreement, namely, Energy Michigan, Wolverine, and the BMPs.

Q. Have you prepared any exhibits in conjunction with your second rebuttal testimony?

A. Yes. I am sponsoring Exhibit A-150 (RTB-5), the April 20, 2022 Settlement Agreement.

Q. Was this exhibit prepared by you or under your direction?

A. Yes.

I. THE SETTLEMENT AGREEMENT

Q. On page 1 of his contested settlement direct testimony, BMP witness Polich alleges that there are "inconsistencies, failures and risks presented by the proposed Settlement." Furthermore, on page 1 of his contested settlement direct testimony, Energy Michigan witness Zakem indicates that "Energy Michigan is objecting to the Settlement" and on page 9 of his testimony, Wolverine witness King recommends that the Settlement Agreement be rejected. Please describe the proposed Settlement Agreement which the BMPs, Energy Michigan, and Wolverine are contesting.

A. The Settlement Agreement, as provided in Exhibit A-150 (RTB-5), is the result of extensive negotiations and represents a compromise on the positions filed by the parties in this case. The Settlement Agreement proposes to completely resolve this matter and the signing parties have agreed that the resolution is in the public interest. Numerous other

parties have also agreed not to object to the Settlement Agreement. The Settlement Agreement also generally provides for the following:

- The approval of the Company's Proposed Course of Action ("PCA"), as modified by the Settlement Agreement, as the most reasonable and prudent means of meeting the Company's energy and capacity needs over the 5-year, 10-year, and 15-year time horizons. The Company will file its next Integrated Resource Plan ("IRP") consistent with the requirements of MCL 460.6t;
- The approval of the purchase of the New Covert Generating Facility ("Covert Plant") and of investments in, and the capacity value of, resources which the Company will commence within the next three years;
- The approval of a battery deployment program which will accelerate the deployment of batteries in the PCA through an additional 75 MW of batteries being added between 2024 and 2027;
- The retirement of the entire J.H. Campbell ("Campbell") coal plant in 2025, approximately 15 years sooner than planned, and accounting mechanisms to recover the unrecovered book balance and decommissioning costs of the Campbell Plant. D.E. Karn ("Karn") Units 3 and 4 will continue operating until 2031, consistent with the design lives of those units, and will continue to provide capacity and reliability for the Company and its customers as the PCA is implemented;
- A one-time solicitation which will seek to acquire: (i) up to 500 Zonal Resource Credits ("ZRCs") of capacity through power purchase agreements ("PPA") with dispatchable, nonintermittent generation and (ii) up to

200 ZRCs from unaffiliated third-party intermittent resources and dispatchable, nonintermittent clean capacity resources;

- Accounting approval to defer expenses related to the Campbell site severance and retention agreement. The Settlement Agreement also provides for community transition activities related to the Campbell and Karn sites;
- The extension of the annual competitive solicitation process used to acquire the supply-side resource technologies specified in the PCA and the 50%/50%, Company ownership to third-party ownership construct, as initially approved in Case No. U-20165, with certain modifications. Among other things, those modifications provide greater flexibility for the Company to pursue the most economic projects in each solicitation. Through the annual solicitation process the Company will continue the solar glidepath, as outlined in the PCA, which provides for the addition of approximately 8,000 MWs of solar resources by 2040;
- The extension of the Financial Compensation Mechanism ("FCM") approved in Case No. U-20165, with certain modifications to the new PPAs for which the FCM applies;
- The extension of the Company's Public Utility Regulatory Policies Act of 1978 ("PURPA") avoided cost construct, as approved in Case No. U-20165, with certain modifications which include modifications impacting eligibility for avoided cost rates and the Standard Offer Tariff and PPA;

- Ongoing Company donations, which will not be recovered from customers, to a low-income fund that provides bill assistance to Consumers Energy's electric customers; and
- Finally, the Settlement Agreement includes numerous actions that the Company must implement and items that the Company must evaluate and consider in the Company's next IRP. That includes modeling and analysis related to distributed resources and generation, emissions analysis, combined heat and power resource analysis, and new processes to implement in the Company's public outreach efforts.

Q. What parties to this matter signed the Settlement Agreement?

A. On April 20, 2022, Consumers Energy entered into the Settlement Agreement with the following parties: the Michigan Public Service Commission Staff, Michigan Environmental Council, National Resource Defense Council, Sierra Club, Michigan Attorney General Dana Nessel ("Attorney General"), Environmental Law and Policy Center, Vote Solar, Ecology Center, Union of Concerned Scientists, Urban Core Collective, Citizens Utility Board of Michigan, Hemlock Semiconductor Operations, LLC, Michigan Energy Innovation Business Council, Institute for Energy Innovation, Clean Grid Alliance, Michigan Electric Transmission Company, LLC, and Great Lakes Renewable Energy Association.

Q. What parties to this matter indicated that they do not object to the approval of the Settlement Agreement?

A. The following parties signed a statement of non-objection: Michigan Public Power Agency, Midland Cogeneration Venture, LP, Association of Businesses Advocating Tariff Equity, and Residential Customer Group.

Q. What positions did the remaining parties to the proceeding take with respect to the filing of the Settlement Agreement?

A. On May 3, 2022, Energy Michigan filed Objections to the Settlement Agreement. On May 4, 2022, the following parties filed Objections to the Settlement Agreement: the Mackinac Center for Public Policy, Wolverine, and the BMPs. Only Energy Michigan, Wolverine, and the BMPs have filed direct testimony in this contested case proceeding.

Q. On page 4 of his contested settlement direct testimony, Wolverine witness King alleges that the outcome of the Settlement Agreement "not the 'most reasonable and prudent plan to meet the utility's energy and capacity needs'" under MCL 460.6t. BMP witness Polich makes similar allegations on page 4 of his contested settlement direct testimony. Furthermore, on page 7 of his direct testimony supporting the Settlement Agreement, Staff witness Proudfoot asserts that the PCA, as modified in the Settlement Agreement, meets the statutory requirements of MCL 460.6t. Does the Settlement Agreement meet the statutory requirements of MCL 460.6t?

A. Yes. As discussed in more detail below, the Settlement Agreement should be approved by the Commission because it results in the most reasonable and prudent plan to meet the energy and capacity needs of the Company's customers.

Q. Please explain the requirements for approval of an IRP under MCL 460.6(t)?

A. As indicated in my direct testimony filed in this matter, Subsection (8) of MCL 460.6t requires the Commission to approve an IRP, if it determines the plan represents the most reasonable and prudent means of meeting the electric utility's energy and capacity needs. To make this determination, the Commission shall consider whether the plan appropriately balances all of the following factors:

i. Resource adequacy and capacity sufficient in quantity to serve anticipated peak electric load plus applicable Planning Reserve Margin Requirement ("PRMR") and Local Clearing Requirement ("LCR");

ii. Compliance with applicable state and federal environmental regulations;

iii. Competitive pricing;

iv. Reliability;

v. Commodity price risks;

vi. Diversity of generation supply; and

vii. Whether the proposed levels of peak load reduction and Energy Waste Reduction ("EWR") are reasonable and cost effective.

Q. Does the Settlement Agreement meet the requirements for approval of an IRP under MCL 460.6t?

A. Yes. One of the over-arching objectives in developing the IRP PCA, and the resulting Settlement Agreement, was to create the most reasonable and prudent means of meeting short- and long-term energy and capacity needs. In the Settlement Agreement, the intent and focus of the Company's original PCA were maintained, ensuring the Company's clean energy transition, as initially set forth in the Company's 2018 IRP. The PCA, as modified by the Settlement Agreement, will help lead a faster clean energy transformation by accelerating the Company's exit from coal-fired generation while increasing electric

reliability and providing resource adequacy for customers. The Settlement Agreement satisfies the planning objectives set forth by the Commission in Subsection (8) of MCL 460.6t.

Q. Please explain how the Settlement Agreement ensures resource adequacy and capacity that is sufficient in quantity to serve anticipated peak electric load plus applicable PRMR and LCR.

A. The PCA, as modified in the Settlement Agreement, has maintained a balance of resource additions and retirements—backfilling capacity lost to accelerated retirement with the addition of new baseload resources, expansion of demand-side resources, expansion of renewable resources, and deployment of battery storage resources. The Settlement Agreement continues the annual solicitation process which will procure the supply-side resource technologies specified in the PCA. The Settlement Agreement also provides for the purchase of the Covert Plant, which is a resource that will move into the Midcontinent Independent System Operator, Inc. ("MISO") Zone 7 from PJM Interconnection, LLC ("PJM"), the continued operation of Karn Units 3 and 4 (with retirement on or before May 31, 2031), consistent with the design lives of those units, and the one-time solicitation which will procure 700 Zonal Resource Credits ("ZRCs") of capacity and associated energy. The Settlement Agreement also provides for numerous mechanisms for the Company to procure capacity if it is needed, such as the flexibility to procure additional MWs in the annual solicitation process and the ability to make short-term capacity additions to address capacity shortfalls which cannot reasonably be addressed through the annual solicitation process. All of these items provided for in the Settlement Agreement

ensure resource adequacy and capacity that is sufficient in quantity to serve anticipated peak electric load plus applicable PRMR and LCR.

Q. Please explain how the Settlement Agreement ensures compliance with applicable state and federal environmental regulations.

A. The PCA, as modified in the Settlement Agreement, is in full compliance with all environmental regulations and mitigates future financial risks of potential environmental regulation on fossil fuel generation. The PCA also specifies retirement of Campbell Units 1, 2, and 3 by 2025, approximately 15 years sooner than planned, aggressively reduces waste, and continues to increase solar generation; all consistent with the Company's evolved Clean Energy and decarbonization goals. As indicated in my direct testimony in this case, the Company's Clean Energy Goal calls for reducing carbon emissions to achieve net zero by 2040 and exit coal by 2025. The Settlement Agreement keeps the Company on a path to achieving these goals and also would put Michigan on track to achieve the Governor's Michigan Healthy Climate Plan which calls for reducing carbon emissions by 52% by 2030 and ending coal-fired generation. This is further confirmed in the testimony of CEO witness Gignac and MNS-CUB witness Jester as filed in this contested settlement proceeding. See CEO witness Gignac's Testimony in Support of Settlement Agreement, page 3; MNS-CUB witness Jester's Testimony in Support of Settlement Agreement, pages 6-9.

Q. Please explain how the Settlement Agreement ensures competitive pricing.

A. The PCA, as modified in the Settlement Agreement, provides competitive pricing in numerous ways. First, the Settlement Agreement PCA provides for customer savings of nearly $600 million. These savings are achieved through accelerated retirement of existing

assets, acquisition of the Covert Plant, and continuing the strategy of modular deployment of new generation and demand-side sources. The plan provides for balancing retirements and additions along a glide path that provides flexibility to adjust plans in the future should lower-cost technologies become available. The resources identified in the PCA are also supported by the Company's extensive modeling performed in this case which identified least-cost resources. The Company also agrees with MNS-CUB witness Jester that "[e]xtensive modeling conducted by Consumers and by MNS-CUB in this case demonstrated that retiring Campbell in 2025 is economic for customers." MNS-CUB witness Jester's Testimony in Support of Settlement Agreement, page 6. Additionally, competitively bidding new supply-side generation in the one-time solicitation and annual solicitation processes provides an opportunity to identify and take advantage of the best implementation opportunities while limiting cost to customers.

Q. Please explain how the Settlement Agreement ensures reliability.

A. The PCA, as modified in the Settlement Agreement, allows the Company to maintain sufficient capacity resources to meet the expected PRMR. Additionally, the Company plans to secure resources within the lower peninsula of Michigan that will be transferred to MISO Zone 7 through the purchase of the Covert Plant and are located in MISO Zone 7 through the solicitations provided for in the Settlement Agreement, ensuring that the LCR is also met. MNS-CUB witness Jester correctly noted in his testimony filed in this contested settlement proceeding that the acquisition of the Covert Plant supports reliability because "Covert will add 1,114 Zonal Resource Credits or ZRCs to MISO Zone 7." See MNS-CUB witness Jester's Testimony in Support of Settlement Agreement, page 10.

Further, the PCA, as modified in the Settlement Agreement, provides electric reliability assurance consistent with the PCA as filed. The Company provided a capacity sufficiency analysis and stochastic risk assessment that highlighted the electric reliability benefits of the PCA and the PCA, as modified by the Settlement Agreement, is expected to provide similar reliability benefits. Finally, the flexibility of phased-in modular resources provides the Company adequate time to mitigate cost, assess reliability within the reconfigured portfolio, and to modify as necessary.

Q. Please explain how the Settlement Agreement addresses commodity price risks.

A. The PCA, as modified in the Settlement Agreement, provides for a diverse portfolio of pumped storage and hydro generation, gas generation, wind and solar generation, energy efficiency, demand response, emerging technologies such as grid modernization and battery storage, and PPAs with numerous technology types. This represents a balanced and modular supply plan which provides flexibility to adjust to changes in fuel costs, technology cost, electric demand, or the business environment and insulates the Company and its customers from commodity price risks. The Settlement Agreement also continues the Clean Energy Plan which provides for a modular and scalable supply portfolio which will provide further opportunities for the utilization of diverse supply resources and protects against high customer rates.

Q. Please explain how the Settlement Agreement ensures diversity of generation supply.

A. As explained above, the PCA, as modified in the Settlement Agreement, provides for a diverse portfolio of pumped storage and hydro generation, gas generation, wind and solar generation, energy efficiency, demand response, emerging technologies such as grid modernization and battery storage, and PPAs with numerous technology types. In addition,

the Company intends to keep its gas- and oil-fired peaking resources (i.e. Karn Units 3 and 4) operational, to ensure customer reliability needs are met. This blend of resources provides a significant diversity of generation supply. The modular nature in which many of these resources are added to the generation supply ensures future agility in response to changing technology or market conditions.

Q. Please explain whether the proposed levels of peak load reduction (Demand Response ("DR"), Conservation Voltage Reduction ("CVR"), and EWR), in the Settlement Agreement are reasonable and cost effective.

A. The proposed levels of peak load reduction (DR, CVR, and EWR) in the PCA, as modified in the Settlement Agreement, are aligned with the Company's testimony in this proceeding, the DR and EWR potential studies conducted in support of the Company's IRP and are reasonable and cost effective. The implementation of demand-side resources ensures consistent and effective marketing can be developed and deployed. Also, as detailed in the Settlement Agreement, the Company will continue reporting any changes to the approved demand-side projects, thereby ensuring that cost will be continuously assessed as the Company's implementation of its PCA moves forward.

Q. Please explain other benefits of the Settlement Agreement that the Commission should consider.

A. As explained above, the Settlement Agreement continues the annual solicitation process for procuring capacity through competitive bids originally approved in Case No. U-20165, with certain modifications, and provides for a one-time solicitation process for procuring 700 ZRCs of capacity and energy. These solicitations provide an orderly process for the acquisition of capacity and energy and provide customers with the benefit of competitively

priced energy and capacity. Furthermore, the modifications to the annual solicitation process provide the Company with greater ability to pursue the most economic projects in each solicitation. The Settlement Agreement also continues the Company's PURPA avoided cost construct, as approved in Case No. U-20165, with certain modifications. Among other things, those modifications will provide Qualifying Facilities ("QFs"), which the Company has obligation to purchase from under PURPA, with greater access to the Standard Offer PPA.

The Settlement Agreement provides that approximately 50% of the new capacity that the Company intends to procure through the PCA in each annual solicitation will be from PPAs and other third-party agreements that do not result in Company ownership and approximately 50% will be owned by the Company, as acquired through a competitive bidding process. This approach, which is similar to what was approved in Case No. U-20165, provides opportunities for third-party resources and resources which will ultimately be owned by the Company to participate in the annual solicitation process.

The Settlement Agreement also provides for an extension of the FCM approved in Case No. U-20165, and FCM cap, on PPA payments, which appropriately incentivizes the Company to proceed with the PCA instead of the traditional utility regulatory model which encourages utilities to build owned assets and discourages pursuit of PPAs due to imputed debt concerns. This important incentive was correctly acknowledged by MNS-CUB witness Jester in his testimony filed in this contested settlement proceeding. See, MNS-CUB witness Jester's Testimony in Support of Settlement Agreement, page 17. The continued approval of such compensation is critical to creating a stable, sustainable

regulatory and financial model that drives utilization of PPAs that benefit the Company's customers and the state of Michigan.

The Settlement Agreement also provides for the approval of accounting mechanisms to recover the unrecovered book balance and decommissioning costs of the Campbell Plant. The recovery of these costs in a manner which helps ensure the financial health of the utility, as provided for in the Settlement Agreement, is critical to the Company's ability to retire the Campbell Plant in 2025.

The Settlement Agreement further provides for the accelerated deployment of battery storage in advance of when these resources were planned to be deployed in the originally proposed PCA. The battery deployment program will accelerate the deployment of battery storage in the PCA through an additional 75 MW of batteries being added between 2024 and 2027 and the one-time solicitation will provide an additional opportunity for battery storage resources to be procured and deployed.

The Settlement Agreement provides that the Company will donate $5 million in 2022 to a low-income fund that provides bill assistance to Consumers Energy's electric customers and will donate $2 million annually to the same low-income fund in future years. These donations will not be recovered in rates and Consumers Energy will consult with the Attorney General and Staff on the low-income fund receiving the donations.

The collaboration agreed to as part of the Settlement Agreement is also extensive and important to note. This includes: (i) stakeholder engagement prior to the initiation of the battery deployment program; (ii) stakeholder engagement related to the one-time solicitation process; (iii) consultation with organizations and community members regarding the Campbell Plant community transition plan; (iv) consultation with the settling

parties regarding the bid evaluation criteria in the annual solicitation process; (v) stakeholder outreach to develop a simplified agreement, tariff-based program, or other mechanism which will allow QFs 150 kWac and below to receive full avoided cost rates; and (vi) stakeholder outreach related to a distributed generation as a resource modeling approach. The Settlement Agreement also provides for greater public accessibility during the public outreach process implemented by the Company prior to its next IRP.

Q. Does the Company's evidence, as bound into the record in this matter, support the Settlement Agreement?

A. Yes. The Company's direct testimony, rebuttal testimony, second rebuttal testimony, and exhibits support approval of the PCA and the Settlement Agreement. The testimony and exhibits of many other parties, including that of Staff, also support the compromise positions reached in the Settlement Agreement. Therefore, the evidence submitted in this matter establishes that the Settlement Agreement is based on substantial record evidence.

II. RESPONSE TO ENERGY MICHIGAN WITNESS ZAKEM

Q. Beginning on page 1 of his contested settlement direct testimony, Energy Michigan witness Zakem indicates that Energy Michigan objects to the Settlement Agreement because of "impacts on resource adequacy and impacts on the competitive markets." Do you agree with Mr. Zakem's concerns?

A. No. Company witness Thomas P. Clark addresses and refutes Mr. Zakem's alleged "impacts on resource adequacy and impacts on the competitive markets." However, there are other foundational flaws in Mr. Zakem's arguments which the Commission should consider in rejecting Energy Michigan's objections. In this contested settlement proceeding, Energy Michigan is continuing to rely on its direct testimony as previously submitted in this case before the Settlement Agreement was reached. See Energy Michigan

witness Zakem's Contested Settlement Direct, page 2. The problem with that approach is that Mr. Zakem's direct testimony was focused on the Company's purchase of the Dearborn Industrial Generation ("DIG"), the Kalamazoo River Generating Station ("Kalamazoo"), and the Livingston Generating Station ("Livingston") plants (see 8 TR 3171-3178) and the Settlement Agreement no longer provides for the purchase of those plants in the manner initially proposed by the Company. Mr. Zakem has also made no adjustment to his initial position to account for the fact that the Settlement Agreement continues operation of Karn Units 3 and 4 until 2031, as opposed to 2023, as initially proposed by the Company. Therefore, while Mr. Zakem's assessment of the Company's PCA was incorrect from the outset, it is now also incorrect because it no longer accurately describes the elements of the PCA, as modified by the Settlement Agreement.

In an attempt to rehabilitate his direct testimony, Mr. Zakem claims that the one-time solicitation provided for in the Settlement Agreement may "already being counted toward MISO Zone 7's resource adequacy requirements" but this position is entirely speculative. Furthermore, for the reasons discussed by Company witness Clark, Mr. Zakem has failed to establish that the Company's procurement of resources already located in MISO Zone 7 is a valid reason to reject the Settlement Agreement.

III. RESPONSE TO WOLVERINE WITNESS KING

Q. What are the arguments discussed in the contested settlement direct testimony of Wolverine witness King that you will address in your second rebuttal testimony?

A. Mr. King's arguments focus on purported reliability issues that he claims are at risk in the Settlement Agreement. Mr. King attempts to suggest that the Company's PCA, as modified by the Settlement Agreement, leaves the Company capacity deficient in 2025 and recommends that "[t]he Commission should simply adjust the timeline for retirement of

Campbell 3." See Wolverine witness King's Contested Settlement Direct, page 9. Mr. King's claimed Company capacity deficiency is plainly incorrect. Wolverine has also failed to establish any reliability risks related to the PCA, as modified by the Settlement Agreement.

My second rebuttal testimony will discuss the fatal flaws of the calculations presented in Mr. King's exhibit regarding the Settlement Agreement capacity position. Company witness Clark will address Mr. King's incorrect assessment of reliability risks including: the Company's December 2021 capacity demonstration filing, Case No. U-21099, underlying load forecast assumptions, and solar capacity accreditation. See Wolverine witness King's Contested Settlement Direct, pages 4-9. Company witness Clark will also address other areas where Wolverine has incorrectly conveyed the reliability risks of the Settlement Agreement.

Finally, the Commission should reject Mr. King request to adjust the timeline for retirement of Campbell Unit 3, as proposed in the Settlement Agreement. As explained in response to the BMPs, the terms of the Settlement Agreement do not permit modification to the Settlement Agreement. Furthermore, proposed modifications to the Settlement Agreement or alternative settlement proposals are beyond the scope of this contested settlement proceeding.

Q. What are Mr. King's arguments regarding the Settlement Agreement capacity position?

A. Beginning on page 3 of his contested settlement direct testimony, Mr. King states that "Consumers will likely be capacity negative in 2025," and later discusses the basis for that opinion. However, Mr. King's arguments are philosophically and technically flawed.

Q. What are the flaws of Mr. King's arguments regarding the Settlement Agreement capacity position?

A. There are two initial flaws in Mr. King's representation of the Company's capacity position which undermine the credibility of Mr. King's position. First, the magnitude of Mr. King's (erroneously) calculated shortfall is insignificant (28 ZRC, as shown in Exhibit WPSC-7) for 2025. On page 3 of his contested settlement direct testimony, Mr. King references his own Exhibit WPSC-6, which states

> *The 2020-21 OMS-MISO survey projected a small surplus for planning year 2022-23, which was eroded by an increased load forecast, less capacity entering the auction as result of retirements, and the decreased accredited capacity of new resources.*

MISO's above statement is indicative of the fact that a small magnitude surplus *or* shortfall can shift over a relatively short period of time. This is why the Company implements a strategy of maintaining approximately 200 ZRCs of capacity surplus.

The second issue with Mr. King's argument is that he relies on the exclusion of capacity acquired through the one-time solicitation included in this Settlement Agreement. His claim that the Company could be capacity negative in 2025 would assume the Company is wholly unsuccessful in its one-time solicitation – that 0 ZRC of capacity are acquired through a Request for Proposals soliciting up to 700 ZRCs. That is highly unlikely. Properly including the addition of up to 700 ZRCs, even Mr. King's own exhibit shows capacity sufficiency in year 2025 above the Company's strategic surplus amount of 200 ZRC.

Q. What are the technical flaws of Mr. King's arguments regarding the Settlement Agreement capacity position?

A. Exhibit WPSC-7 is offered as evidence to support an alleged 28 ZRC capacity shortfall (disregarding any capacity acquired through a solicitation looking for up to 700 ZRCs) in 2025. The mechanics in the calculation supporting the shortfall for 2025 are incorrect.

The calculation is presented in Exhibit WPSC-7. The first column of data, "**Settlement 2022/23**" is taken directly from the Company's detailed calculations of capacity position. The value shown on the row labeled as "Surplus/Deficient" is the correct ZRC surplus level projected and presented in Figure 6 of my direct testimony in the initial filing of this case.

Mr. King's next step is to compare the filed capacity position of the 2021 IRP to the filed capacity position presented in the Company's December 2021 capacity demonstration filing, Case No. U-21099. This is summarized in Exhibit WPSC-7 in the column labeled as "**Cap Dem 2022/23**." Mr. King has generally populated this column with appropriate values from Case No. U-21099. He has then created an "Equalization Adjustment Factor," which accounts for the difference in final capacity position between the Capacity Demonstration and the IRP. Although Mr. King's testimony is not well-supportive of the calculation, the Company is able to confirm the accuracy of this value for planning year 2022/2023.

Next, in Exhibit WPSC-7, Mr. King calculates a planning year 2025 capacity position in the column labeled as "**Settlement 2025/26**." This is consistent with Figure 6 of my direct testimony, with modifications to (i) remove the DIG, Kalamazoo, and Livingston plant capacity; (ii) extend the capacity for Karn Units 3 and 4; and (iii) add

capacity that will be acquired through the one-time solicitation. I take no issue with these modifications; however, Mr. King has failed to add capacity provided by the battery deployment program, which would contribute approximately 14 ZRCs by 2025.

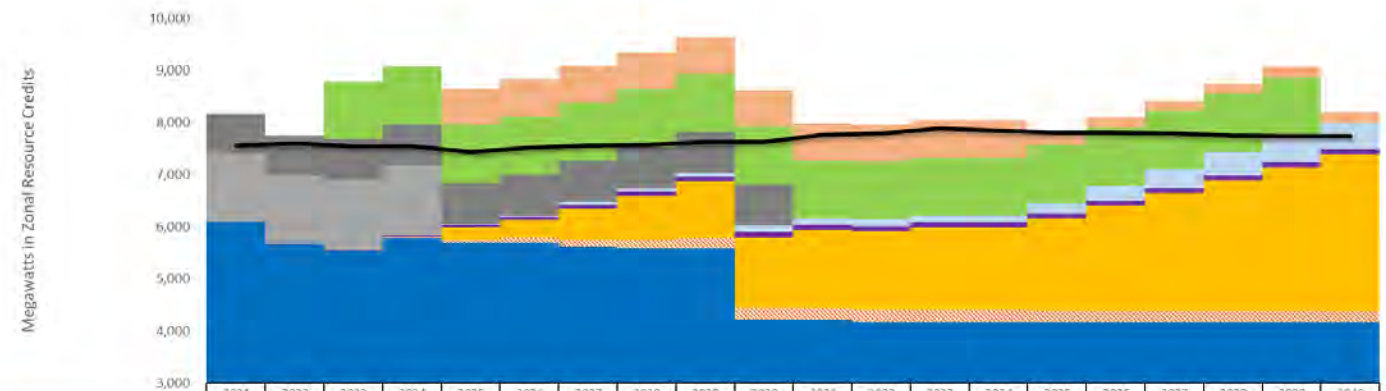
The flaw in the analysis, however, occurs in the final column of Exhibit WPSC-7 labeled as "**Cap Dem 2025/26**." While the lines of data through the row labeled as "PRMR" are generally accurate (though again, Mr. King fails to include 14 ZRC that will be provided by the battery deployment program), attention must be brought to the row "Equalization Adjustment Factor." While Mr. King referenced this row on page 4, line 21, of his testimony, he offers little in the way of explanation for it. While this section of my testimony addresses the Company's general acceptance of the -343 ZRC value *for planning year 2022/2023*, Mr. King's testimony fails to explain how this value is calculated or the appropriate use of this value. In fact, Mr. King offers no explanation whatsoever in his application of the -343 ZRC value to the final column of Exhibit WPSC-7, which is an accounting of *planning year 2025/2026* capacity and demand, not 2022/2023. An appropriate re-calculation of the "Equalization Adjustment Factor" for planning year 2025/26 would be required, but Mr. King failed to do so. In fact, Mr. King's "Equalization Adjustment Factors" are only included in his exhibit to calculate the capacity position filed in the capacity demonstration. That value is readily available in Case No. U-21099, Exhibit 2 of 11, line 35, column (d), shown to be a +25 ZRC surplus[1]. Application of a correct "Equalization Adjustment Factor" as well as inclusion of 14 ZRCs of battery deployment capacity would result in a positive "Surplus/Deficit" value of +39 ZRCs, a capacity surplus, not a -28 ZRC capacity shortfall, as mis-calculated in Exhibit WPSC-7.

[1] This is consistent with Mr. King's column "Cap Dem 2022/23," which is also presented in Case No. U-21099, Exhibit 2 of 11, line 33, column (a).

Combined with up to +700 ZRCs of capacity acquired through the one-time solicitation, it is abundantly clear that Mr. King's statement that the Company could be capacity negative in 2025 is disproven.

The prior discussion reconciled Mr. King's calculated capacity position from the Company's December 2021 capacity demonstration, Case No. U-21099. Figure 1, below, presents the capacity position of the PCA, as modified by the Settlement Agreement. While Figure 1 indicates a very small capacity shortfall in 2035 (34 ZRCs), the Company will have sufficient time between now and 2035 to address that shortfall. There are also numerous mechanisms provided for in the Settlement Agreement which will allow the Company to address that projected shortfall long before it may happen.

Figure 1: Proposed Course of Action, as Modified by the Settlement Agreement



	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
One-time Solicitation					700	700	700	700	700	700	700	700	700	700	200	200	200	200	200	200
Covert	-	-	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	
Karn 3&4	767	769	787	785	784	787	789	789	789	789	-	-	-	-	-	-	-	-	-	-
Campbell 1-3	1,313	1,318	1,144	1,346	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
New Storage	-	-	-	5	14	33	71	71	71	126	127	128	130	131	208	286	364	441	514	507
New Demand Response	-	-	12	25	37	49	62	74	87	99	99	99	99	99	99	99	99	99	99	99
New Solar					250	352	602	852	1,102	1,352	1,488	1,513	1,591	1,591	1,759	2,009	2,259	2,509	2,759	3,009
New Energy Waste Reduction	-	-	-	20	57	91	123	157	187	216	231	232	229	229	225	222	220	218	215	213
Current Existing Portfolio	6,095	5,667	5,533	5,781	5,694	5,694	5,624	5,589	5,589	4,227	4,209	4,168	4,168	4,168	4,168	4,168	4,168	4,168	4,168	4,168
PRMR	7,558	7,600	7,542	7,553	7,435	7,516	7,558	7,575	7,627	7,625	7,770	7,796	7,883	7,844	7,807	7,804	7,785	7,745	7,734	7,759
Capacity position	617	154	1,249	1,522	1,215	1,304	1,528	1,771	2,012	998	209	158	148	188	(34)	294	639	1,005	1,336	456

IV. RESPONSE TO BMP WITNESS POLICH, P.E.

A. CONSIDERATION OF BIOMASS PLANTS

Q. Beginning on page 2 of his contested settlement proceeding direct testimony, BMP witness Polich offers eight objections to the Settlement Agreement. Do you agree with Mr. Polich's objections?

A. No. I will address Mr. Polich's arguments in more detail below; however, the BMPs' foundational position in this case has not changed in this contested settlement proceeding from what the BMPs initially argued prior to settlement. The BMPs are continuing to claim that the Company did not appropriately consider biomass plants in this IRP and continue to push for PPA extensions for the individual BMP plants. See BMP witness Polich's Contested Settlement Direct Testimony, pages 4-6. The BMPs' positions are unreasonable, not supported in the record, and fail to provide a basis to reject the proposed Settlement Agreement.

As explained by Company witness Keith G. Troyer in his rebuttal testimony, the Company is not under any obligation to enter new PPAs with the BMPs or extend the BMPs' existing contracts. Each of the BMPs are above the Company's must-purchase obligation MW threshold under PURPA and therefore, the Company is not required under PURPA to continue purchasing from the BMPs once the current PPAs for those plants expire. Furthermore, while the BMPs concede that the Hillman Plant will retire in 2022 (see BMP witness Polich's Contested Settlement Direct, page 5), the BMPs fail to acknowledge that the prior owners of the National Energy of Lincoln and McBain plants contractually agreed to decommission those plants when their current PPAs expire. This means that the only BMPs which could conceivably enter a new PPA or PPA extension with the Company are TES Filer City Station (PPA expires in 2025), Grayling Generating

Station (PPA expires in 2027), Cadillac Renewable Energy (PPA expires in 2028), and Genesee Power Station (PPA expires in December 2030).

Moreover, the Company did consider biomass plants in the development of the IRP. The Company considered biomass plants as it began its modeling process, but due to the fact that those resources were not viable options on an economic or cost basis, biomass plants did not pass the Company's resource screen process. It should further be noted that the plants which make up the BMPs are included in the PCA through the end of their current PPA terms. Upon expiration of those contracts, those plants are eligible to participate in the MISO markets.

Through the litigation of this proceeding, it has become apparent that the BMPs take issue with the Company not considering the cost to extend or enter new PPAs with the existing plants which make up the BMPs. Beyond the fact that the Company has no obligation to do that, and the fact that the BMP PPAs are not set to expire for numerous years, the flaw in the BMPs' position is that the Company did not have adequate information to determine the cost of new PPAs or PPA extensions with the BMPs in the development of this IRP. And throughout this proceeding, the BMPs have failed to produce any evidence in the record establishing the costs that the BMPs could agree to in new PPAs or PPA extension. As explained in the rebuttal testimony of Company witness Troyer, the cost of current BMP PPAs have not been historically competitive with either market pricing or the Company's more-recent competitive procurement of new solar resources. Based on the cost of the BMPs' existing PPAs, the Company had no reason to

assume that the BMP suppliers were willing to accept lower rates than what is provided for in the current agreements during the development of this IRP.

Therefore, prior to addressing the individual objections offered by the BMPs, it is important to acknowledge that: (i) the Company has no obligation to enter new PPAs or extend existing PPAs with any of the BMPs; (ii) the Company did consider biomass plants in the development of its IRP and that type of resource was shown not to be a viable option on an economic or cost basis; (iii) the BMPs have failed to produce any evidence establishing the costs that the BMPs could agree to in new PPAs or PPA extension, and (iv) the existing BMP PPA cost information available to the Company establishes that the BMPs are not competitive with either market pricing or the Company's recent competitive procurement results.

Q. Beginning on page 17 of his contested settlement direct testimony, Mr. Polich recommends modifications to the proposed Settlement Agreement which would provide PPA extensions to the BMPs. Should the Commission adopt any changes to the proposed Settlement Agreement?

A. No. As explained on page 7 of Staff witness Proudfoot's direct testimony supporting the Settlement Agreement, Paragraph 22 of the Settlement Agreement provides that if the Commission rejects or modifies the Settlement Agreement or any provision of the Settlement Agreement, the Settlement Agreement shall be deemed to be withdrawn. See Exhibit A-150 (RTB-5), page 17, Paragraph 22. This is standard language which preserves

the bargain that the settling parties negotiated. Since the Settlement Agreement cannot be modified, the BMPs' requested modifications should be rejected by the Commission.

The BMPs' requested modifications to the settlement agreement are also beyond the scope of this contested settlement proceeding. As set forth in the Commission's June 7, 2019 Order Approving Settlement Agreement in Case No. U-20165, other proposed versions of settlements not adopted by the parties who signed the settlement agreement are not within the scope of issues to be decided by the Commission in a contested settlement proceeding:

> The Commission agrees with Consumers that SEIA's proposal is outside the scope of this contested settlement agreement. The issue to be decided in this case is whether the criteria set forth in Rule 431(5)(a) through (c) have been satisfied so that the Commission may approve of the settlement agreement at issue here. Other proposed versions of settlements not adopted by the parties who signed the settlement agreement are not properly before the Commission. Further, the Commission agrees with the Staff that SEIA's proposal should not be used to derail the settlement agreement in this case. Accordingly, the Commission rejects SEIA's recommendation to make approval of the settlement agreement contingent on SEIA's proposal. [MPSC Case No. U-20165, June 7, 2019 Order Approving Settlement Agreement, page 82.]

Since the BMPs' proposed Settlement Agreement modifications are beyond the scope of this contested settlement proceeding, they should be rejected by the Commission.

Furthermore, as set forth above, the BMPs have failed to produce any evidence in the record establishing that extended PPAs with the BMPs would be economic compared to other resource options. And the record establishes just the opposite. Based on historic information related to existing PPAs, the BMPs are not competitive with either market pricing or the Company's recent competitive procurement results. Therefore, even if the Settlement Agreement could be modified, which it cannot, and if the BMPs' proposal was

within the scope of this proceeding, which it is not, there is still no basis to adopt the BMPs recommended modifications to the Settlement Agreement because the record does not establish that the PPA extensions with the BMPs would be economic compared to other resource options.

B. CAPACITY POSITION

Q. Beginning on page 6 of his contested settlement direct testimony, Mr. Polich claims that the Settlement Agreement PCA will result in excess capacity between 2023 and 2030 and capacity shortages between 2031 and 2038. Do you agree?

A. I do not agree with Mr. Polich's generalizations regarding the Company's capacity position under the PCA, as modified by the Settlement Agreement. Specifically, I do not agree that the Settlement Agreement PCA results in capacity shortages. As explained in response to Wolverine witness King, under the PCA, as modified by the Settlement Agreement, the Company maintains sufficient capacity to serve customers. See Figure 1 of this second rebuttal testimony. Furthermore, below I discuss that Mr. Polich's own Exhibit BMP-7 (RAP-7) supports the capacity sufficiency of the Settlement Agreement.

With respect to the BMPs allegations of excess capacity, I also disagree with Mr. Polich that the capacity amounts in any year of the PCA is to the detriment of customers. I will discuss this in more detail below.

Q. On page 8, beginning on line 1 of his contested settlement direct testimony, Mr. Polich states the Settlement Agreement results in excess capacity, exposing customers to unreasonable expense. Mr. Polich opines that the addition of the Covert Plant in 2023 means customers will be paying for two years of "unnecessary costs for the Covert capacity that is unnecessary" and that one-time solicitation "is not needed until 2030." Do you agree with Mr. Polich's claims?

A. No. The record in this case demonstrates that the Company initially proposed to acquire the Covert Plant *and* the DIG, Kalamazoo, and Livingston plants to retire Karn Units 3 and 4, which are capacity resources, *and* Campbell Units 1, 2, and 3, which are capacity and energy resources. In other words, the acquisition of any particular unit was not assigned to the retirement of any particular unit. The acquisitions and retirements were considered as a whole based on the impact of the energy and capacity lost and the energy and capacity gained. Through the settlement process, the settling parties agreed that the Company would not purchase the DIG, Kalamazoo, and Livingston plants, as originally proposed. However, in order to retire Campbell Units 1, 2, and 3, the Company still needs to acquire the Covert Plant and the Purchase Sale Agreement ("PSA") for that plant provides for the purchase in 2023. Therefore, Mr. Polich is plainly incorrect in alleging that the Covert Plant capacity is "unnecessary." Nearly every party in this proceeding supported acquisition of the Covert Plant in 2023. This acquisition brings dispatchable baseload capacity into MISO and Zone 7 and will support the replacement of the energy and capacity of the units proposed for retirement in this IRP.

Mr. Polich has also not established that the Company has any ability to move the start date of the Covert Plant purchase. Since the PSA provides for the Covert Plant to be

purchased in 2023, attempting to move that date is not possible under the terms of the agreement. Furthermore, even if the Covert Plant does provide surplus energy and capacity for a short period, the Company can monetize the energy and capacity of the Covert Plant by selling it into the MISO markets and using the resulting revenue to lower power supply costs to the benefit of customers. The Company disagrees with Mr. Polich that customers will face economic harm as a result of the Company owning the Covert Plant.

Moreover, without the acquisition of the DIG, Kalamazoo, and Livingston units, as initially proposed by the Company, the one-time solicitation included in the proposed Settlement Agreement also supports the retirement of Campbell Units 1, 2, and 3. It is expected that the 500 ZRCs of dispatchable generation and the 200 ZRCs of intermittent and non-intermittent clean resources will provide sufficiency of supply to support retirement of the Campbell Units. However, until such resources are acquired and operational on behalf of customers, the Settlement Agreement provides for continued operation of Karn Units 3 and 4, which provide low-cost capacity for the benefit of customers. The continued operation of Karn Units 3 and 4 further addresses reliability concerns for customers. These low-cost capacity resources will continue to be evaluated in future IRPs, along with other existing assets, to identify if they continue to serve customer needs reliably and affordably. The Settlement Agreement identifies the plan to cease operations of these units by May 31, 2031, however, the Company intends to manage its capacity surplus position in the best interests of its customers. Because the one-time solicitation will support the retirement of Campbell Units 1, 2, and 3, and the need for continued operations of Karn Units 3 and 4 can be assessed in the future, the BMPs have

not established that the one-time solicitation is unnecessary or to the detriment of customers.

Q. Beginning on page 13 of his contested settlement direct testimony, Mr. Polich claims that the PCA, as modified in the Settlement Agreement, results in a capacity shortfall position in years 2031 through 2038. Do you agree with Mr. Polich's alleged capacity shortfall?

A. No. The calculation described by Mr. Polich and included as Exhibit BMP-9 (RAP-9) is misleading and inconsistent with the modeling presented in this case. Company witness Clark discusses the issue of solar accreditation itself, in further detail. Mr. Polich suggests that *if* a change to solar accreditation is made at MISO, the PCA would result in capacity shortfalls eight years into the future. This argument is not compelling for two primary reasons.

First, the PCA was developed using current MISO solar capacity accreditation practices. While discussions in MISO have raised the possibility of changes to solar capacity accreditation, it would be premature to adopt such changes ahead of MISO itself issuing the rule change. In fact, at the Company's existing solar facilities, capacity accreditation, based on actual performance, has been as high as 65%. While the possibility of lowering the accreditation is under consideration, actual performance will ultimately dictate the levels of capacity customers receive from these resources. Mr. Polich's Exhibit BMP-7 (RAP-7) actually presents a capacity position for the Company under a 50% solar accreditation and demonstrates that the Company has no capacity shortfall through 2040.

See Exhibit BMP-7 (RAP-7), line 24.[2] Table 1, below, which is pulled directly from the referenced line of Exhibit BMP-7 (RAP-7) illustrates the capacity position calculated by Mr. Polich.

Table 1: Capacity Position Presented in Exhibit BMP-7 (RAP-7)

Year	Settlement Agreement Net Capacity in Excess of PRMR (Line 24)
2021	617
2022	154
2023	1,249
2024	1,517
2025	1,201
2026	1,271
2027	1,457
2028	1,700
2029	1,942
2030	927
2031	138
2032	88
2033	78
2034	118
2035	396
2036	224
2037	568
2038	934
2039	1,270
2040	1,514

Since Mr. Polich's own exhibit clearly supports the sufficiency of capacity in the Settlement Agreement, as set forth above, his claim of a capacity shortfall should be rejected.

Second, Mr. Polich's alleged and miscalculated capacity shortfall is projected to occur eight years into the future. The Company will file at least one, if not multiple, IRPs

[2] Note that Figure 1 in my second rebuttal testimony provides the Company's actual PCA capacity position, as modified in the Settlement Agreement. The Company is only providing the purported "Settlement Agreement Net Capacity in Excess of PRMR," as provided in Exhibit BMP-7 (RAP-7), to demonstrate that Mr. Polich's own calculations show that the PCA has no capacity shortfalls. Exhibit BMP-7 (RAP-7) contains errors which include the omission of the battery storage deployment program beginning in planning year 2024/2025.

between now and that time. If changes to solar accreditation occur at MISO, the Company has ample time to respond and adjust the PCA. Furthermore, as set forth above, under the PCA, as modified by the Settlement Agreement, and the numerous mechanisms provided for in the Settlement Agreement which will allow the Company to address that projected shortfall long before it happens, the Company will maintain sufficient capacity to serve customers.

C. ONE-TIME SOLICITATION

Q. Beginning on page 9 of his contested settlement direct testimony, BMP witness Polich suggests that the one-time solicitation proposed in the Settlement Agreement is "deeply flawed." Do you agree with Mr. Polich's claims regarding the solicitation?

A. No. The first "flaw" Mr. Polich claims is that the one-time solicitation timing will favor existing generation facilities, and he cites engineering, financing, and construction time limitations, as well as delays in the MISO interconnection process. The Company disagrees that this is a flaw in the design of the solicitation. As explained above, the resources acquired in the one-time solicitation will help replace the capacity and energy lost by Campbell Units 1, 2, and 3 in 2025. Furthermore, beyond speculating what plants can participate, Mr. Polich fails to establish anything unreasonable about the solicitation. The solicitation will provide capacity and energy to meet the needs of the Company and its customers, and the characteristics of the resources sought in the solicitation are consistent with the results of the extensive modeling performed by the Company in this case. As explained by Company witness Sara T. Walz, the Company's modeling selected natural gas units to satisfy large capacity and energy needs, which is consistent with the characteristics sought in the 500 ZRC tranche. The Company's modeling also selected clean resources, like solar, which is consistent with the 200 ZRC tranche.

Mr. Polich's second claimed flaw relies on incorrect data assumptions. Specifically, Mr. Polich incorrectly states that MISO Zone 7 is projected to be 397.4 ZRCs short in 2023. See BMP witness Polich's Contested Settlement Direct, page 10. This is inaccurate. Mr. Polich has incorrectly interpreted page 13 of Exhibit BMP-8 (RAP-8), which provides the results of the Planning Year *2022/2023* Planning Resource Auction ("PRA"). The results presented in this summary are not indicative of any projection of Zone 7 in Planning Year 2023/2024, as stated in Mr. Polich's testimony. Further, the Company's addition of the Covert Plant results in an increase of capacity resources of over 1,100 ZRCs in Zone 7 in 2023.

Mr. Polich correctly stated that the MISO PRA for planning year 2022-2023 resulted in higher clearing prices than recent historical averages, as well as a shortfall position for Zone 7. However, the PCA, as presented in this Settlement Agreement, provides for long-term capacity sufficiency for customers. Mr. Polich has himself acknowledged that the Settlement Agreement will provide a capacity surplus for customers for years 2023 through 2030. See BMP witness Polich's Contested Settlement Direct, page 8. As has been discussed repeatedly in this case, Consumers Energy customers are not responsible for resource adequacy requirements for the entire Zone 7, which includes customers served by alternative energy suppliers ("AESs") as well as other utilities. The Settlement Agreement ensures PRMRs are met for Consumers Energy customers. Please see the testimony of Company witness Clark for additional discussion on this matter.

Mr. Polich's third claimed flaw suggests that the BMPs are precluded from participation in the one-time solicitation because of their existing contracts and dispatchability constraints. See BMP witness Polich's Contested Settlement Direct,

page 11. However, this limitation is untrue, and one created by the BMPs. At the outset, Mr. Polich's alleged flaw is a red herring because the Company was under no obligation to issue the one-time solicitation in a manner that would align sought PPA start dates with the expiration of the BMPs current PPAs. Because the current PPAs of the BMPs expire in different years between 2025 and 2030, it would not be possible to align the one-time solicitation with the expiration of every BMP PPA. Furthermore, while the solicitation is seeking bids which will provide the Company with capacity credit in the MISO Zone 7 starting in the 2025 Planning Year, this would not preclude certain BMPs from submitting bids which take into account current contractual commitments. Such contractual commitments could be evaluated in the solicitation when determining the overall economics of a bid.

Mr. Polich also suggests that the BMPs are excluded from the 500 ZRC tranche of the one-time solicitation because it "provides for hourly dispatch" and the BMPs are "dispatched on 24 hours-notice." BMP witness Polich's Contested Settlement Direct, page 11. However, Mr. Polich does not correctly represent the Settlement Agreement language which provides that "[t]his tranche will seek dispatchable, nonintermittent generation *capable* of dispatching up or down in every hour of the year in response to wholesale energy market signals." See Exhibit A-150 (RTB-5), page 6, Paragraph 6 (emphasis added). It is also notable that during this proceeding Mr. Polich has claimed that the BMPs "generation facilities can provide *around the clock*, renewable, *dispatchable* and reliable power generation." See 7 TR 2684 (emphasis added). Mr. Polich's statements in his contested settlement direct testimony are therefore inconsistent with his prior testimony in this proceeding which suggested that the BMPs are "dispatchable" "around

the clock."[3] It should also be noted that, under existing BMP PPAs, certain BMPs are offered into the MISO Day-Ahead Market as units which can dispatch on an hourly basis. Since the MISO Day-Ahead Market clears the day prior to operation, the plants are provided dispatch notice prior to actual operation.

Mr. Polich's fourth alleged flaw in the one-time solicitation suggests that the second tranche which seeks to procure 200 ZRCs does not define "clean capacity resources" and could mean any resources cleaner than "Consumers existing generation resources" and therefore "natural gas plants could offer proposals." BMP witness Polich's Contested Settlement Direct, page 11. This fourth alleged flaw is not an actual flaw in the one-time solicitation and instead represents Mr. Polich's interpretation of the second tranche of the one-time solicitation. The Settlement Agreement was entered by 18 parties and represents a compromise reached by those parties. The terms of the Settlement Agreement speak for themselves and Mr. Polich's observations are irrelevant. Nevertheless, Mr. Polich's interpretation of the second tranche simply does not make sense. The Company's generation portfolio includes fossil fuel and clean capacity resources such as solar and hydro generation. Since the Company already possesses clean capacity resources in its generation portfolio, Mr. Polich's interpretation that this tranche "can mean any generation resource *cleaner* that Consumers existing generation resources" (emphasis added) would produce absurd results because nothing could be "cleaner" than the clean capacity resources the Company already has.

[3] Mr. Polich has presented numerous claims in this proceeding that the BMPs are dispatchable and has not previously explained any of the limitations on dispatchability expressed in his contested settlement direct testimony. See, e.g., 7 TR 2684, 2689, 2691, 2698, 2703, 2714, 2715, 2721, 2722, 2728. Mr. Polich also compared the operation of the BMPs to the DIG gas plant, claiming that "[a]s with DIG, these plants are dispatchable and provide equivalent availability." 7 TR 2715.

Mr. Polich also fails to provide the full text describing the "clean capacity resources" that can participate in the second tranche of the one-time solicitation. The Settlement Agreement specifically provides that "[t]his tranche will seek intermittent resources and dispatchable, nonintermittent clean capacity resources *(including battery storage resources)* providing capacity which meets the Local Clearing Requirement of MISO Zone 7." Exhibit A-150 (RTB-5), page 6, Paragraph 6 (emphasis added). Since the Settlement Agreement provides "battery storage resources" as an example of the "dispatchable, nonintermittent clean capacity resources" that can participate in the second tranche, the Settlement Agreement is not "very ambiguous," as Mr. Polich claims. See BMP witness Polich's Contested Settlement Direct, page 11.

Mr. Polich's fifth alleged flaw in the one-time solicitation assumes that the "One-Time Solicitation will likely result in Consumers acquiring substantial amount of natural gas capacity in addition to the Covert capacity" and discusses "volatility of natural gas pricing." BMP witness Polich's Contested Settlement Direct, page 12. In making this argument, Mr. Polich is speculating on the outcome of the one-time solicitation for 500 ZRCs of dispatchable resources, which is unproductive. For the reasons set forth by Company witness Brian D. Gallaway in the record, Mr. Polich's discussion of gas price volatility should also be rejected. Mr. Gallaway established that gas price volatility is not expected to continue into the future. Furthermore, Mr. Polich's suggested "need for a more fuel diverse generation portfolio" (see BMP witness Polich's Contested Settlement Direct, page 12) ignores that the Company will have an incredibly diverse resource portfolio that includes: pumped storage and hydro generation, gas generation, wind generation, solar generation, energy efficiency, DR, and emerging technologies such as grid modernization

and battery storage to meet the future demand of its customers. The Company also maintains PPAs with numerous technology types.

Mr. Polich's sixth and final alleged flaw with the one-time solicitation suggests that it is flawed because it solicits "only intermittent generation because solar generation with battery storage will likely be too expensive to compete with solar generation without battery storage and due to shortages of materials." BMP witness Polich's Contested Settlement Direct Testimony, page 12. Here, again, Mr. Polich is speculating on the outcomes of the 200 ZRC tranche. The one-time solicitation is a competitive bidding process which will consider the value of the resources which are bid. If certain resources are "too expensive," as Mr. Polich claims, that issue will naturally be resolved through the evaluation and ranking of eligible bids.

D. <u>OTHER ISSUES</u>

Q. On page 14 of his contested settlement direct testimony, Mr. Polich states that the Settlement Agreement does not "meet the intent of being carbon neutral by 2040 as [sic] stated in Settlement Section 16." Do you agree?

A. No. First of all, Mr. Polich purported "intent of being carbon neutral by 2040" is not a term of the Settlement Agreement. Paragraph 16 of the Settlement Agreement merely reiterates that the Company's filed IRP "set forth a proposal to be Carbon Neutral by 2040 and retire all coal generation by 2025." See Exhibit A-150 (RTB-5), page 13, Paragraph 16. While the Company still aims to be carbon neutral by 2040, this is not a requirement in the Settlement Agreement. Still, there is nothing in the Settlement Agreement that will necessarily impede the Company's ability to meet its goal.

In an attempt to support his argument regarding not meeting carbon neutrality by 2040, Mr. Polich asserts that "Consumers is relying on Covert and 200 MW of generation

from PPAs originating under the One-Time Solicitation" and that "[t]hese are fossil generation resources and are not carbon neutral." BMP witness Polich's Contested Settlement Direct, page 14. However, Mr. Polich's assumptions are not accurate. First, as made clear in my direct testimony, the 20-year capacity plan provided by the Company in this IRP assumed cessation of operations of the Covert Plant by May 31, 2040. The final solution in 2040 will vary dependent upon the evolution of cleaner technologies, the possibility of carbon sequestration technologies, and potential for carbon offsets. Second, Mr. Polich is incorrect that the Company will acquire 200 MWs of "fossil generation resources" in the one-time solicitation that will operate beyond 2040. Mr. Polich implies that the 200 ZRC tranche, which can result in contracts up to 25 years, could result in fossil generation resources but that is inconsistent with the description of that tranche which provides that only "intermittent resources and dispatchable, nonintermittent clean capacity resources (including battery storage resources)" are eligible. See Exhibit A-150 (RTB-5), page 6, Paragraph 6. Mr. Polich has therefore not established that the Covert Plant purchase or the one-time solicitation will result in the Company not meeting its carbon neutrality goal.

Mr. Polich also suggests the resource mix included in the PCA will impact the Company's ability to meet its carbon neutrality goal. Specifically, Mr. Polich questions solar production levels, a lack of battery storage, and levels of energy market purchases. See BMP witness Polich's Contested Settlement Direct, page 14. These matters have all been extensively addressed and refuted by the evidence provided by the Company in this case. First, the Company utilized and successfully supported use of National Renewable Energy Laboratories ("NREL") projections for solar operating factors. Testimony

provided by Company witness Jeffrey E. Battaglia supports these projections from third-party and reputable sources. Secondly, the Settlement Agreement provides for an incremental 75 MW of battery storage capacity by 2027, as compared to the initial PCA. This brings the total capacity of battery storage to 550 MW installed throughout the study period on top of 1,170 MW of Ludington pumped storage capacity. Lastly, purchase of energy from MISO's energy market is a benefit to customers, to ensure the lowest-cost resources are used to meet their needs. The Company's Net Zero Carbon goal accounts for carbon emissions from those market purchases, as discussed in testimony presented by Company witness Heather A. Breining.

Q. On page 7 of his contested settlement direct testimony, Mr. Polich suggests that potential risk of capacity shortages in Zone 7 could prevent retirement of Karn Units 3 and 4. Specifically, Mr. Polich suggests that the units could be designated as a System Support Resource ("SSR") by MISO. Does this represent a significant risk to customers?

A. No. Mr. Polich's discussion of an SSR designation for Karn Units 3 and 4 does not represent a significant risk to customers because, as discussed above, Mr. Polich's position is based on a flawed interpretation of the Company's future capacity position. Mr. Polich has failed to establish that the Company will experience a capacity shortage between 2031 and 2038 and therefore has not established that there is a "likelihood that MISO will designate one or more of Consumers' fossil fuel Karn generating plants as System Support Resource and not allow their retirement." BMP witness Polich's Contested Settlement Direct, page 7.

Mr. Polich also fails to accurately represent the customer benefit of Karn Units 3 and 4 and what an SSR designation actually means for customers. An SSR designation would not be due to a capacity or energy shortfall. An SSR designation would result from an electric transmission system deficiency that must be mitigated before Karn Units 3 and 4 could be retired. Karn Units 3 and 4 will continue to operate to ensure near-term reliability for the benefit of Consumers Energy customers. These units may be operated through May 31, 2031, depending on the Company's capacity needs and the outcome of the Company's resource procurement efforts. The cost to maintain operations of Karn Units 3 and 4 is very low[4], compared to many alternatives available to meet load obligations which means that customers will not be required to pay high costs for extensive capacity and reliability benefits provided by these units. Moreover, even if Karn Units 3 and 4 were designated as SSR units, the cost burden associated with that designation would shift to all customers who benefit from the reliability assets, in this case, all customers in Zone 7. Moreover, the SSR period would only be in place while system improvements are made to accommodate retirement of Karn Units 3 and 4. At the time the Company submits an Attachment Y with MISO, to initiate the process of retirement, if MISO designates the units as SSR for Zone 7, the entirety of the zone would then financially support the

[4] See page 1 of Exhibit A-51 (NJK-2) Revised, page 1 of Exhibit A-52 (NJK-3) Revised, and page 1 of Exhibit A-53 (NJK-4) Revised.

continued operation of the units. Therefore, an SSR designation does not pose an increased risk to customers.

Q. Beginning on page 15 of his contested settlement direct testimony, Mr. Polich suggests that there are risks associated with the Company's proposal solar generation. Do you agree with Mr. Polich's assessment?

A. No. For the reasons discussed in the second rebuttal testimony of Company witness Clark, the Company disagrees with Mr. Polich's assessments of the risks of solar procurement and development.

Q. On page 6 of his contested settlement direct testimony, Mr. Polich suggests that the Settlement Agreement "fails to consider both the employment and tax benefits of the Biomass Plants as well as the full panoply of their environmental benefits as identified in my initial direct testimony." Do you agree with Mr. Polich's criticism of the Settlement Agreement?

A. No. The BMPs positions on these issues were extensively refuted by the Company's record evidence and briefs. The BMPs position regarding the consideration of the employment and tax benefits of the BMPs is also based on a flawed reading of MCL 6t(8)(b). See BMPs' May 4, 2022 Objections, page 6. The BMPs' reading of the requirements of Section 6t(8)(b) is also incorrect. That provision addresses what the Commission shall determine in approving an IRP. See MCL 460.6t(8). In relevant part, Section 6t(8)(b) provides "[t]o the extent practicable, the construction or investment in a new or existing capacity resource in this state is completed using a workforce composed of residents of this state as determined by the commission." MCL 460.6t(8)(b). Section 6t(8)(b) therefore only applies when a utility is proposing to construct a new resource or invest in an existing

resource and aligns with the cost approval provision of the IRP law which allows utilities to seek pre-approval of those construction and investment costs in an IRP. MCL 460.6t(11) ("the commission shall specify the costs approved for the construction of or significant investment in an electric generation facility..."). There is no reasonable interpretation of Section 6t(8)(b) which could link that provision to a required evaluation of the "instate employment and tax benefits" of the BMPs. The Company does not own the BMPs and is not proposing any construction or investment related to those plants.

V. CONCLUSION

Q. Based on the contested settlement direct testimony filed by Energy Michigan, Wolverine, and the BMPs, have those parties established any basis for the Commission to reject the Settlement Agreement?

A. No. For the reasons discussed above, Energy Michigan and Wolverine have failed to establish that there are detrimental reliability and resource adequacy impacts related to the Settlement Agreement. Wolverine's assertion that the Company will experience a capacity deficiency in 2025 was also shown to be incorrect. As explained by Company witness Clark, Energy Michigan and Wolverine have also refused to provide the capacity projections and future capacity plans for Energy Michigan's AES members and Wolverine. Therefore, beyond the fact that Energy Michigan's and Wolverine's claims are incorrect about the impact of the Settlement Agreement on Zone 7, Wolverine's and Energy Michigan's failure to provide capacity forecasts and future capacity plans also makes clear that their criticisms of the Settlement Agreement cannot be sustained. Wolverine and

Energy Michigan have failed to establish any basis for the Commission to not approve the Settlement Agreement.

The BMPs have also failed to establish any basis for the Commission to not approve the Settlement Agreement. The BMPs positions should be rejected because: (i) the Company has no obligation to enter new PPAs or extend existing PPAs with any of the BMPs; (ii) the Company did consider biomass plants in the development of its IRP and that type of resource was shown not to be a viable option on an economic or cost basis; (iii) the BMPs have failed to produce any evidence establishing the costs that the BMPs could agree to in new PPAs or PPA extension; and (iv) the existing BMP PPA cost information available to the Company establishes that the BMPs are not competitive with either market pricing or the Company's recent competitive procurement results. For the reasons detailed above, the BMPs have also failed to establish any real flaws in the Settlement Agreement which would prevent the Settlement Agreement from being approved by the Commission.

Q. Does this conclude your second rebuttal testimony?

A. Yes.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-9

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

Exhibit 57

Jester 2021 Direct Testimony

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of CONSUMERS ENERGY COMPANY for approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and other relief.

Case No. U-21090

Volume 10

_____/

CROSS-EXAMINATION (Settlement Agreement)

Proceedings held via Microsoft Teams in the above-entitled matter before Sally L. Wallace, Administrative Law Judge with MOAHR, for the Michigan Public Service Commission, Lansing, Michigan, on Friday, May 20, 2022, at 9:06 a.m.

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(Continued)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **CONSUMERS ENERGY COMPANY** for Approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief.	U-21090 ALJ Sally L. Wallace

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TESTIMONY OF DOUGLAS B. JESTER
IN SUPPORT OF SETTLEMENT AGREEMENT

ON BEHALF OF

THE MICHIGAN ENVIRONMENTAL COUNCIL,
NATURAL RESOURCES DEFENSE COUNCIL, SIERRA CLUB,
AND CITIZENS UTILITY BOARD OF MICHIGAN

May 9, 2022

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I. INTRODUCTION

Q. Are you the same Douglas Jester who previously filed testimony in this case?

A. Yes.

Q. On whose behalf is this testimony being offered?

A. I am testifying on behalf of Michigan Environmental Council (MEC), Natural Resources Defense Council (NRDC), and Sierra Club (SC) (collectively, "MNS") and Citizens Utility Board of Michigan (CUB).

Q. What is the purpose of your testimony?

A. I am testifying on behalf of MNS and CUB to support the settlement agreement in this case.[1]

Q. Are you sponsoring any exhibits?

A. No.

Q. Please summarize your opinions regarding the settlement agreement.

A. The settlement agreement is in the public interest; represents a fair and reasonable resolution of this case; and is supported by substantial evidence. The settlement preserves the most beneficial aspects of Consumers' Proposed Course of Action, including the retirement of the entire Campbell plant and the permanent exit from coal generation in 2025; as well as the solar ramp-up and annual competitive solicitations for solar generation.

[1] Case No. U-21090, Settlement Agreement filed April 20, 2022.

The settlement also improves upon Consumers' initially-filed PCA by:

- Eliminating the purchase of certain gas plants from Consumers' affiliate CMS Enterprises;
- Providing for competitive solicitation of Power Purchase Agreements to backfill the retiring Campbell capacity, including a tranche of dispatchable, non-intermittent generation and a tranche of clean capacity (which includes battery storage resources);
- Maintaining Karn units 3-4 in operation to support resource adequacy;
- Reducing the return on equity for the proposed regulatory asset for the retiring Campbell plant;
- Providing additional support from Company shareholders to low-income customer bill assistance programs;
- Substantially maintaining the 50/50 procurement terms from the settlement in Case No. U-20165;
- Maintaining the Financial Compensation Mechanism methodology from the settlement in Case No. U-20165;
- Requiring further evaluation of transmission options to improve reliability and facilitate economic power imports;
- Advancing battery storage investments;
- Improving future analysis of line losses and avoided transmission and distribution costs in the evaluation of distributed resources, including residential demand response;

- Requiring environmental justice analysis in Consumers' next IRP;
- Providing for public filing of community transition plans for the Campbell and Karn sites; and
- Addressing issues under the Public Utility Regulatory Policies Act (PURPA) to the satisfaction of the parties who engaged on those issues.

The improvements to the PCA reflected in the settlement agreement resulted from extensive, arms-length negotiations between Consumers and the parties, and the settlement agreement is supported by the vast majority of the parties in this case. For these reasons, it is my opinion that the settlement is in the best interest of customers and the environment, and I wholeheartedly recommend that the Commission approve it.

II. OVERVIEW OF CONSUMERS' INITIAL PROPOSALS IN THIS CASE

Q. Please summarize the resource portfolio presented in Consumers' initial PCA in this case.

A. The PCA described in Consumers Energy's direct case included the following resource elements:

- Retire Karn units 3 and 4, which are oil/gas peakers, in May 2023;
- Retire coal-fired Campbell units 1, 2, and 3 in May 2025;
- Purchase the New Covert Generating Facility, a natural gas-fired plant, in May 2023;
- Purchase three gas plants owned by Consumers' affiliate, CMS Enterprises Company – Dearborn Industrial Generation (DIG), Kalamazoo, and Livingston – in May 2025;

- Continue procuring solar resources via annual competitive solicitations, with increases in projected utility-scale solar deployment throughout the 2020s and 2030s;
- Slow development of battery storage projects, with the first battery resources coming online in 2030;
- Make modest adjustments in Consumers' projected Energy Waste Reduction, Demand Response, and Conservation Voltage Reduction programs; and
- Pursue no new transmission projects or agreements to secure power imports from outside MISO Zone 7.

Q. Please summarize the principal financial requests that Consumers made in its direct case.

A. Apart from the gas plant acquisition costs, Consumers made two significant financial requests in its initial case.

First, Consumers proposed to establish a $1.5 billion regulatory asset for the unrecovered book balances of the Campbell plant and Karn units 3-4. Consumers also proposed to recover that asset through conventional ratemaking over the previously planned remaining life of the units, with recovery of depreciation expense and pre-tax weighted average cost of capital, or WACC, including return on equity.

Second, Consumers proposed to change the method by which its PPA Financial Compensation Mechanism, or FCM, is calculated. The settlement in Consumers' last IRP case, U-20165, provided the Company with an FCM calculated by multiplying the PPA

payments by Consumers' after-tax WACC using its total capital structure. In this case, Consumers proposed to increase the FCM by multiplying the PPA payments by Consumers' pre-tax WACC using its permanent capital structure. Using pre-tax WACC instead of after-tax WACC and using permanent capital structure instead of total capital structure would have increased Consumers' current PPA incentive by almost 50%.

Q. Did Consumers propose changing its solar procurement practices?

A. Yes. The most significant proposed change was to the allocation between Company-owned and PPA solar projects. In the settlement of Case No. U-20165, Consumers agreed to acquire at least 50% of its solar capacity acquired via PPAs and no more than 50% from company-owned projects or build-transfer agreements. In this case, the Company proposed to reverse that allocation and acquire at least 50% from company-owned resources and no more than 50% via PPAs.

III. REASONABLENESS OF THE SETTLEMENT AGREEMENT

Q. What does the settlement provide regarding the Campbell plant?

A. In paragraph 4(ii) of the settlement, the parties agree that Campbell units 1, 2, and 3 will retire on or before May 31, 2025.

Q. In your opinion, is retiring the Campbell plant a reasonable and beneficial settlement term?

A. Yes. First it should be noted that no party in this case opposed retirement of Campbell units 1 and 2. The Proposal for Decision (PFD) in this case also recommended approval of those retirements.

Further, retiring the entire Campbell plant will benefit both customers and the environment and is therefore in the public interest. After Karn 1 and 2 retire in 2023, Campbell 1-3 will be the last remaining coal units in Consumers' portfolio. The Campbell plant has a greater carbon impact than any other resource owned by the Company, and its retirement is critical to meeting state and federal climate goals, including the Michigan Healthy Climate Plan.[2] Because the Campbell plant emits other pollutants, such as SO_2, NO_x, and particulate matter, retiring Campbell is likely to also have health benefits in addition to those from reducing the Company's carbon output.

Extensive modeling conducted by Consumers and by MNS in this case demonstrated that retiring Campbell in 2025 is economic for customers. MNS witnesses Tyler Comings and Casey Roberts also explained that Campbell's continued operation poses regulatory risks due to Steam Electric Effluent Guidelines (SEEG) requirements and potential carbon costs. And witness Comings noted that retiring Campbell in 2025 will save customers more than $150 million of avoidable capital expenditures. In proposing Campbell's retirement, the Company also cited community and worker benefits of accelerated retirement over continued operation. The testimony, exhibits, and modeling regarding these issues provide substantial evidence to support the Campbell plant retirement.

Q. Please explain why Campbell's 2025 retirement is important for meeting the Michigan Healthy Climate Plan goals.

[2] Available at https://www.michigan.gov/egle/-/media/Project/Websites/egle/Documents/Offices/OCE/MI-Healthy-Climate-Plan.pdf?rev=d13f4adc2b1d45909bd708cafccbfffa&hash=99437BF2709B9B3471D16FC1EC692588, last checked May 6, 2022.

A. Governor Whitmer's Executive Directive, which initiated development of the Michigan Healthy Climate Plan, directed that the plan should result in 26-28% reduction in economy-wide greenhouse gas emissions from 2005 to 2025.[3] The following table displays Michigan's GHG emissions in 2005 and the associated goals of the Michigan Healthy Climate Plan as I compiled them from reports by the US Energy Information Administration:[4]

Michigan Energy GHG Emissions 2005 (million metric tons CO2 Equivalent)	Residential Sector	Commercial Sector	Industrial Sector	Transportation Sector	Electric Power Sector	All Energy Sectors
Coal	0.0	0.3	7.3	0.0	67.8	75.4
Petroleum Products	4.6	0.9	5.8	53.8	0.8	65.9
Natural Gas	19.3	9.4	12.0	1.5	7.0	49.2
Total Energy-Related	23.9	10.6	25.1	55.3	75.6	190.5
Non-Energy 2002 GHG Emissions						29.3
Total 2005 GHG Emissions						219.8
NDC Goal 2025			26% Reduction from 2005			162.7
NDC Goal 2030			50% reduction from 2005			109.9
Whitmer Goal 2050			Net Zero by 2050			0.0
Energy Emissions Goal 2025			Assume 0% reductions in non-energy GHG emissions since 2005			133.4
Energy Emissions Goal 2030			Assume 25% reduction in non-energy GHG emissions since 2005			88.0
Energy Emissions Goal 2050			Assume elimination or offsets by 2050			0.0

2019 is the most recent full compilation of similar data available from EIA. As of 2019, the corresponding emissions were as shown in the following table:

[3] Executive Directive 2020-10 affirmed this goal that she first adopted in Executive Directive 2019-12.

[4] State Carbon Dioxide Emissions Data - U.S. Energy Information Administration (EIA), available at https://www.eia.gov/environment/emissions/state/, last checked May 6, 2022.

Michigan Energy GHG Emissions 2019 (million metric tons CO2 Equivalent)	Residential Sector	Commercial Sector	Industrial Sector	Transportation Sector	Electric Power Sector	All Energy Sectors
Coal	0.0	0.0	4.0	0.0	44.2	48.2
Petroleum Products	3.5	1.5	6.2	50.5	0.6	62.2
Natural Gas	20.2	11.1	10.6	0.0	16.8	58.7
Total Energy-Related	23.7	12.6	20.8	50.5	61.6	169.2
Energy Emissions Reduction Needed by 2025						35.8
Energy Emissions Reduction Needed by 2030						81.2

Since policy and economic trends related to the residential, commercial, industrial, and transportation sectors have not obviously caused a change in emissions trends in these sectors, I used those trends to project a similar table for 2025. In addition, I used EPA's facility-level GHG emissions inventory[5] to identify 2019 GHG emissions from Michigan power plants that have since retired or been committed to retire by 2025, including the Campbell plant, and assumed that reduction from Electric Power Sector emissions. That forecast provides the following comparable table:

2025 GHG Emissions Reductions (million metric tons CO2 equivalent)	Residential Sector	Commercial Sector	Industrial Sector	Transportation Sector	Electric Power Sector	All Energy Sectors
Replace Coal Generation with Clean Generation					-17.8	
EV Sales Ramp to 100% by 2035				-3.5		
Accelerate Heating Efficiency & Electrification to 3.5%/yr	-5.6	-2.6	-4.1			
2025 Remaining Energy-Related Emissions	18.1	9.9	16.7	47.0	43.8	135.5
2025 Gap						2.1

[5] EPA Facility Level GHG Emissions Data, available at: https://ghgdata.epa.gov/ghgp/main.do#/facility/, lasted checked May 9, 2022.

Assuming the Campbell retirement and no new gas-fueled generation, there is a gap of 2.1 million metric tons CO2 equivalent (MMT CO2eq) between the 2025 goal of the Michigan Healthy Climate Plan and what is likely to be achieved. Since the Campbell plant annual emissions are approximately 8.285 MMT CO2eq, it is clearly not possible to meet the 2025 goal of the Michigan Healthy Climate Plan without the retirement of the Campbell plant by 2025. The retirement of Campbell is therefore critical to meeting the Climate Plan's goal.

Further, the Michigan Healthy Climate Plan calls for the retirement of all coal generation by 2030, which would necessarily include the Campbell units.

Q. What does the settlement provide regarding solar generation?

A. By approving the PCA except as modified in the settlement agreement, paragraph 1 of the agreement approves Consumers' continued ramp-up of solar resources – an initiative first approved as part of Consumers' 2018 IRP. In the 2018 case, the Commission approved a plan that included approximately 5 GW nameplate of new solar resources in the 2020s. In this case, Consumers proposed to continue those additions and also procure an additional 2 GW of solar in the 2030s above the levels included in the 2018 IRP. Paragraph 8 of the settlement agreement provides that Consumers will continue to utilize annual competitive solicitations to procure these solar resources.

Q. In your opinion, is approval of Consumers' solar additions a reasonable and beneficial settlement term?

A. Yes. In approving the settlement in U-20165, the Commission recognized that Consumers

Energy's planned solar ramp-up was both groundbreaking and environmentally beneficial. The Commission also endorsed the use of the annual solicitations to promote competition that would keep costs down and benefit customers. These public interest benefits, which the Commission has already recognized, will continue with the new settlement.

Q. What does the settlement provide for regarding the acquisition of gas plants?

A. First, the parties agree at paragraph 2 to Consumers' acquisition of the Covert plant, and that the purchase costs for that plant of $815 million are reasonable and prudent.

Second, the parties agree at paragraph 2 that Consumers will not obtain ownership of the three CMS plants: DIG, Livingston, and Kalamazoo.

Q. In your opinion, are the settlement terms regarding the acquisition of gas plants reasonable and beneficial?

A. Yes. With respect to Covert, no party opposed Consumers' acquisition of that plant, and the PFD recommended approving it. As testimony by both Staff and Consumers pointed out, because Covert is currently in PJM, Consumers' acquisition of Covert will add 1,114 Zonal Resource Credits or ZRCs to MISO Zone 7. That action will support reliability for Consumers as well as overall resource adequacy for Zone 7. For these reasons, acquisition of Covert is both in the public interest from a reliability and resource adequacy standpoint, and it is supported by substantial evidence in the record of this case.

Consumers' agreement not to acquire the CMS plants is also in the public interest and supported by substantial evidence. The record in this case showed myriad concerns regarding the CMS acquisitions – including issues with respect to affiliate transactions; the

nature of the gas plant RFP solicitation that led to the proposed purchase of these plants; and related issues. Staff, the Attorney General, and MNS all submitted substantial testimony and exhibits regarding these issues, and the hearing included substantial live testimony concerning them as well. In addition, parties including MNS, the Clean Energy Organizations (CEOs), and the Great Lakes Renewable Energy Association also provided evidence concerning certain risks associated with acquisition of those plants. Based on all of this evidence, the PFD also recommended against acquisition of the CMS plants.

Consumers has since come up with prudent plans to backfill capacity from retiring Campbell units by other means. I describe those plans next. Finally, it is worth noting that Staff supported in testimony Consumers' acquisition of Covert but not the CMS plants. The acquisition of some, but not all, of the assets Consumers sought to acquire is a self-evidently reasonable compromise.

Q. Which resources would replace Campbell's retiring capacity?

A. Under the settlement, Campbell's capacity will be replaced by a mix of resources. First, acquisition of the Covert plant will provide Consumers most of the energy and capacity currently provided by Campbell. Second, the settlement includes a one-time solicitation for PPAs that will provide up to 700 ZRCs of energy and capacity. These PPAs would be added to the Company's resource portfolio in the 2025 Planning Year – coinciding with the retirement of Campbell.

Q. Please describe the one-time solicitation of capacity and energy for the 2025 Planning Year.

A. In paragraph 6 of the settlement, the parties agree that Consumers will issue a one-time competitive solicitation for PPAs to begin in PY 2025. The solicitation will contain two tranches. The first tranche will seek up to 500 ZRCs of energy and capacity for up to 10 years from dispatchable, non-intermittent generation. The second tranche will seek up to 200 ZRCs of energy and capacity for up to 25 years from clean energy resources (including battery storage).

Q. In your opinion, is the one-time competitive solicitation a reasonable and beneficial settlement term?

A. Yes. The first tranche will provide energy and capacity of similar characteristics to what Consumers sought via the proposal to acquire the CMS plants. However, soliciting 10-year PPAs instead of acquiring affiliate assets planned to remain in rate base until 2040 will reduce risks to customers. Further, a solicitation for PPAs addresses one of the issues with the earlier RFP identified by parties and the PFD, which was that the earlier RFP only sought assets for purchase. Obtaining power via PPAs also addresses some of the other risks identified in the record, namely, those related to environmental permitting and fixed operating and maintenance expenses. Finally, the PPA approach is consistent with MNS modeling plans 1 and 3 discussed by witnesses George Evans and Tyler Comings. Those plans proposed using capacity purchases as part of lower-cost portfolios that retired

Campbell 3 without buying most or all of the CMS plants.

The second tranche is also beneficial to the public interest and supported by substantial evidence. It will provide additional clean energy resources for Consumers' portfolio, with the attendant benefits I discussed earlier in my testimony. It is also consistent with my testimony that Consumers should solicit for up to 750 MW of solar resources per year rather than 500 MW – a recommendation the PFD also adopted.

Q. What does the settlement provide regarding Karn units 3-4?

A. Paragraph 4(i) of the settlement provides that Karn units 3-4 will not retire in 2023 but instead will continue operating and retire on or before their previously planned retirement date of May 31, 2031, absent extraordinary circumstances.

Q. In your opinion, is the Karn retirement date a reasonable and beneficial settlement term?

A. Yes. Karn 3-4 are large peaking units already owned by Consumers. They provide substantial capacity but operate infrequently. Continuing to operate Karn 3-4 supports Consumers' attainment of planning reserve margin requirements by maintaining more than 780 ZRCs in the Company's portfolio. It also supports resource adequacy in Zone 7, for the same reason. Public health and climate impacts from Karn 3-4 are minor because the units operate so infrequently; in recent years their capacity factor has been substantially less than 5%. Keeping Karn 3-4 in operation also removes its unrecovered net book value from the total balance of the regulatory asset that Consumers seeks, which will now be limited to the balance for the Campbell plant, lowering the costs of the regulatory asset for

customers.

Q. What does the settlement provide regarding Consumers' request for the regulatory asset you just mentioned?

A. In paragraph 5 of the settlement, the parties agree that after retirement of the Campbell plant in 2025, the return on equity used to calculate the WACC for the regulatory asset will be 9.0%.

Q. In your opinion, is this regulatory asset provision a reasonable and beneficial settlement term?

A. Yes. Consumers has taken a very firm position that it will not retire Campbell in 2025 without being able to recover a return of and on the unrecovered balance. Therefore, it was necessary for the other parties to agree with a regulatory asset based on WACC for this settlement to occur and to facilitate Consumers' permanent exit from coal generation three years from now. On the other hand, setting the ROE at 9.0% for the calculation of the WACC on the regulatory asset is a significant compromise for Consumers, as that figure is substantially lower than the authorized ROE of 9.9% that the Commission approved in Consumers Energy's last electric rate case, U-20963. In addition, it is my understanding that the Attorney General negotiated the low-income bill assistance provision I describe next in tandem with the compromise on the regulatory asset, which further balances the burdens and benefits of this important financial component of the agreement.

Q. What does the settlement provide regarding support from Company shareholders to low-income customer bill assistance programs?

A. Consumers agreed in paragraph 13 of the settlement to donate funds to its low-income bill assistance programs. These donated funds will not be recovered in rates. Consumers will donate $5 million in 2022 and $2 million per year for the rest of the term of the regulatory asset for the Campbell plant. Consumers will consult with the Attorney General and Staff on the recipient low-income fund, and will provide an annual report to the Commission.

Q. In your opinion, are the low-income assistance donations a beneficial settlement term?

A. Yes. The need for additional low-income customer bill assistance has been demonstrated both in recent Consumers electric rate cases and in recent Consumers EWR cases, and recognized by the Commission in a variety of orders.[6] Prohibiting recovery of these funds in rates will ensure that they come from shareholders, which is a reasonable component of the overall compromise on the regulatory asset and ROE.

Q. What does the settlement provide regarding the allocation of future solar procurements?

A. Paragraph 9 of the settlement requires Consumers to use commercially reasonable efforts to maintain the 50/50 split between owned resources and PPAs for new solar procurements

[6] See for example Case No. U-20963, December 22, 2021 Order, pp. 402-403 (agreeing "that a COSS with a low-income customer subclass may be beneficial and recommends the company include a low-income customer subclass in the COSS for the EAAC in Case No. U-20757[.]"); Case No. U-20875, March 17, 2022 Order Approving Settlement Agreement.

that was first approved in the U-20165 settlement. This provision creates an absolute cap of 60% on capacity that Consumers acquires for ownership in any annual solicitation, while setting no cap on the amount of new solar the Company may acquire via PPA. The term also maintains the bar on Consumers affiliates participating in the PPA portion of the solicitations.

Q. In your opinion, is continuing the 50/50 split a reasonable and beneficial settlement term?

A. Yes. The Commission found this allocation reasonable and in the public interest in Case No. U-20165 and this term maintains the essential components of that agreement. It promotes competition among third-party developers which reduces customer costs, and it helps support the solar industry in Michigan. This term represents a substantial compromise by Consumers, which had sought in this case to eliminate a maximum amount of solar it could procure for Company ownership. This provision is also consistent with the PFD recommendation on this issue.

Q. What does the settlement provide regarding the Financial Compensation Mechanism?

A. The settlement provides at paragraph 10 for an extension of the FCM approved in Case No. U-20165. The method for calculating the FCM will remain the same as approved in that case, using after-tax WACC and total capital structure. The FCM will not be applied to PPA amendments, PURPA PPAs, Voluntary Green Pricing PPAs, or PPAs executed under Consumers' renewable energy plan.

Q. In your opinion, is the FCM a reasonable and beneficial settlement term?

A. Yes. Consumers has substantially changed its business model by agreeing to shift its resource portfolio away from coal generation and toward solar generation, and by agreeing to procure the solar generation via competitive solicitations under which half of that capacity will be in the form of PPAs. An FCM is a reasonable incentive for the Commission to authorize under such circumstances. I supported the FCM under these terms in both U-20165 and this case for those reasons. The Commission approved the FCM in Case No. U-20165 over vigorous objection of a small minority of parties, and the Commission's reasoning in that case applies equally in this one. Further, Consumers has compromised on the methodology for calculating the FCM by using after-tax WACC and total capital structure rather than pre-tax WACC and permanent capital structure as the Company requested in this case. The calculation methodology is also supported by my testimony in this case.

Q. What does the settlement provide regarding transmission analysis?

A. Paragraph 16 of the settlement states that the parties agree in Consumers' next IRP to consider how transmission investments can improve reliability and access to economic sources of power from areas outside Zone 7.

Q. In your opinion, is the transmission provision a reasonable and beneficial settlement term?

A. Yes. MNS witness Jay Caspary described the importance of transmission for both reliability and economics in his direct testimony in this case. The PFD found that

Consumers' transmission analysis in this case was deficient and did not meet the terms of the settlement agreement in U-21065. Consumers' commitment to address transmission analysis further in its next IRP will maintain focus on this issue going forward.

Q. What does the settlement provide regarding battery storage investments?

A. The parties agree to approval of a battery deployment program in paragraph 3 of the settlement agreement. Consumers proposed in rebuttal testimony to advance investment in 75 MW of battery storage resources. The settlement reserves approval of the costs of the program to future electric rate cases.

Q. In your opinion, is the battery storage program a reasonable and beneficial settlement term?

A. Yes. Consumers made the battery proposal in response to testimony from Staff, MNS, and other parties that called for acceleration of battery storage investments as part of Consumers' resource portfolio for this IRP. The battery deployment will provide another clean energy resource to bolster Consumers' maintenance of its PRMR and support resource adequacy in Zone 7. It is also worth noting that the clean energy tranche of the one-time solicitation (paragraph 6(b)(ii)) may similarly lead to the development of new battery storage resources within Zone 7.

Q. What does the settlement provide regarding collection and analysis of line loss data and avoided transmission and distribution costs in the evaluation of distributed resources?

A. Consumers agrees in paragraph 14 of the settlement to collect further data on marginal line losses and to include marginal line losses and avoided transmission and distribution (T&D) costs in the evaluation of all distributed resources, including residential demand response, for its next IRP.

Q. In your opinion, is the line loss and avoided T&D provision a reasonable and beneficial settlement term?

A. Yes. This term is based on recommendations by CUB witness David Gard and MNS witness Chris Neme. Both of these witnesses explained the importance of these issues to the evaluation of EWR potential and DR potential for future IRPs. Consumers agreed to some but not all of their recommendations in rebuttal testimony, and has reached further agreement via this settlement term.

Q. What does the settlement provide regarding environmental justice and community outreach?

A. Paragraphs 17 and 18 of the settlement contain detailed provisions regarding environmental justice analysis and community outreach for Consumers' next IRP.

Q. In your opinion, are the environmental justice and community outreach provisions reasonable and beneficial settlement terms?

A. Yes. The CEOs and Urban Core Collective sought measures like these in their testimony in this case. The environmental justice analysis will provide vital information regarding the people and communities who bear disproportionate impacts of electric generation activities – information that has been lacking in Michigan IRP cases up until now. The community outreach provisions are important steps toward facilitating greater awareness and participation by people and communities who are normally excluded by the nature of proceedings like these.

Q. What does the settlement provide regarding community transition plans for the Campbell and Karn sites?

A. Paragraph 7 of the settlement agreement requires Consumers to publicly file its community transition plans for the Campbell and Karn sites.

Q. In your opinion, is the community transition plans provision a reasonable and beneficial settlement term?

A. Yes. MNS witness Tyler Comings testified in this case regarding the need for these plans to be public.

IV. CONCLUSION AND RECOMMENDATIONS

Q. What is your overall conclusion regarding the settlement agreement?

A. The settlement agreement in this case continues and significantly extends the progress of the settlement in U-20165. The settlement approves a major step by Consumers to address

the climate crisis while providing numerous protections for customers from future costs and risks. It is comprehensive, detailed, thorough, and embodies the input of many parties to this case. It is supported by the great weight of the evidence in the record of this case and consistent with many of the findings and recommendations in the PFD. It is the product of extensive negotiations and represents reasonable compromises on many fronts. I recommend that the Commission approve it.

Q. Does that complete your testimony?

A. Yes.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-9

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

Exhibit 58

MISO Tariff Module E-1

This Module E-1 provides mandatory requirements to be met by the Transmission Provider, Market Participants serving Load in the Transmission Provider Region or serving Load on behalf of a Load Serving Entity (LSE), or other Market Participants, to ensure access to deliverable, reliable and adequate Planning Resources to meet Coincident Peak Demand and Local Resource Zone Peak Demand requirements on the Transmission System. These requirements recognize and are complementary to the reliability mechanisms of the states and the Regional Entities (RE) within the Transmission Provider Region. Nothing in this Module E-1 affects existing state jurisdiction over the construction of additional capacity or the authority of states to set and enforce compliance with standards for adequacy. The Resource Adequacy Requirements (RAR) in this Module E-1 are not intended to and shall not in any way affect state actions over entities under the states' jurisdiction. To the extent that an LSE's Coincident Peak Demand is physically located within the Transmission Provider's Balancing Authority Area but is pseudo-tied out of the MISO Balancing Authority Area pursuant to the Transmission Provider's Business Practices Manuals (BPM), such Coincident Peak Demand is not subject to the RAR provisions if such Coincident Peak Demand is subject to another Balancing Authority Area's resource adequacy requirements. To accomplish these reliability requirements, Module E-1 includes provisions for: establishing Local Resource Zones and associated limits (*i.e.*, Capacity Import Limits (CIL) and Capacity Export Limits (CEL)); establishing Local Reliability Requirements (LRR); establishing Local Clearing Requirements (LCR); establishing External Resource Zones and associated limits (i.e., Capacity Export Limits (CEL)); determining the Planning Reserve Margin; Coincident Peak Demand forecasting; Local Resource Zone Peak Demand forecasting; qualifying and quantifying Planning Resources; participation of Demand and Planning Resources in the Planning Resource

Auction process; settlement provisions; and Planning Resource performance requirements for each Season.

Establishment of Planning Reserve Margins

The Transmission Provider will determine a Planning Reserve Margin (PRM) in terms of Unforced Capacity for each Season using analytical study methods described in Section 68A.2, provided that if a State Regulatory Authority establishes a PRM for its regulated entities that is higher or lower than the PRM determined by the Transmission Provider, then the State Regulatory Authority-established PRM will apply to the Coincident Peak Demand of LSEs under that state's jurisdiction.

Planning Reserve Margin Analysis

The Transmission Provider shall perform a technical analysis on an annual basis to establish the PRM for each Season for the Transmission Provider Region and the Transmission Provider will publish the results by November 1 preceding the applicable Planning Year. The PRM analysis shall be consistent with Good Utility Practice and the reliability requirements of the REs and the applicable states in the Transmission Provider Region. The PRM analysis shall consider factors including, but not limited to: the Generator Forced Outage rates of Capacity Resources; Generator Planned Outages; expected performance of Demand Response Resources (DRR), Load Modifying Resources (LMR), and Energy Efficiency Resources; load forecast uncertainty; and the Transmission System's import and export capability with external systems. The Transmission Provider annually will calculate and publish on its website the estimated PRM for each of the nine subsequent Planning Years, to provide information for long-term resource planning, without establishing any enforceable specific planning reserve requirements.

Loss of Load Expectation Analysis

The Transmission Provider shall coordinate with Market Participants to determine the appropriate PRM for the applicable Season in the Planning Year based upon the probabilistic analysis of being able to reliably serve the Transmission Provider Region's Demand for the applicable Season in the Planning Year. This probabilistic analysis shall use a Loss of Load Expectation (LOLE) study which assumes that there are no internal transmission limitations within the Transmission Provider Region.

The following process will be utilized to determine the minimum PRM requirement for each Season in the Planning Year using the LOLE analysis. First, an LOLE analysis for the Planning Year will be conducted such that the LOLE for the Planning Year is one (1) day in ten (10) years, or 0.1 day per year, by either adding or removing capacity. If the LOLE for the Planning Year is less than 0.1 day per year, a perfect negative unit with zero forced outage rate will be added until the LOLE reaches 0.1 day per year. If the LOLE for the Planning Year is greater than 0.1 day per year, proxy units based on a unit of typical size and forced outage rate will be added to the model until the LOLE reaches 0.1 day per year. If the LOLE for a Season is equal to or greater than 0.01 day per year, the minimum PRM requirement for that Season will be calculated based on this LOLE analysis. If the LOLE for any Season is less than 0.01 day per year, an additional LOLE analysis will be performed to determine minimum PRM requirement for that Season by adding a perfect negative unit with zero forced outage rate to that Season until the LOLE in that Season reaches 0.01.

The minimum amount of capacity above Coincident Peak Demand in the Transmission Provider Region required to meet the reliability criteria will be used to establish the PRM for each Season.

The PRM will be established as a requirement in terms of the total Unforced Capacity for the Transmission Provider Region.

No later than September 1st of the year prior to a Planning Year, the Transmission Provider will, as necessary, develop new Local Resource Zones (LRZ) to reflect the need for an adequate amount of Planning Resources to be located in the right physical locations within the Transmission Provider Region to reliably meet Demand and LOLE requirements. The geographic boundaries of each of the LRZs will be based upon analysis that considers: (1) the electrical boundaries of Local Balancing Authorities; (2) state boundaries; (3) the relative strength of transmission interconnections between Local Balancing Authorities; (4) the results of LOLE studies; (5) the relative size of LRZs; and (6) natural geographic boundaries such as lakes and rivers. The Transmission Provider may re-evaluate the boundaries of LRZs if there are significant changes in the Transmission Provider Region based upon the preceding factors, including but not limited to, significant changes in membership, the Transmission System, and/or Resources.

An External Resource Zone (ERZ) will be created for each external Balancing Authority that has External Resources qualifying as Planning Resources, excluding those Balancing Authorities with only Coordinating Owner resources that are qualified to obtain local credit and/or Border External Resources.

Establishment of SRRZs, SRECs and SRICs

The Transmission Provider will establish and publish, on the Transmission Provider's public website, SRRZs, SRECs and SRICs for each Season as soon as practical but no later than the first business day of March for the following Planning Year. To calculate the SRECs and SRICs, the Transmission Provider will determine the transfer limit between SRRZs in accordance with applicable seams agreements, coordination agreements, or transmission service agreements. Next, the Transmission Provider will then complete a feasibility analysis in accordance with the Resource Adequacy Business Practices Manual to review operational events from each Coincident Peak Demand hour during the previous Planning Year, and forecasted expected conditions for each Season in the upcoming Planning Year, to determine if a further reduction to the transfer limit is warranted for reliability. If such a reduction is necessary, the Transmission Provider will reduce the regional directional transfer limit, as appropriate. The Transmission Provider will then subtract the sum of Firm Transmission Service Reservations on the MISO OASIS that utilize the contract path between SRRZs and are exporting from or wheeling through the Transmission Provider's Balancing Authority for the applicable Season in the Planning Year. This difference determines the SREC and SRIC to be utilized for the applicable Season in the Planning Year.

Prior to publishing the SRRZs, SRECs, and SRICs on its public website, Transmission Provider will present the feasibility analysis and resulting SREC and SRIC calculation to stakeholders.

Establishment of CIL and CEL Limits

On or before November 1st of each year, the Transmission Provider will determine preliminary values for the CIL and CEL for each of the LRZs for each Season in the following Planning Year by considering factors, including but not limited to, the following elements: (1) existing and planned Transmission System and Planning Resource additions; (2) transmission import and export capability; and (3) applicable NERC contingencies. To determine the CIL and CEL for each LRZ, the Transmission Provider will use models which contain the physical location of Load and Planning Resources for each Season. Generator output will be assigned to LRZs or ERZs consistent with the PRA representation of Planning Resources. Constraints that are identified as a result of determining the CIL and/or the CEL for each LRZ will be considered in the development of the MISO Transmission Expansion Plan (MTEP) in accordance with Attachment FF.

CIL will be equal to the Zonal Import Ability plus firm capacity commitments to non-MISO load. CEL will be equal to the Zonal Export Ability minus firm capacity commitments to non-MISO load.

The CIL and CEL values for each Season for each LRZ will be updated if needed prior to the Planning Resource Auction, but no later than eight (8) Business Days before the last Business Day in March, due to changes to firm capacity commitments from MISO resources to neighboring regions prior to the Planning Resource Auction.

MISO will determine the CEL for each Season for each ERZ no later than eight (8) Business Days before the last Business Day in March as equal to the ZRC quantity of the External Resources registered to participate in the PRA.

Establishment of Local Reliability Requirement

By November 1st prior to a Planning Year, the Transmission Provider will establish a Local Reliability Requirement (LRR) metric for each LRZ to determine the quantity of Unforced Capacity needed for each Season, without consideration of the benefit of the LRZ's CIL. First, the LOLE analysis for the Planning Year will be conducted by either adding or removing capacity until the LOLE reaches 0.1 day per year for the LRZ. If the LOLE for the Planning Year is less than 0.1 day per year, a perfect negative unit with zero forced outage rate will be added until the LOLE reaches 0.1 day per year. If the LOLE for the Planning Year is greater than 0.1 day per year, proxy units based on a unit of typical size and forced outage rate will be added to the model until the LOLE reaches 0.1 day per year. If the LOLE for a Season is equal to or greater than 0.01 day per year for the LRZ, the LRR for that Season will be calculated based on this LOLE analysis. If the LOLE for any Season is less than 0.01 day per year for the LRZ, an additional LOLE analysis will be performed to determine the LRR for that Season by adding a perfect negative unit with zero forced outage rate to that season until the LOLE in that Season reaches 0.01 day per year for the LRZ.

The Transmission Provider will model the location of Load and Planning Resources based on their representation in the Planning Resource Auction to determine the LRR for each LRZ. The minimum amount of capacity above the Local Resource Zone Peak Demand in the LRZ required to meet the reliability criteria will be used to establish the LRR for each Season.

The per unit LRR in each LRZ initially will be established as the ratio of the LRR over the Local Resource Zone Peak Demand modeled in the LOLE study. An LRZ's LRR shall be calculated by multiplying the per unit LRR for the LRZ times the forecasted Local Resource Zone Peak

Demand for each Season as provided by LSEs or EDCs, or as developed by the Transmission Provider, pursuant to Section 69A.1.

Establishment of Local Clearing Requirement

The Local Clearing Requirement for each LRZ for each Season will be determined by subtracting Zonal Import Ability and controllable exports from the LRR, as set forth in the Resource Adequacy Business Practices Manual. Controllable exports are exports from MISO resources that have firm capacity commitments to non-MISO load and that may be committed and dispatched by the Transmission Provider during a declared Energy Emergency. The LCR values will be updated if needed prior to the Planning Resource Auction due to changes in controllable exports.

Establishing Planning Reserve Margin Requirements

a. The Transmission Provider will establish Planning Reserve Margin Requirements (PRMR) for each Season for an LSE's Load within any given LRZ. The Initial PRMR will be determined by multiplying the LSE's forecasted Coincident Peak Demand for each Season, including transmission losses, by (1 + Transmission Provider Region PRM).

b. The Transmission Provider will use the Transmission Provider Region PRM for the Initial PRMR calculation unless an alternate PRM is established by a State Regulatory Authority. In such event, the Transmission Provider will use the alternate PRM that a State Regulatory Authority has created for the geographic area in which the state has jurisdiction. The Transmission Provider will convert any State Regulatory Authority provided PRM to a comparable Unforced Capacity basis.

Calculation of Transmission Losses

a. The Transmission Provider shall calculate the LBA transmission loss percentages for each Season using the process described as follows:

1. The Transmission Provider's State Estimator calculates transmission losses (MW) as part of the solution output process every five (5) minutes.
2. The transmission losses (MW) are computed on all transmission lines and transformers by summing up real power at both ends for each transmission element (retaining the convention for flow direction) or as the difference in real power (without the sign convention for flow direction) for each State Estimator solution.
3. The individual transmission losses (MW) for each element are summed to a total transmission values for each Local Balancing Authorities (LBA) level.
4. These LBA transmission loss values are then integrated across each hour to calculate an hourly transmission loss value (MW) for each LBA.
5. The total transmission loss value (MW) for each LBA will be the hourly integrated transmission losses value (MW) for the hour of the Coincident Peak Demand from the calendar year two years prior to the upcoming Planning Year.
6. For the purposes of the Transmission Provider Region, the LBA transmission loss percentages are calculated as the total LBA transmission losses divided by the total LBA peak data at that MISO peak hour for each Season. For purposes of a Local Resource Zone, the LBA transmission loss percentages are calculated as the

total LBA transmission losses divided by the total LBA peak data at the LRZ peak hour for each Season.

b. The Local Balancing Authority (LBA) transmission loss percentage shall apply to the LSE's applicable LBA Coincident Peak Demand and Local Resource Zone Peak Demand forecast to determine the LSE transmission losses. Behind-the-Meter-Generation Resources that are interconnected to the Transmission System shall be treated like other Resources with respect to transmission losses. Behind-the-Meter-Generation Resources and Distributed Energy Aggregated Resources that are not interconnected to the Transmission System, Demand Resources, and Energy Efficiency Resources shall be adjusted to account for serving load without incurring transmission losses by grossing up the MW quantity of such resources by (1.0 + the appropriate LBA transmission loss percentage).

Marginal Reliability Impact (MRI) Curves

A. The following process will be used to determine the MRI Curves for the Transmission Provider Region for each Season of the upcoming Planning Year. The minimum PRM requirement for each Season established in the LOLE analysis, as described in Section 68A.2, will be the starting point. Then, for each Season, a perfect negative unit(s) with a capacity of at least 50MW and no more than 250MW, or perfect proxy unit(s) with a capacity of at least 50MW and no more than 250MW will be added to the model and the LOLE analysis will be performed. The capacity of both the perfect negative unit(s) and perfect proxy unit(s) will be of equal value. The change in EUE as a result of adding or removing capacity will be calculated. An additional unit(s) with the same capacity value will be added or removed in addition to the first increment or decrement and the LOLE analysis will be performed again. This process will be repeated until sufficient data is available to fit a curve that measures changes to EUE as MWs are added or removed from the minimum PRM requirement.

B. The First Planning Area MRI Curve is a smoothed representation of reliability changes as measured by EUE as more or less MWs are included in the LOLE analysis. The following process will be used to determine the MRI Curves for the First Planning Area for each Season in the Planning Year. Assignment of LOLE risk across the Seasons will be the same as described in Section 68A.2 for the Planning Reserve Margin analysis. A minimum PRM requirement for the First Planning Area for each Season will be established through additional LOLE analysis in which the First Planning Area and Second Planning Area each have the same reliability target established for the

Transmission Provider Region as the starting point. After establishing the starting point, the MW quantity associated with the minimum PRM requirement in the Second Planning Area will be fixed, and capacity in the First Planning Area will then be added or removed to calculate changes to EUE in the First Planning Area.

C. The Second Planning Area MRI curve is a smoothed representation of reliability changes as measured by EUE as more or less MWs are included in the LOLE analysis. The following process will be used to determine the MRI Curves for the Second Planning Area for each Season in the Planning Year. Assignment of LOLE risk across the Seasons will be the same as described in Section 68A.2 for the Planning Reserve Margin analysis. A minimum PRM requirement for the Second Planning Area for each Season will be established through additional LOLE analysis in which the First Planning Area and Second Planning Area each have the same reliability target established for the Transmission Provider Region as the starting point. After establishing the starting point, the MW quantity associated with the minimum PRM requirement in the First Planning Area will be fixed, and capacity in the Second Planning Area will then be added or removed to calculate changes to EUE in the Second Planning Area.

RAR Process

Once the Transmission Provider has established the PRM, LCR, LRR, preliminary Capacity Import Limits and Capacity Export Limits and published such values on the Transmission Provider's website, then LSEs shall provide forecasted Coincident Peak Demand and Local Resource Zone Peak Demand data for the Planning Year. For Retail Choice areas, the EDC shall provide, on behalf of LSEs within the EDC, forecasted Coincident Peak Demand and Local Resource Zone Peak Demand data for the Planning Year to be used by the Transmission Provider. The Transmission Provider will then calculate each LSE's Initial PRMR for each Season. LSEs will meet their RAR obligation by: (i) submitting a Fixed Resource Adequacy Plan; (ii) submitting ZRCs for an RBDC Opt Out; (iii) Self-Scheduling ZRCs; (iv) purchasing ZRCs through the Planning Resource Auction process; and/or (v) paying the Capacity Deficiency Charge to meet a portion of their PRMR. LSEs that submit an RBDC Opt Out may not use any of the other options to satisfy their Final PRMR. LSEs not submitting an RBDC Opt Out may use one or more of all other available options, or any combination of available options, to satisfy their Initial or Final PRMR. The Transmission Provider will enforce the LCRs, final Capacity Import Limits and Capacity Export Limits for each LRZ, and Capacity Export Limits for each ERZ in the Planning Resource Auction. An ACP will be determined through the PRA process for each LRZ and ERZ for each Season and the ACP will be used to credit ZRCs that clear in the auction and to debit LSEs for the volume of their PRMR that is procured through the auction. Market Participants that own Planning Resources used to create ZRCs which clear in the PRA (or are identified in either a submitted Fixed Resource Adequacy Plan or an RBDC Opt Out) must meet the applicable performance requirements as described in sections 69A.3.9 and

69A.5. The Transmission Provider shall provide states, upon request, with relevant resource adequacy information as available, subject to the data confidentiality provisions in Section 38.9 of the Tariff.

Load Serving Entity Responsibilities

a. LSEs shall provide Coincident Peak Demand (and also, if available, Local Resource Zone Peak Demand forecasts) forecasts as specified in Section 69A.1.1b and will also be responsible for meeting their Final PRMR for each LRZ where they serve Load by submitting Fixed Resource Adequacy Plans, by Self-Scheduling ZRCs, by purchasing ZRCs through the PRA process, by submitting ZRCs for an RBDC Opt Out and/or by paying the Capacity Deficiency Charge.

b. The Transmission Provider will use Coincident Peak Demand, Local Resource Zone Peak Demand, and Energy forecasts for each Season that are submitted by an EDC in combination with allocation procedures that are agreed to by the applicable LSEs. These procedures will allow the Transmission Provider to initially allocate appropriate portions of the total forecasted Coincident Peak Demand and Local Resource Zone Peak Demand to each LSE as applicable pursuant to 69A.1.2.1, and to re-assign ZRC-related charges caused by customer switching between suppliers to the appropriate LSE.

c. All LSEs shall report to the Transmission Provider, through the MECT, whether such LSE will meet their PRMR for each LRZ for each Season in which the LSE serves Load by: (i) submitting a Fixed Resource Adequacy Plan; (ii) Self-Scheduling ZRCs; (iii) purchasing ZRCs through the Planning Resource Auction process; (iv) submitting an RBDC Opt Out; and/or, (v) paying the Capacity Deficiency Charge.

Forecasted Demand Identification

a. The Demand forecasts required in Section 69A.1 shall include: (1) the Coincident Peak Demand within each LBA Area in the Transmission Provider Region for the upcoming Planning Year; (2) the monthly non-coincident peak Demand and net Energy for Load within each LBA Area, for the upcoming Planning Year and the following Planning Year; (3) the non-coincident peak Demand and net Energy for Load within each LBA Area, for each Season, for the eight Planning Years subsequent to the two for which monthly values are provided in (2); and (4) the available Local Resource Zone Peak Demand within each LBA Area in the Local Resource Zone for the upcoming Planning Year. All of these forecasts shall be submitted by November 1st prior to each Planning Year and shall be consistent with Good Utility Practice. Forecast providers shall use the MECT or other means described in the BPM for Resource Adequacy to submit the requisite information. Details regarding the items required in the Demand forecasts submittal are in the BPM for Resource Adequacy.

b. The supplied Coincident Peak Demand and Local Resource Zone Peak Demand forecasts shall include the Demand expected for the forecast time period (*e.g.* the Coincident Peak Demand hour) augmented to include the normal Demand from forecasted demand resources, whether registered or not registered with the Transmission Provider, including Demand from any retail demand side management programs and Demand behind a DEAR. Such forecasts shall include Demand that would have occurred but for the existence of Energy Efficiency Resources that have been in operation less than four (4) years. All submissions for such forecast values shall include distribution losses, but not transmission losses. The Transmission Provider will be responsible for the calculation of the applicable transmission losses for the forecasts provided

and for annually publishing such values for each LBA on its website by October 1, as specified in Section 68A.8 and the BPM for Resource Adequacy.

c. In order to assist with the development of the Coincident Peak Demand and Local Resource Zone Peak Demand forecasts, the Transmission Provider will make available the historical monthly peak hours for each of the four months June through September, since 2005, or as available, for the Transmission Provider Region and for each Local Resource Zone. On or before March 1st of each year, the Transmission Provider will review a sampling of submitted Demand forecast methodologies and inputs to ensure accuracy and consistency, in accordance with the BPM for Resource Adequacy. If the Transmission Provider determines that the Demand forecast methodologies are inaccurate or inconsistent, the Transmission Provider shall work with the applicable LSEs to reconcile such issues. If reconciliation is not achieved, or if Local Resource Zone Peak Demand forecasts are not available, then the Transmission Provider will provide the required forecast values.

d. All Coincident Peak Demand and Local Resource Zone Peak Demand forecasts shall reflect a 50% probability that the Demand will not exceed the forecasted Demand for the relevant period.

e. Consistent with Section 69A.1.2.1, the EDC must provide both the Transmission Provider and the respective LSEs with each retail customer's peak load contribution ("PLC") in each Season, including transmission losses and PRM as determined by the Transmission Provider, in the EDC's service territory by December 15th. At least five (5) Business Days before January 15, LSEs must notify the EDC and the Transmission Provider if they disagree with the EDC calculated PLC value.

f. If an LSE knows it will gain a wholesale customer by the beginning of any Season in the next Planning Year, then that LSE may provide the Transmission Provider with the Coincident Peak Demand and the Local Resource Zone Peak Demand forecast for such acquired load by November 1. In all other cases, the existing Market Participant serving such wholesale customer shall provide the Transmission Provider by November 1st with the Market Participant's forecast of the wholesale customer's Coincident Peak Demand and Local Resource Zone Peak Demand.

Accounting for Total Demand Forecasts Given Wholesale and Retail Load Switching

a. On or before January 15th, an EDC must notify the Transmission Provider through the MECT of the Initial PRMR for the LSE's proportion of the EDC's forecast Demand that it expects to serve on the 1st day of each Season in the next Planning Year. The LSE that is the provider of last resort ("POLR") for the EDC area in question will have the obligation to procure capacity for the required PRMR for the remaining Demand (*i.e.*, the remaining Demand is the EDC's forecast Coincident Peak Demand minus the sum of the LSE's allocated portion of forecast Coincident Peak Demand, identified as described above, in the EDC's service territory). The Transmission Provider will notify the POLRs of any remaining Initial PRMR within five (5) Business Days after January 15th.

b. On or before January 15th, to account for wholesale customers that may switch LSEs during the next Planning Year, the PRMR will be met as follows: (1) if an LSE has responsibility to serve a wholesale load on the 1st day of any Season in of the next Planning Year, then such LSE shall have the obligation to procure the required PRMR for such load for such Season; (2) if no LSE has responsibility for serving a wholesale load on of the 1st day of any Season in of the next Planning Year, then the LSE with an obligation to serve such load on November 1 before the Planning Year, shall have the obligation to procure capacity for the required PRMR for each Season in the upcoming Planning Year for such load, provided that such LSE anticipates that the contract for wholesale load will be extended; or (3) if the LSE advises the Transmission Provider that the LSE will not serve the contract for wholesale load, then the customer for such wholesale load shall inform the Transmission Provider by January

30th of the name of the Market Participant that will be responsible for the PRMR obligation for such wholesale load.

Daily Assignment of Coincident Peak Demand Obligations

a. For those areas of service where an LSE's Coincident Peak Demand forecast is included in the Coincident Peak Demand forecast submission of an EDC, the EDC will determine and report each LSE's portion of such Demand to the Transmission Provider, using the default method set forth in Section 69A.1.2.1.

b. In a state that permits retail load switching, the Transmission Provider shall allocate resource capacity costs on a daily basis to LSEs by multiplying the Final PRMR associated with identified customers served by the LSE times the applicable zonal Auction Clearing Price less any zonal deliverability benefits plus any Local Clearing Requirement Charges for the Local Resource Zone where the load is located, consistent with Section 69A.1.2.1.

c. In states where wholesale load may switch, the Transmission Provider shall allocate costs on a daily basis to LSEs. The LSE that acquires wholesale load will be charged for such load based upon the Final PRMR for the wholesale load's forecast Coincident Peak Demand times the applicable zonal Auction Clearing Price less any zonal deliverability benefits plus any Local Clearing Requirement Charges for the Local Resource Zone where the wholesale load is located.

d. An LSE may challenge the EDC Demand forecast under the dispute resolution procedures pursuant to Section 12 or it may refer the dispute to the Commission for resolution.

Default Method

a. The method submitted by an EDC must describe in detail the procedures and data used to determine the assignment of the EDC's forecast Coincident Peak Demand to its retail customers, including those served by LSEs providing service within the EDC's area.

b. EDC will assign a peak load contribution ("PLC") value to each retail customer, based on the most recent PLC values derived for each Season from each retail customer's Demand at the time of the Transmission Provider's peak Demand during each Season (*i.e.*, the Prior Seasonal Retail Customer Coincident Peak ("PSRCCP")). Retail customer peak demands should be increased to reflect any load reductions achieved and for which capacity credits are earned, either through retail programs or participation in wholesale markets (*e.g.* LMRs). In the aggregate, the PLCs determined by the EDC must equal the Initial PRMR that is calculated from the forecast Coincident Peak Demand provided by the EDC for each Season. This equality is achieved by multiplying each retail customer's demand at the time of the Transmission Provider's peak Demand during each Season prior to the Planning Year by the same adjustment factor, as shown in the equation below:

$$\Sigma_i \, PLC_i = \text{Initial } PRMR_{EDC}$$

$$\text{Factor} = \text{Initial } PRMR_{EDC} \div \Sigma_i \, PSRCCP_i$$

In other words, for each EDC, the sum of the individual retail customer (*i.e.*, i) PLC values must equal the EDC's Initial PRMR. In addition, a single value ("Factor") is defined as the ratio of the Initial PRMR for any EDC divided by the sum of all of the PSRCCP values for each of the EDC's retail customers. The EDC must use the same Factor in the following equation:

$$PLC_i = \text{Factor} \times PSRCCP_i \quad \forall i$$

Thus, for each EDC it must also be true that the PLC for any individual retail customer shall be equal to the product of that customer's PSRCCP times the same Factor identified in the second equation above. For the purposes of these equations, the following mathematical symbols are used: (1) Σ equals sum; (2) $_i$ equals individual retail customer, as in PLC $_i$ or PSRCCP$_i$; and (3) ∀i equals for all i, as in: for each member of the set of retail customers.

c. The PSRCCP shall be adjusted (upward) to reflect any demand that was reduced during the Coincident Peak for each Season hour through the effect of a Load Modifying Resource, or through the effect of an Energy Efficiency Resource during the first four (4) full Planning Years of the EE Resource's existence. The Transmission Provider will provide to the EDC the amount of measured (or estimated if final settlement data is forthcoming) load reduction that occurred as a result of an ARC or LSE deploying a DRR, LMR or EDR following a Setpoint Instruction, Scheduling Instruction or EDR Dispatch Instruction during the Transmission Provider's Coincident Peak Demand.

Load Switching

Beginning the first Calendar Day of each Season in the Planning Year, the EDC will be responsible for tracking the individual customer Final PRMR values transferred from the originally supplying LSE to the newly supplying LSE now responsible for resource adequacy commitments.

Forecasted Demand for FRP/FRS Agreements

Full Responsibility Purchases/Sales (FRP/FRS) agreements are treated effectively like a transfer of Demand and all RAR obligations from one LSE to another Market Participant. A purchaser under an FRP/FRS agreement shall submit the forecasted Coincident Peak Demand and Local Resource Zone Peak Demand associated with such agreement to the Transmission Provider through the MECT for the applicable Planning Year. A seller under an FRP/FRS agreement is contractually obligated to comply with all of the RAR obligations for the transferred Demand during the Planning Year encompassing the planned Coincident Peak Demand. The purchaser under an FRP/FRS agreement no longer has the RAR obligations for the transferred Demand; provided however, that if the seller under an FRP/FRS agreement is not an LSE under the jurisdiction of the Transmission Provider, then the purchaser under the FRP/FRS agreement will remain responsible for any RAR obligations associated with the Demand transferred under the FRP/FRS agreement. A seller under an FRP/FRS agreement will be responsible for the transferred Demand to meet this additional obligation like it was their own Demand. If a seller and a purchaser under an FRP/FRS agreement cannot agree on whether a particular transaction is an FRP/FRS agreement, then either party may invoke the dispute resolution procedures in Section 12 of the Tariff.

Multiple Region Planning Resources

If an LSE serves Demand both in the Transmission Provider Region and outside the Transmission Provider Region, then the LSE must separately satisfy its Final PRMR in all areas of the Transmission Provider Region. Compliance with RAR shall not affect an LSE's obligation to maintain distinct and separate amounts of resources to cover its applicable planning reserve obligation for the amount of Demand outside the Transmission Provider Region.

Capacity Tracking Tool

To facilitate RAR, the Transmission Provider shall administer the MECT, a title tracking and registration tool that shall include the ability to enable Market Participants and LSEs to meet their RAR responsibilities.

Planning Resource Requirements

Nothing herein shall infringe upon the requirement that LSEs comply with applicable state safety standards, planning reserve margins, or be subject to the enforcement thereof. If the Transmission Provider becomes aware that any Planning Resource fails to meet the requirements of this section, then the Transmission Provider shall promptly notify the Market Participant and specify the reasons for any such failure. Wherever possible, the Transmission Provider and the Market Participant will work in good faith to remedy deficiencies, if any, in meeting the Planning Resource requirements, through informal communications rather than Commission filings.

Capacity Resources

As described below, a Generation Resource, External Resource, Demand Response Resource - Type II, Intermittent Generation, Dispatchable Intermittent Resource, Electric Storage Resource, or Hybrid Resource is eligible to become a Capacity Resource. The Transmission Provider will qualify a Capacity Resource for any applicable Season in the upcoming Planning Year, in accordance with processes specified in the BPM for Resource Adequacy. Electric Storage Resources can be Capacity Resources if they meet all the requirements as specified in the BPM for Resource Adequacy, including the requirement to be able to continuously discharge for a minimum set of four (4) consecutive operating Hours across the Transmission Provider's coincident peak for each day, in accordance with the BPM for Resource Adequacy, provided that an Electric Storage Resource may de-rate its capacity in order to comply with this requirement.

Generation Resources that are not Dispatchable Intermittent Resources or Distributed Energy Aggregated Resources

1. Generation Resources and Electric Storage Resources that are not Dispatchable Intermittent Resources or Distributed Energy Aggregated Resources are eligible to qualify as Capacity Resources by a Market Participant that possesses ownership or equivalent contractual rights for the Resource by:

   (a) registering such resource with the Transmission Provider as documented in the BPM for Market Registration;

   (b) demonstrating GVTC capability for each Season in the Planning Year as established in the BPM for Resource Adequacy;

   (c) submitting generator availability data (including, but not limited to, NERC Generation Availability Data System (GADS) information) into a database provided by the Transmission Provider and as established in the BPM for Resource Adequacy;

   (d) by submitting the GVTC results to the Transmission Provider no later than October 31 prior to such Planning Year for existing Capacity Resources unless the Transmission Provider has granted an extension pursuant to Section 69A.3.1.a.4; and

   (e) demonstrating deliverability as described in Section 69A.3.1(g). All new Generation Resources and Electric Storage Resources that are not Dispatchable Intermittent Resources and Distributed Energy Aggregated Resources, or an existing Generation Resource and Electric Storage Resource that is not a Dispatchable Intermittent Resource and s Distributed Energy Aggregated Resource that has an increased installed capacity, shall submit their GVTC to the Transmission Provider prior to qualification, but no later

than March 1 prior to the PRA, as established in the BPM for Resource Adequacy.

2. Installed Capacity (ICAP) Deferral

If a Market Participant for a Generation Resource and Electric Storage Resource that is not a Dispatchable Intermittent Resource (including a Generation Resource and Electric Storage Resource that has the status of Suspend pursuant to Section 38.2.7) and a Distributed Energy Aggregated Resource that has not completed GVTC testing by the deadlines provided in 69A.3.1.a.1, is not expected to demonstrate deliverability, or is otherwise not expected to demonstrate commercial operation prior to March 1, ZRCs from such capacity may be used in the PRA or in a FRAP (including through bilateral ZRC transactions), subject to the notification, credit, and non-compliance provisions of Section 69A.7.9.

3. Reporting generator availability data based on GVTC is not required for a Generation Resource or Electric Storage Resource that is not a Dispatchable Intermittent Resource and a Distributed Energy Aggregated Resource and that is less than 10 MW if the Market Participant has never provided such data for such Resource. A Market Participant that begins reporting generator availability data based on GVTC for a Generation Resource or Electric Storage Resource that is not a Dispatchable Intermittent Resource and that is less than 10 MW must continue to report such data. A Generation Resource or Electric Storage Resource that has provisional Interconnection Service does not qualify as a Capacity Resource.

4. A Market Participant for a Generation Resource required to submit GVTC results must use Reasonable Efforts to submit GVTC by October 31 prior to the upcoming Planning

Year. If circumstances prevent the Market Participant from submitting the GVTC results for the Generation Resource by October 31, the Market Participant must notify the Transmission Provider no later than five (5) Business Days after October 31 and request an extension. The extension request must include a reasonable explanation and justification for missing the deadline and an expected completion date prior to the upcoming Planning Year. The Transmission Provider will review each extension request on a case by case basis to determine whether or not to approve or deny the request to extend the GVTC deadline. Denial of an extension will not preclude the Market Participant for the Generation Resource from utilizing the ICAP Deferral process as described in Section 69A.7.9.

Demand Response Resources – Type II

1. Demand Response Resources – Type II backed by a Demand Resource are eligible to qualify as Capacity Resources. A Market Participant that possesses ownership or equivalent contractual rights in the DRR – Type II can register such resource as a Capacity Resource with the Transmission Provider for the upcoming Planning Year as documented in the BPM for Market Registration and by meeting the following requirements:
    a. For an existing DRR – Type II that is a Capacity Resource, the Market Participant shall demonstrate capability and availability to reduce Demand in response to instructions from the Transmission Provider for each applicable Season and shall submit such data to the Transmission Provider no later than October 31 prior to such Planning Year unless the Transmission Provider has granted an extension, as established in the BPM for Resource Adequacy.
    b. For a new DRR – Type II or for an existing DRR – Type II that has experienced an increase in its Capacity Rating, and that is backed by a Demand Resource, the Market Participant shall submit test data to the Transmission Provider prior to qualification, but no later than March 1 prior to the PRA, as established in the BPM for Resource Adequacy.
2. A Demand Response Resource – Type II that is backed by behind the meter generation is eligible to qualify as Capacity Resources. A Market Participant that possesses ownership or equivalent contractual rights in the DRR – Type II can register such resource as a Capacity Resource with the Transmission Provider for the upcoming Planning Year as

documented in the BPM for Market Registration and by meeting the following requirements:

a. A Market Participant shall demonstrate GVTC capability of the DRR – Type II backed by behind the meter generation for each Season in the Planning Year as established in the BPM for Resource Adequacy;

b. An existing DRR – Type II backed by behind the meter generation shall submit GVTC results to the Transmission Provider no later than October 31 prior to such Planning Year unless the Transmission Provider has granted an extension pursuant to Section 69A.3.1.b.4; and

c. A Market Participant shall submit generator availability data (including, but not limited to, NERC Generation Availability Data System information) for the DRR – Type II backed by behind the meter generation into a database provided by the Transmission Provider.

d. For a new DRR – Type II or an existing DRR – Type II that has an increased installed capacity, and that is backed by behind the meter generation, the Market Participant shall submit GVTC data to the Transmission Provider prior to qualification, but no later than March 1 prior to the PRA, as established in the BPM for Resource Adequacy.

3. Installed Capacity (ICAP) Deferral

If a Market Participant for a DRR – Type II has not completed GVTC testing by the deadlines provided in 69A.3.1.b.2, is not expected to demonstrate deliverability, or is otherwise not expected to demonstrate commercial operation prior to March 1, ZRCs

from such capacity may be used in the PRA, in a FRAP (including through bilateral ZRC transactions), or in an RBDC Opt Out (including through bilateral ZRC transactions) subject to the notification, credit, and non-compliance provisions of Section 69A.7.9.

4. Reporting generator availability data based on GVTC is not required for a DRR – Type II backed by behind the meter generation facility of less than 10 MW if the Market Participant has never provided such data for such behind the meter generation facility. A Market Participant that begins reporting generator availability data for behind the meter generation facility that is less than 10 MW based on GVTC must continue to report such data. A Demand Response Resource – Type II that has provisional Interconnection Service does not qualify as a Capacity Resource. In accordance with the qualification provisions in the BPM for Resource Adequacy, the Transmission Provider will qualify a Demand Response Resource – Type II for the applicable Season in the upcoming Planning Year.
5. A Market Participant for a DRR – Type II required to submit GVTC results must use Reasonable Efforts to submit GVTC by October 31 prior to the upcoming Planning Year. If circumstances prevent the Market Participant from submitting the GVTC results for the DRR by October 31, the Market Participant must notify the Transmission Provider no later than five (5) Business Days after October 31 and request an extension. The extension request must include a reasonable explanation and justification for missing the deadline and an expected completion date prior to the upcoming Planning Year. The Transmission Provider will review each extension request on a case by case basis to determine whether or not to approve or deny the request to extend the GVTC deadline.

Denial of an extension will not preclude the Market Participant for the DRR – Type II from utilizing the ICAP Deferral process as described in Section 69A.7.9.

External Resources:

1. External Resources, including those specified in Diversity Contracts and PPAs (which are subject to additional qualification requirements in section 69A.3.1.c.4), are eligible to qualify as Capacity Resources by a Market Participant that possesses ownership or equivalent contractual rights in External Resources by: (a) registering such resources with the Transmission Provider as documented in the BPM for Resource Adequacy; (b) demonstrating GVTC capability for each Season that the resource will be registered in as established in the BPM for Resource Adequacy by providing operational data, and by submitting the GVTC results to the Transmission Provider no later than October 31 prior to such Planning Year for existing Capacity Resources unless the Transmission Provider has granted an extension pursuant to Section 69A.3.1.c.5; (c) submitting generator availability data (including, but not limited to, NERC Generation Availability Data System information) into a database provided by the Transmission Provider and as established in the BPM for Resource Adequacy; (d) identifying one or more specific External Resource(s) that can be verified by the Transmission Provider as Capacity Resource(s) and which does not include any portion(s) of an External Resource that has already qualified as a Capacity Resource; (e) demonstrating that there is firm transmission service for each Season that the resource is to be registered in from the External Resource to the border interface CPNode of the Transmission Provider Region and either that firm Transmission Service has been obtained to deliver capacity on the Transmission System from the border to a Load within an LRZ or demonstrating deliverability as described in Section 69A.3.1.g; and (f) certifying that any External

Resources being identified are not otherwise being used as capacity resources in any other RTO/ISO, in another resource adequacy construct, or in an external balancing authority's resource plan for its firm end-use load and capacity sales requirements within the external balancing authority area.

2. Installed Capacity (ICAP) Deferral

If a Market Participant for an External Resource has not completed GVTC testing by the deadlines provided in 69A.3.1.c.1, is not expected to demonstrate deliverability, or is otherwise not expected to demonstrate commercial operation prior to March 1, ZRCs from such capacity may be used in the PRA, in a FRAP (including through bilateral ZRC transactions), or in an RBDC Opt Out (including through bilateral ZRC transactions) subject to the notification, credit, and non-compliance provisions of Section 69A.7.9.

3. Reporting generator availability data for an External Resource of less than 10 MW based upon GVTC is not required if the Market Participant has never provided such data for such External Resource. A Market Participant that begins reporting generator availability data for an External Resource that is less than 10 MW based on GVTC must continue to report such data. All new External Resources or an existing External Resource that has an increased installed capacity shall submit their GVTC to the Transmission Provider prior to qualification as established in the BPM for Resource Adequacy. In accordance with the qualification provisions in the BPM for Resource Adequacy, the Transmission Provider will qualify an External Resource for the applicable Season in the upcoming Planning Year.

4. In the case of a power purchase agreement (PPA), including, but not limited to a Diversity Contract, then the agreement shall meet the additional qualification requirements set forth below:

   i. A PPA that does not identify the full Installed Capacity of the External Resource from which power will be supplied must specify the portions of each such External Resource that is available under the PPA (i.e. slice-of-system resources) and that are verifiable by the Transmission Provider. Each External Resource specified in such PPA must meet the criteria for a Capacity Resource for all of the portion of the contract amount assigned to the External Resource(s). The capacity from the External Resource will be reduced proportionately to remove amounts that fail to meet such criteria.

   ii. A copy of every PPA must be provided by the Market Participant using External Resources from such PPA as a Capacity Resource to the Transmission Provider to enable it to verify the External Resource(s) that are backing the PPA and to confirm compliance with RAR. Any redacted versions of a PPA submitted by a Market Participant must contain sufficient information to allow the Transmission Provider to verify compliance with RAR. The Transmission Provider will maintain the confidentiality of these agreements in accordance with the confidentiality provisions in Section 38.9 of the Tariff.

   iii. For PPAs executed after April 3, 2014, one of the following must apply regarding the external balancing authority in which the External Resource is located:

(a) In the case of unit specific sales, if the MISO Balancing Authority Area is experiencing an Energy Emergency, the external balancing authority will not interrupt the PPA Schedule from the External Resource unless the generator being used to serve the unit specific sale has a forced outage.

(b) In the case of slice-of-system sales, if the external balancing authority area experiences an Energy Emergency and the MISO Balancing Authority Area is simultaneously experiencing an Energy Emergency, the external balancing authority will only interrupt the PPA Schedule on a pro rata basis with the shedding of firm end-use load in the external balancing authority area. Pro rata interruption of the PPA Schedule from the External Resource will be determined as the ratio of the PPA Schedule to the sum of the external balancing authority firm end-use load plus the PPA Schedule. (c) If the external balancing authority (1) is located within the Transmission Provider's reliability coordinator area; (2) participates in a contingency reserve sharing group with the Transmission Provider; and (3) has a Seams Operating Agreement with the Transmission Provider containing the following features, then in the event that the external balancing authority area experiences an Energy Emergency and the MISO Balancing Authority Area is simultaneously experiencing an Energy Emergency, the Transmission Provider and the external balancing authority will share interruption of PPA Schedules from an External Resource and load shedding in the external balancing authority area on a pro rata basis in proportion to the end-use load in the area under the Energy Emergency. Pro rata sharing shall be

determined as the respective ratio of each of the balancing authority's end-use load in the Energy Emergency Area divided by the sum of the end-use load of each balancing authority in the Energy Emergency Area. The Seams Operating Agreement must (1) ensure that the external balancing authority has established a planning reserve margin and qualifications for planning resources using processes and criteria comparable to the Transmission Provider; (2) specify the actions that will be taken by both entities during an Energy Emergency prior to implementing firm end-use load shedding, and (3) specify that the external balancing authority will submit end-use load estimates to the Transmission Provider in a comparable manner as submitted by Load entities in Module E-1, provide generator GVTC and GADS data for all resources used to serve firm requirements of the external balancing authority, and provide transparency in the form of submittal of fixed resource plans comparable to processes used by Market Participants for Fixed Resource Adequacy Plans in the Transmission Provider's Module E-1.

iv. A PPA executed prior to April 3, 2014 will continue to qualify as a Planning Resource for the full term of the PPA if it is only interruptible as a last resort under Requirement 2 of NERC Standard EOP-011-1. A Diversity Contract executed prior to April 3, 2014 will continue to qualify as a Planning Resource, if it is only interruptible as a last resort under Requirement 2 of the NERC Standard EOP-011-1 between June 1st and September 30th.

v. A Market Participant may only qualify a PPA as a Capacity Resource if such agreement establishes a firm obligation on the part of the seller of the Capacity to deliver the Capacity to the Market Participant.

vi. If the terms and conditions in a PPA do not explicitly conform with every requirement of Section 69A.3.1.c. 4 (i) through (iv) above, the Transmission Provider will use alternative documentation and verification procedures to determine if the PPA qualifies as a Capacity Resource. A party seeking Capacity Resource status for a non-conforming PPA must provide the Transmission Provider with written information regarding whether: (a) the PPA was executed prior to October 20, 2008; (b) an RE has accredited the PPA to satisfy resource adequacy requirement provisions; (c) the PPA has provided reliable capacity to the Transmission Provider Region; (d) the supplier(s) of capacity in the PPA commit(s) to provide the capacity to an LSE in the Transmission Provider Region in a defined amount at a defined location based upon the supplier(s)' portfolio of generation assets; (e) energy from the PPA cannot be interrupted for economic reasons and will only be interrupted for force majeure type conditions as a last resort during Emergency conditions; (f) either the purchaser(s) or the supplier(s) of capacity in the PPA has committed to offer energy into the Day-Ahead Energy and Operating Reserves Market and all pre-Day-Ahead and the first post Day-Ahead Reliability Assessment Commitment processes for all periods for which energy is available under the PPA, consistent with the must offer provisions in Section 69A.5; (g) the physical resource(s) backing the PPA are identified by the

supplier of the PPA; (h) the portion of the physical resources backing the PPA has not otherwise been registered by any other entity as Capacity Resources in the Transmission Provider Region or as capacity resources in any other region; and (i) if the PPA is renewed, the PPA will be modified to comply with the terms of section 69A.3.1.c. 4 (i) through (iv) and (vi). The Transmission Provider will analyze all available alternative documentation and verification information. Based upon such analysis, the Transmission Provider will inform the party seeking Capacity Resource status for the PPA within 30 days whether the PPA qualifies as a Capacity Resource.

vii. No PPA may be qualified as a Capacity Resource if such agreement includes provisions permitting the seller to interrupt deliveries thereunder for reasons other than Force Majeure.

5. A Market Participant for an External Resource required to submit GVTC results must use Reasonable Efforts to submit GVTC by October 31 prior to the upcoming Planning Year. If circumstances prevent the Market Participant from submitting the GVTC results for the External Resource by October 31, the Market Participant must notify the Transmission Provider no later than five (5) Business Days after October 31 and request an extension. The extension request must include a reasonable explanation and justification for missing the deadline and an expected completion date prior to the upcoming Planning Year. The Transmission Provider will review each extension request on a case by case basis to determine whether or not to approve or deny the request to extend the GVTC deadline.

Denial of an extension will not preclude the Market Participant for the External Resource from utilizing the ICAP Deferral process as described in Section 69A.7.9.

6. Existing Resources that modify their registration, scheduling and market participation in the Energy and Operating Reserves Markets and become pseudo-tied External Resources after September 1, 2022 will be accredited at the lesser of class average SAC in Schedule 53 or the accreditation provisions governing External Resources in section 69A.4.1.b.

Use Limited Resources

The Market Participant shall identify eligible Generation Resources, Electric Storage Resources, Distributed Energy Aggregated Resources or External Resources to the Transmission Provider that are Use Limited Resources. The Market Participant that seeks to qualify a Generation Resource, Distributed Energy Aggregated Resource or External Resource as a Use Limited Resource under RAR shall meet all the requirements as specified in the BPM for Resource Adequacy. A Use Limited Resource must be able to operate for a minimum set of four (4) consecutive operating Hours across the Transmission Provider's coincident peak for each day in each applicable Season in order to qualify as a Capacity Resource, in accordance with the BPM for Resource Adequacy.

Intermittent Generation, Dispatchable Intermittent Resources, and Distributed Energy Aggregated Resources

Intermittent Generation, Dispatchable Intermittent Resources, and Distributed Energy Aggregated Resources are resources that are eligible to qualify as a Capacity Resource by a Market Participant provided that the Market Participant: (a) possesses ownership or equivalent contractual rights for the resource; (b) supplies historical performance data or required documentation for the resource as established in the BPM for Resource Adequacy; and (c) registers the resource with the Transmission Provider in accordance with the BPM for Market Registration (if the resource is located within the MISO Balancing Authority Area metered boundary), or the BPM for Resource Adequacy (if the resource is located outside the MISO Balancing Authority Area metered boundary).

Curtailments

At its sole discretion, the Transmission Provider may curtail exports not being used as capacity by an external balancing authority and/or recall External Resources, PPAs, and Diversity Contracts sourced from a Capacity Resource during a declared Energy Emergency. Procedures for such actions shall be specified in the operating procedures. With respect to external balancing authorities that have a Seams Operating Agreement with the Transmission Provider pursuant to Section 69 A.3.1.c.4, during a declared Energy Emergency in the MISO Balancing Authority Area, the Transmission Provider shall only interrupt or reduce Export Schedules associated with a sale of capacity on a reciprocal pro rata basis to that required of the external balancing authority in Section 69A.3.1.c.4.(iii).

A. Determination of Deliverability of Generation Resources, Electric Storage Resources, and External Resources:

The Transmission Provider shall be responsible for determining whether Generation Resources, Electric Storage Resources, and External Resources eligible to be Capacity Resources are deliverable to Load. The deliverable amount of such Generation Resources, Electric Storage Resources, and External Resources will be any combination of the following:

i. The amount of Network Resource Interconnection Service under Attachment X;

ii. The amount of Energy Resource Interconnection Service under Attachment X that is coupled with firm Transmission Service;

iii. The amount of firm Transmission Service associated with a Grandfathered Agreement that can only be used to satisfy PRMR within the LRZ of the Load under the Grandfathered Agreement;

iv. The amount of aggregate deliverability that a Generation Resource or External Resource was granted through the market transition deliverability test by the Transmission Provider and could qualify for Network Resource Interconnection Service; or

v. The amount of non-aggregate deliverability that a Generation Resource or External Resource was granted by the transmission provider and confirmed by a Network Customer as a designated Network Resource under the OASIS reservation process in place prior to either the initial effective date of the Energy Market in 2005 or that corresponding Transmission Owner's integration date, will be accepted by the Transmission Provider as deliverable to the Network Loads of

the Network Customer for that term of the confirmed designation, as such term may be extended.

B. Determination of Deliverability of Intermittent Generation, Dispatchable Intermittent Resources, and Electric Storage Resources:

The Transmission Provider shall be responsible for determining whether Intermittent Generation, Dispatchable Intermittent Resources, and Electric Storage Resources eligible to be Capacity Resources are deliverable to Load. The deliverable amount of such Intermittent Generation, Dispatchable Intermittent Resources, and Electric Storage Resources will be any combination of the following:

i. The amount of Network Resource Interconnection Service under Attachment X;

ii. The amount of Energy Resource Interconnection Service under Attachment X that is coupled with firm Transmission Service;

iii. The amount of firm Transmission Service associated with a Grandfathered Agreement that can only be used to satisfy PRMR within the LRZ of the Load under the Grandfathered Agreement;

iv. The amount of aggregate deliverability that the Intermittent Generation or Dispatchable Intermittent Resource was granted through the market transition deliverability test by the Transmission Provider and could qualify for Network Resource Interconnection Service; or,

v. The amount of non-aggregate deliverability that a Intermittent Generation or Dispatchable Intermittent Resource was granted by the transmission provider and confirmed by a Network Customer as a designated Network Resource under the

OASIS reservation process in place prior to either the initial effective date of the Energy Market in 2005 or that corresponding Transmission Owner's integration date, will be accepted by the Transmission Provider as deliverable to the Network Loads of the Network Customer for that term of the confirmed designation, as such term may be extended.

C. Determination of Deliverability of Distributed Energy Aggregated Resources

The Transmission Provider shall be responsible for determining whether Distributed Energy Aggregated Resources eligible to be Capacity Resources are deliverable to Load. The Distributed Energy Resource Aggregator will coordinate with the Electric Distribution Company in order for the Electric Distribution Company to perform a technical review of the Distributed Energy Aggregated Resource's transmission system impacts. Any MW found to be injecting onto the transmission system as a result of the technical review must demonstrate deliverability by obtaining External Network Resource Interconnection Service or firm Transmission Service in order to qualify for the Planning Resource Auction or a FRAP.

Retirement, Suspension, Installed Capacity (ICAP) Deferral and Replacement of Planning Resources

a. Retirement, Suspension, ICAP Deferral and Replacement

A Planning Resource for which a Market Participant requests a change in status in accordance with the System Support Resource (SSR) provisions described in Section 38.2.7 will no longer qualify as a Planning Resource effective as of the actual date that the status of the Planning Resource changes to Retire pursuant to Section 38.2.7. A Generation Resource that has the status of Suspend pursuant to Section 38.2.7 will continue to qualify as a Planning Resource in accordance with the BPM for Resource Adequacy. A Planning Resource for which a Market Participant submits an ICAP Deferral Notice will be subject to ICAP Deferral Requirements and Charges pursuant to Section 69A.7.9. As used in this section, "cleared ZRCs" include ZRCs that cleared in the PRA, were used in a FRAP, were used in an RBDC Opt Out, or were used to replace ZRCs in accordance with this section. As used in this section, "uncleared ZRCs" include ZRCs that did not clear in the PRA, were not used in a FRAP, were not used in an RBDC Opt Out or were not used to replace ZRCs in accordance with this section. If a Planning Resource for which a Market Participant converts Seasonal Accredited Capacity into ZRCs is Retired or Suspended prior to the end of the Season during the Planning Year in which the ZRCs cleared, such Market Participant must replace the cleared ZRCs with uncleared ZRCs. If a Market Participant does not replace such ZRCs associated with a Retired or Suspended Planning Resource, a Capacity Replacement Non-Compliance Charge will be assessed as determined below in this Section. If a Market Participant's Planning Resource fails to satisfy the ICAP deferral requirements set forth in Section 69A.7.9 and the Market Participant does not replace

cleared ZRCs with uncleared ZRCs, an ICAP Deferral Non-Compliance Charge will be assessed pursuant to Section 69A.7.9. If a Planning Resource for which a Market Participant converts Seasonal Accredited Capacity into ZRCs is unable to meet the applicable performance requirements for the cleared ZRCs as described in Section 69A.5 for greater than thirty-one (31) Days in total due to full or partial Generator Planned Outage during the Season of the Planning Year in which the ZRCs cleared, or for Planning Resources that are subject to Diversity Contracts for greater than one (1) Month during any Season of the Planning Year in which the ZRCs cleared, such Market Participant must replace the cleared ZRCs with uncleared ZRCs to transfer the performance requirements applicable to the Planning Resource. If a Market Participant does not replace such ZRCs associated with a Planning Resource, a Capacity Replacement Non-Compliance Charge will be assessed as determined below in this Section. A Planning Resource for which a Market Participant converts Seasonal Accredited Capacity into ZRCs that are used to replace cleared ZRCs must meet the applicable performance requirements as described in sections 69A.3.3.1 and 69A.5 for the balance of the Season of the Planning Year, subject to the same replacement requirements set forth above. Any combination of cleared or replaced ZRCs that are on full or partial Generator Planned Outage for greater than thirty-one (31) Days in total during a Season, or for any other reason including full or partial Generation Outages that were not planned but were known or could have been reasonably anticipated at the time of the PRA, as set forth in the Market Monitoring and Mitigation Business Practices Manual, or unavailable because subject to a Diversity Contract that is not available for greater than one (1) Month during a Season, will be assessed a Capacity Replacement Non-Compliance Charge. If a Planning Resource for which a Market Participant converts Seasonal Accredited

Capacity into ZRCs is unable to meet the applicable performance requirements for the cleared ZRCs as described in Sections 69A.3.3.1 and 69A.5 due to a Catastrophic Generator Outage any time during the Season(s) of the Planning Year in which the ZRCs cleared such Market Participant may replace the cleared ZRCs with uncleared ZRCs to transfer the performance requirements applicable to the Planning Resource. A Planning Resource may not transfer its performance requirements by replacing the cleared ZRCs with uncleared ZRCs other than in the case of suspension, retirement, ICAP deferral, Catastrophic Generator Outage or full or partial Generator Planned Outages that may exceed thirty-one (31) Days in the Season as discussed immediately above. Cleared ZRCs can be replaced with uncleared ZRCs that are not from the same LRZ or ERZ by examining post-replacement clearing as if it were the PRA clearing results, so that such replacement: (1) does not violate any CIL used in the PRA; (2) does not violate any CEL used in the PRA; (3) does not reduce the remaining total ZRCs for any LRZ of cleared ZRCs below the LCR for that LRZ; and (4) does not exceed any intra-regional flow ranges established under applicable seams agreements, coordination agreements, or transmission service agreements. ZRC replacements from LRZs or ERZs other than that of the cleared ZRCs will be processed in accordance with the following parameters:

i. ZRC replacement shall be processed on a first come, first served basis.
ii. The amount of cleared ZRCs in each LRZ or ERZs at the time of a ZRC replacement shall be based upon the current amounts of cleared ZRCs, including any previous replacement transactions.

ZRC replacement shall have no impact on settlements from the PRA, FRAPs, and RBDC Opt Out, including any assessed Capacity Replacement Non-Compliance Charges.

b. Capacity Replacement Non-Compliance Charge and Distribution

i. Capacity Replacement Non-Compliance Charges will be calculated as follows: the number of days for which the Market Participant had a replacement requirement but failed to replace per section 69A.3.1.h.a above multiplied by the amount of ZRCs that failed to be replaced multiplied by the sum of the ACP for the applicable Season and the daily CONE value (1/365 times CONE). The ACP and the CONE values will be based on the LRZ where the Planning Resource cleared those ZRCs. If the Planning Resource is represented in an ERZ connected to a single SRRZ, the applicable CONE value will be the greatest CONE value of all LRZs in the respective SRRZ. For External Resources represented in ERZs that are connected to multiple SRRZs or that are not connected to any SRRZs, the applicable CONE value will be the greatest CONE value of all LRZs in those connected SRRZs.

ii. Distribution of Capacity Replacement Non-Compliance Charges: Capacity Replacement Non-Compliance Charge revenues received by the Transmission Provider will be distributed to Market Participants representing LSEs that have met their Final PRMR during the applicable Season of the Planning Year on a *pro rata* basis, based upon their respective LSEs' share of Final PRMR for the Transmission Provider Region.

Energy Efficiency Resources (EE Resource)

An Energy Efficiency Resource is a Planning Resource, in which the Market Participant possesses ownership or equivalent contractual rights, from an end-use customer project (including the installation of more efficient devices or equipment or implementation of more efficient processes or systems) that was implemented after July 20, 2011, exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous reduction in electric energy consumption during On Peak daylight hours, as further described in the BPM for Resource Adequacy. EE Resources are eligible to qualify as Planning Resources by registering such EE Resources as Planning Resources with the Transmission Provider, as documented in the BPM for Resource Adequacy. An EE Resource can qualify as a Planning Resource for ZRCs for each Season for up to four (4) Planning Years immediately following the EE Resource's initial qualification provided that the energy efficiency measures are fully implemented prior to each Planning Year. ZRCs from EE Resources will be grossed-up by the amount of avoided transmission losses in accordance with Section 68A.8.b and also by the applicable PRM in accordance with Section 68A.2. EE Resources shall not require notice, dispatch, or operator intervention, such that the EE Resource will reduce the total amount of electrical energy needed, while delivering a comparable or improved level of end-use service, in accordance with the BPM for Resource Adequacy. The additional requirements for EE Resource measurement and verification are found in Attachment UU.

Demand Response Resources – Type I and Load Modifying Resources

Demand Response Resources – Type I and Load Modifying Resources can be offered as ZRCs in the PRA or can be used in FRAPs pursuant to Section 69A.9 or used in an RBDC Opt Out pursuant to Section 69A.9.1. As described below, a Demand Resource or behind the meter generation is eligible to qualify as a DRR – Type I or a Load Modifying Resource if it meets the following requirements. All DRR – Type I and LMRs that are cleared in the PRA or were submitted in a FRAP for a Season or submitted in an RBDC Opt Out must be available for use in the event of an Emergency as declared by the Transmission Provider, pursuant to the Emergency Operating Procedures of the Transmission Provider, unless replaced with other ZRCs pursuant to Section 69A.3.1.h. In accordance with the BPM for Resource Adequacy, the Transmission Provider will qualify a DRR – Type I or LMR for the applicable Season in the upcoming Planning Year. The Seasonal Accredited Capacity for DRR – Type Is and LMRs will be calculated pursuant to Schedule 53B.

Deployment Procedures for LMR

Procedures for deployment of LMR are found in the BPM for Resource Adequacy and emergency operating procedures. Such procedures shall be consistent with the information provided by the Market Participant regarding availability and notice time. At a minimum the Market Participant will provide the deployment parameters of the LMR (as described in Sections 69A.3.5 and 69A.3.6), during declared Emergencies prior to the use of Operating Reserves to achieve energy balance. The Market Participant shall, at all times, notify the Transmission Provider or Local Balancing Authority when the status or availability of an LMR changes, except for de minimis changes that do not need to be reported, according to procedures specified in the BPM for Resource Adequacy and emergency operating procedures. The Transmission Provider or Local Balancing Authority shall coordinate with the Market Participant that owns or controls such LMR when necessary to deploy or notify such LMR of a planned deployment. The Transmission Provider or Local Balancing Authority shall coordinate with the Market Participant that owns or controls such LMR when necessary to notify such LMR of a planned deployment through the issuance of Scheduling Instructions. Market Participants may be issued Scheduling Instructions during a declared Emergency or in anticipation of an Emergency at the discretion of Transmission Provider. Market Participants shall acknowledge Scheduling Instructions issued in accordance with BPM for Resource Adequacy for its LMRs. In the event of an anticipated Emergency where the Transmission Provider does not declare the actual Emergency at least two hours prior to the anticipated Emergency event, Market Participants are not obligated to meet the Scheduling Instructions issued in anticipation of such Emergency and

will not be penalized for non-performance. This does not apply to Scheduling Instructions issued after the declaration of an Emergency.

A Market Participant that acknowledges Scheduling Instructions for its LMR(s) as required by the BPM for Resource Adequacy will receive credit for one (1) of the minimum deployments or interruptions required for the LMR for the applicable Season whether or not an Emergency is declared. However, a Market Participant that fails to acknowledge the Scheduling Instructions as required by the BPM for Resource Adequacy will not receive credit for such deployment or interruption for its LMR(s).

An LMR that does not perform consistent with the Market Participant's response to its Scheduling Instructions in the event of an Emergency is subject to the penalty provisions of Section 69A.3.9 and will not receive credit as one (1) of the minimum deployments or interruptions required for such resource for the applicable Season.

Demand Resources (DR) with an Emergency Obligation

Demand Resources registered as either a DRR – Type I or LMR may be deployed to reduce Demand consistent with the submitted Capacity Availability submitted by the Market Participant representing the Demand Resource. A Market Participant shall test, validate, and measure its Demand Resources and submit the results to the Transmission Provider, which shall verify all Demand reduction claimed by a Market Participant, consistent with the procedures specified in the BPM for Demand Response. The accrediting, testing, validation, and Measurement and Verification developed by the Transmission Provider shall take into account any applicable State Regulatory Authority, Regional Entity, or other non-jurisdictional entities' requirements regarding duration, frequency and notification processes for the candidate Demand Resource. A Demand Resource that is sensitive to temperature changes or that is using a Statistical Measurement and Verification methodology must identify, at the time of registration, the extent of such parametric sensitivity to the Transmission Provider with sufficient detail to enable the Transmission Provider to verify whether the Demand Resource would be subject to penalties in Section 69A.3.9 for failure to achieve the targeted Demand reduction amount using the appropriate consumption baseline set forth in Attachment TT. Parametric sensitive analysis must include, but is not limited to, identifying the parameter changes and the parameter's elasticity of the LSE's Load, as further described in the BPM for Demand Response. In accordance with the BPM for Resource Adequacy, the Transmission Provider will qualify a DR for each Season in the upcoming Planning Year.

Demand Resource Eligibility

A Market Participant that possesses ownership or equivalent contractual rights in a Demand Resource can register a Demand Resource as a DRR – Type I or an LMR to participate in the Planning Resource Auction as documented in the BPM for Resource Adequacy. The Market Participant registering the Demand Resource must include the contracts with each end-use customer indicating rights to require the Demand Resource to curtail Load. Notwithstanding, a copy of a contract with an end-use customer will not be required if the Market Participant is the end-use customer. In addition, the Market Participant must meet the following requirements:

a. A Market Participant shall be prohibited from registering into the PRA any component of a Demand Resource that is concurrently registered, in whole or in part, under another DRR, LMR, or EDR whether by the same or a different Market Participant. A Demand Resource registering as an LMR shall not also register as either a DRR or EDR.

b. The Demand Resource must be equal to or greater than 100 kW (a grouping of smaller resources aggregated together as a Load Modifying Resource that is capable of reducing an LSE's Demand for the applicable Season may qualify in meeting this standard).

c. The Demand Resource must be available to be scheduled for a Demand reduction with a notification time requirement: (i) less than or equal to six (6) hours to register in the PRA as a DRR – Type I or an LMR – Type I; or, (ii) less than or equal to thirty (30) minutes to register as an LMR – Type II, in the applicable Seasons.

d. When a Demand Resource is issued Setpoint Instructions or Scheduling Instructions, performance will be evaluated as set forth in Attachment TT using the applicable Measurement and Verification.

e. Once the Setpoint Instruction, Scheduling Instruction, or Firm Service Level is achieved, the Demand Resource must be able to maintain the Setpoint Instruction, Scheduling Instruction, or Firm Service Level for at least four (4) continuous Hours.

f. Unless the Demand Resource is unavailable due to Force Majeure:

(i) A Demand Resource participating as a DRR – Type I or an LMR – Type I that is unavailable to respond to all Setpoint Instructions or Scheduling Instructions shall be subject to the penalties set forth in Section 69A.3.9; and

(ii) A Demand Resource participating as an LMR – Type II that is unavailable to respond to any Scheduling Instructions shall be subject to the penalties set forth in Section 69A.3.9.

This obligation only applies to Seasons during which a Demand Resource clears the Planning Resource Auction.

g. A Demand Resource for which curtailment is not an obligation during Emergency events declared by the Transmission Provider pursuant to the Transmission Provider emergency operating procedures, will not qualify to participate in the PRA as a DRR – Type I or qualify as an LMR.

A Market Participant that submits an Offer into the Day-Ahead and/or Real-Time

Energy and Operating Reserve Markets for a Demand Resource is still subject to the requirements to be available during an Emergency pursuant to the Transmission Provider Emergency Operating Procedures, regardless of the projected or actual Real-Time Energy market LMP.

h. A Demand Resource shall submit Metered data at regular intervals as set forth in Attachment TT.

i. A Market Participant must demonstrate demand reduction capability for each Planning Year on an annual basis as established in the BPM for Resource Adequacy. Beginning with the 2020/2021 Planning Year each Demand Resource must validate its performance by meeting the Transmission Provider's Scheduling Instructions when called upon during the prior Planning Year or conducting a real power test. A Demand Resource for which a real power test is conducted will receive credit as one (1) of the minimum deployments or interruptions required for such resource for the applicable Season of the Planning Year in which such a test occurs.

A Demand Resource may provide operational data, or develop an alternative mechanism, subject to the approval of the Transmission Provider, by which the demand reduction capability can be demonstrated without requiring an actual demand reduction if a real power test is precluded or waived due to one of the two conditions as specified below:

1) Such a real power test is precluded by any applicable regulatory restriction and such a limitation is documented during DR registration; or

2) A Market Participant may waive the obligation to conduct a real power test by notifying the Transmission Provider during DR registration and accepting a penalty equal to three (3) times the Hourly Real-Time Ex Post LMP at the Load CPNode described in and distributed pursuant to Section 69A.3.9. A Demand Resource providing such notice must satisfy credit requirements by March 1 prior to the Planning Year totaling the ICAP value registered, but not tested, multiplied by $2,400/MW, where $2,400 is the product of 3 * 4 * $200 to account for the three (3) times energy penalty assumed under the waiver, the four (4) hours of LMR requirements, and a $200 LMP as a proxy for pricing under emergency conditions.

All existing accredited Demand Resources that neither conduct a real power test nor meet Scheduling Instructions issued by the Transmission Provider during the prior Planning Year must participate in training provided by the Transmission Provider on the deployment of LMRs during the prior Planning Year. Any existing accredited Demand Resource must submit (1) the real power test results, (2) reference performance of Scheduling Instructions for demand reduction when called upon during the calendar year prior to the upcoming Planning Year, (3) alternate testing mechanism, relevant data, and a reference of training participation to the Transmission Provider, or (4) a Demand Resource Deferral Notice pursuant to 69A.3.5(l) and a reference of training participation to the Transmission Provider no later than February 1 prior to such Planning Year for

existing accredited DR. For new Demand Resources, (1) a real power test must be conducted and results submitted to the Transmission Provider, (2) alternate testing mechanism must be submitted, or (3) a Demand Resource Deferral Notice must be submitted prior to qualifying as a Demand Resource, but no later than March 1 prior to the PRA in accordance with the BPM for Resource Adequacy. During a transition period that shall apply only to the 2021-2022 Planning Year, Market Participants may submit a Demand Resource Deferral Notice no later than March 31, 2021 for existing accredited Demand Resource, and Market Participants may submit a Demand Resource Deferral Notice no later than March 31, 2021 prior to initially qualifying as a Demand Resource.

j. Market Participants providing physical, regulatory, or contractual limitations of the notice times and availability of Demand Resources must provide appropriate documentation to the Transmission Provider in accordance with the BPM for Resource Adequacy.

h. A Market Participant may defer the obligation to conduct a real power test, as set forth in section 69A.3.5(i), by providing a Demand Resource Deferral Notice to the Transmission Provider in writing and signed by an officer of the company no later than February 1st prior to the Planning Year. During a transition period that shall apply only to the 2021-2022 Planning Year, Market Participants may submit a Demand Resource Deferral Notice no later than March 31, 2021 for existing accredited Demand Resource, and Market Participants may submit a Demand Resource Deferral Notice no later than March 31, 2021 prior to initially

qualifying as a Demand Resource. The Demand Resource Deferral Notice shall contain: (1) the expected Demand Resource test value (in megawatts) from such Demand Resource and if the Demand Resource is new, the LBA or external BA where it is represented; and (2) appropriate information validating that real power test results will be submitted to the Transmission Provider by the last Business Day of May prior to the Planning Year. A Market Participant that provides a Demand Resource Deferral Notice must satisfy credit requirements by March 1 prior to the Planning Year totaling the amount of Demand Resource test value provided in the Demand Resource Deferral Notice multiplied by $2,400/MW, where $2,400 is the product of 3*4* $200 to account for the three (3) times energy penalty assumed under the deferral, the four (4) hours of LMR requirements, and a $200 LMP as a proxy for pricing under emergency conditions. During a transition period that shall apply only to the 2021-2022 Planning Year, Market Participants that have elected to submit a Demand Resource Deferral Notice must satisfy credit requirements by March 31, 2021. If the Market Participant submits the real power test results on or before the last Business Day of May prior to the Planning Year that are equal to or greater than the expected Demand Resource test value, then the Transmission Provider will adjust the Market Participant's credit requirement to account for these changes within twenty (20) Business Days after that real power test is submitted. In the event ZRCs associated with a Planning Resource for which Demand Resource testing has been successfully deferred are unconverted in accordance with section

69A.7.3, the Market Participant may provide notice to the Transmission Provider that it wishes to forfeit the deferred Demand Resource value, in which case the Transmission Provider will adjust the Market Participant's Demand Resource value and credit requirement within twenty (20) Business Days. A Market Participant that provides a Demand Resource Deferral Notice and that either (1) has not submitted any real power test result for such Demand Resource by the last Business Day of May prior to the Planning Year, or (2) has submitted a real power test result by the last Business Day of May prior to the Planning Year that demonstrates fewer megawatts are available than the expected Demand Resource test value submitted in the Demand Resource Deferral Notice, shall be subject to a penalty equal to three (3) times the Hourly Real-Time Ex Post LMP at the Load CPNode for any such deficiency described in and distributed pursuant to Section 69A.3.9. In addition, such Market Participant shall not have their credit released until a real power test result demonstrating the availability of all megawatts submitted in the Demand Resource Deferral Notice is submitted and verified by the Transmission Provider, or the end of the Planning Year, whichever is earlier.

Behind the Meter Generation Eligibility

1. A Market Participant that possesses ownership or equivalent contractual rights in a behind the meter generator can register such behind the meter generator as a DRR – Type I or an LMR to participate in the Planning Resource Auction as documented in the BPM for Resource Adequacy. A behind the meter generator registered as a DRR – Type I or an LMR is a BTMG. The Market Participant registering the BTMG must include the contracts with each end-use customer indicating rights behind the BTMG to generate behind-the-meter generation. Notwithstanding, a copy of a contract with an end-use customer will not be required if the Market Participant is, or has non-contractual legal rights to control, the end use customer. In addition, the Market Participant must meet the following requirements:
    a. A Market Participant shall be prohibited from registering into the PRA any BTMG that is concurrently registered, in whole or in part, under another DRR, LMR, or EDR, whether by the same or a different Market Participant. A BTMG registering as an LMR shall not also register as a DRR or EDR.
    b. The BTMG must be equal to or greater than 100 kW (a grouping of smaller resources aggregated together as a Load Modifying Resource that is capable of reducing an LSE's Demand for the applicable Season may qualify in meeting this standard).
    c. A behind the meter generator for which curtailment is not an obligation during Emergency events declared by the Transmission Provider will not qualify to participate in the PRA as a DRR – Type I or qualify as an LMR.

A Market Participant that submits an Offer in the Day-Ahead Market and/or Real-Time Energy and Operating Reserve Markets for a BTMG is still subject to the requirement to be available during an Emergency pursuant to the Transmission Provider Emergency Operating Procedures, regardless of the projected or actual Real-Time Energy Market LMP.

d. A Market Participant shall demonstrate GVTC capability for applicable Season in each Planning Year on an annual basis as established in the BPM for Resource Adequacy, and by submitting the GVTC results to the Transmission Provider no later than October 31 prior to such Planning Year for existing accredited BTMG unless the Transmission Provider has granted an extension pursuant to Section 69A.3.6.1.j. All new BTMGs or an existing accredited BTMG that has an increased installed capacity shall submit their GVTC to the Transmission Provider prior to qualification, but no later than March 1 prior to the PRA as established in the BPM for Resource Adequacy.

e. A Market Participant shall submit generator availability data (including, but not limited to, NERC GADS information) into a database provided by the Transmission Provider and as established in the BPM for Resource Adequacy. A Market Participant is not required to report generator availability data based on GVTC for a BTMG less than 10 MW if the Market Participant has never provided such data for such BTMG. A Market Participant that begins reporting generator availability data based upon GVTC for a BTMG that is less than 10 MW must continue to report such data.

f. A BTMG must be available to provide Energy with a notification time requirement: (i) of six (6) hours or less notice if registering in the PRA as a DRR – Type I or an LMR – Type I; or (ii) with thirty (30) minutes or less notice if registering as an LMR – Type II in the applicable Seasons.

g. A Market Participant shall demonstrate that the BTMG is able to sustain energy production at the MW level being registered for at least four (4) continuous Hours;

h. Unless unavailable due to Force Majeure:

(i) A BTMG participating as a DRR – Type I or LMR – Type I that is unavailable to respond to all Setpoint Instructions or Scheduling Instructions shall be subject to the penalties set forth in Section 69A.3.9; and

(ii) A BTMG participating as an LMR – Type II that is unavailable to respond to any Scheduling Instruction shall be subject to the penalties set forth in Section 69A.3.9.

This obligation only applies during Seasons which the BTMG clears the Planning Resource Auction.

i. A BTMG shall submit Metered data at regular intervals as set forth in Attachment TT.

j. A Market Participant registering a BTMG may not register as a DRR – Type II or Non-Emergency BTMG for three years (3) Planning Years. After three (3) Planning Years, a Market Participant may commit to participate as a BTMG for

an additional three (3) Planning Years or may elect to participate as a DRR – Type II or Non-Emergency BTMG. A BTMG may opt to participate as a DRR – Type I or LMR at any time by satisfying the requirement of such participation option.

k. A Market Participant for a BTMG required to submit GVTC results must use Reasonable Efforts to submit GVTC by October 31 prior to the upcoming Planning Year. If circumstances prevent the Market Participant from submitting the GVTC results for the BTMG by October 31, the Market Participant must notify the Transmission Provider no later than five (5) Business Days after October 31 and request an extension. The extension request must include a reasonable explanation and justification for missing the deadline and an expected completion date prior to the upcoming Planning Year. The Transmission Provider will review each extension request on a case by case basis to determine whether or not to approve or deny the request to extent the GVTC deadline. Denial of an extension will not preclude the Market Participant for the BTMG from utilizing the ICAP Deferral process as described in Section 69A.7.9.

2. Installed Capacity (ICAP) Deferral

If a Market Participant for a BTMG has not completed GVTC testing by the deadlines provided in 69A.3.6.1.d, is not expected to demonstrate deliverability, or is otherwise not expected to demonstrate commercial operation prior to March 1, ZRCs from such capacity may be used the PRA, in a FRAP (including through bilateral ZRC transactions) or in an RBDC Opt Out, subject to the notification, credit, and non-compliance

provisions of Section 69A.7.9.

Transmission Provider Initiated Testing of Demand Resources

1. A Demand Resource participating as a DRR or a LMR that is registered in the PRA shall be subject to a Transmission Provider initiated test according to the following requirements:

   a. Test frequency:

      i. A Demand Resource using an Attachment TT defined Statistical Measurement and Verification methodology shall be tested once per Planning Year;

      ii. A Demand Resource participating as a DRR or LMR – Type I shall be tested once per three (3) Planning Years;

      iii. A Demand Resource participating as an LMR – Type II shall be tested once per Planning Year. A Market Participant representing a Demand Resource participating as an LMR – Type II may request a Transmission Provider initiated test opt out as set forth in Section 69A.3.8.2; or

      iv. Notwithstanding the provisions above, the Transmission Provider may test a resource at any time due to its non-performance.

   b. A Demand Resource that has successfully deployed in response to a Setpoint Instruction or Scheduling Instruction issued during an Emergency in either the past one (1) or three (3) Planning Years as applicable pursuant to sub-section a. above, shall count as a successful Transmission Provider initiated test. Provided there are no deployment failures for a Demand Resource participating as an LMR during the 2025/2026, 2026/2027, and 2027/2028 Planning Years, full

response to Setpoint Instructions or Scheduling Instructions issued during an Emergency shall count as a successful Transmission Provider initiated test for the first one (1) or three (3) Planning Year cycle, as applicable, beginning with the 2028/2029 Planning Year.

c. A new Demand Resource participating as a DRR or an LMR shall undergo a Transmission Provider initiated test during the first Planning Year it is registered for the PRA.

d. A Market Participant shall receive at least 24 hours notification prior to the initiation of a Transmission Provider initiated test. Additional requirements regarding the Transmission Provider initiated test shall be set forth in the BPM for Resource Adequacy.

2. A Demand Resource participating as an LMR – Type II may opt out of the annual Transmission Provider initiated test requirement if it has responded to all Scheduling Instructions and successfully passed all Transmission Provider initiated tests, within the past three (3) Planning Years.

a. If opting out of a test, a Demand Resource opting out of the test shall be subject to increased real-time penalties equal to the product of Pricing VOLL and the amount of specified Demand reduction, measured in MWh, not achieved in response to a Setpoint Instruction or Scheduling Instruction issued during an Emergency, in addition to any other penalty provisions set forth in 69A.3.9.

3. A Demand Resource will be deemed to have fully satisfied the Transmission Provider initiated test if the resource has met its performance obligations, as set forth in

Attachment TT, within the registered notification time, and maintained the Demand reduction or Firm Service Level as applicable for four (4) continuous hours.

4. A Demand Resource will have partially failed the Transmission Provider initiated test if the Demand Resource fully deploys outside of the registered notification time and within six (6) hours of initiating the test for participating as DRR – Type I or LMR – Type I, within thirty (30) minutes of initiating the test for participating as LMR – Type II, and within the Offered Shut-Down time for participating as a DRR – Type II. A partial failure of a Transmission Provider initiated test will result in:

   a. The Demand Resource being charged the product of the amount of the Demand shortfall, measured in MW at the Hour equal to the initiation of the Transmission Provider test plus the registered response time, and the Auction Clearing Price, for the lesser of:

      i. The remainder of the Season; or

      ii. Such time as the Demand Resource fully deploys in response to a Setpoint Instruction or Scheduling Instruction during a Transmission Provider declared Emergency.

   b. The Transmission Provider will adjust the resource's registered response time to reflect its tested response. A Market Participant must provide evidence to the Transmission Provider to register such resource with a response time less than the response time achieved during the Transmission Provider initiated test during subsequent Planning Years.

   c. The Demand Resource may be tested in subsequent Seasons during the same

Planning Year.

d. The Demand Resource shall be tested in the subsequent Planning Year.

5. A Transmission Provider initiated test shall be deemed to be fully failed if the Demand Resource failed to achieve its required Demand reduction, as measured per the applicable Attachment TT Measurement and Verification identified during the registration of the resource, within six (6) hours of initiating the test for participating as DRR – Type I or LMR – Type I, within thirty (30) minutes of initiating the test for participating as LMR – Type II, and within the Offered Shut-Down time for participating as a DRR – Type II.

a. A Demand Resource experiencing a complete test failure will be subject to penalties equal to the product of the cleared ZRCs and the ACP for the entire Season in which the test was performed.

b. The Transmission Provider shall perform a test in the subsequent Season the resource has cleared ZRCs.

c. A resource failing two (2) tests during a single Planning Year shall be fully disqualified for the remainder of the Planning Year and shall pay 2.748 times the applicable LRZ's CONE multiplied by the amount of cleared ZRCs for each Season.

Penalty Provisions for LMRs

Unless an LMR is unavailable as a result of maintenance requirements, for reasons of Force Majeure, or because the number of required deployments based on the registered number has been reached, the Market Participant representing the entity that had ZRCs from LMRs that cleared in the PRA, were used in a FRAP, or were used in an RBDC Opt Out will be subject to the following penalties in the event the LMR is called upon during an Emergency as declared by the Transmission Provider and the LMR fails to perform in accordance with its Market Participant's response to such Market Participant's Scheduling Instructions. The penalties defined below will only apply to the portion of the Market Participant's response to such Market Participant's Scheduling Instruction that is not followed during the Emergency declaration and will only be assessed by the Transmission Provider after giving the operator of the LMR an opportunity to provide documentation of the specific circumstances that would justify exemption from such penalties. There will not be an LMR penalty assessed for any portion of the Scheduling Instruction which had already been accomplished by an LMR for other reasons (*e.g.*, for economic considerations, self-scheduling at or above the credited amount of BTMG or local reliability concerns in accordance with instructions from the Local Balancing Authority) at the time the request for interruption is made by the Transmission Provider. Likewise, for certain Demand Resources that are temperature dependent (*e.g.*, a Demand Resource program involving air conditioning load), the specified Demand reduction may be adjusted in a manner defined in the measurement and verification procedures developed by the Transmission Provider to reflect the circumstances at the time a Demand Resource is called upon to reduce Demand.

a. The Transmission Provider shall assess the responsible Market Participant the costs that were otherwise incurred to replace the deficient Planning Resource at the time the Market Participant's LMR is called upon by the Transmission Provider and does not respond in full or in part consistent with the Market Participant's response to MISO's Scheduling Instructions. These costs will be the product of the amount of specified Demand reduction not achieved and the Hourly Real-Time Ex Post LMP at the Load CPNode, plus any applicable Revenue Sufficiency Guarantee charges. The Transmission Provider shall allocate any such penalty revenues only to the Market Participants representing the LSEs in the Local Balancing Authority Area(s) that experienced the Emergency that required the use of an LMR. Such revenues shall be distributed on a Load Ratio Share basis. For any situation where either an LMR does not respond to an interruption request, including those circumstances where the LMR is claimed to be unavailable as a result of maintenance requirements or for reasons of Force Majeure, the Transmission Provider shall initiate an investigation with the Market Participant which has registered the Demand Resource or BTMG and was qualified as an LMR into the cause of the LMR not being available when called upon to reduce Demand. If deemed appropriate by the Transmission Provider, the Transmission Provider will disqualify the Demand Resource or BTMG from further use as an LMR for the remainder of the current Planning Year, and will discontinue payment of the applicable ACP for the remainder of the current Planning Year when the LMR was unavailable. If such

LMR was used in a FRAP or cleared in the PRA or used in an RBDC Opt Out, then the Market Participant will be charged the applicable ACP for the remainder of the current Planning Year for the Unforced Capacity of the LMR. The revenues collected will be distributed on a *pro rata* basis in such LRZ based upon an LSE's Final PRMR.

b. In the event the same LMR is unavailable on a second occasion (with at least a separation period of 24 hours) when called upon to respond to Scheduling Instructions, except for a validated circumstance of maintenance requirements or for reasons of Force Majeure, the Market Participant taking credit for that LMR shall make the same penalty payment as indicated in Section 69A.3.9.a above, and the Demand Resource or BTMG will no longer qualify as an LMR and will not receive the applicable ACP for the remainder of the current Planning Year and will not be eligible for LMR status for the next Planning Year. If such LMR was used in a FRAP or cleared in the PRA or used in an RBDC Opt Out, then the Market Participant will be charged the applicable ACP for the remainder of the current planning year for the Unforced Capacity of the LMR. The revenues collected will be distributed on a *pro rata* basis in such LRZ based upon an LSE's Final PRMR.

Non-Emergency Behind the Meter Generation Eligibility

1. A Market Participant that possesses ownership or equivalent contractual rights in a behind the meter generator can register such behind the meter generator as a Non-Emergency BTMG to participate in the Planning Resource Auction as documented in the BPM for Resource Adequacy. The Market Participant registering the Non-Emergency BTMG must include the contracts with each behind the meter generator indicating rights behind the Non-Emergency BTMG to generate behind-the-meter generation. Notwithstanding, a copy of a contract with a behind the meter generator will not be required if the Market Participant is, or has non-contractual legal rights to control, the behind the meter generator. In addition, the Market Participant must meet the following requirements:

    a. A Market Participant shall be prohibited from registering into the PRA any Non-Emergency BTMG that is concurrently registered, in whole or in part, whether by the same or a different Market Participant.

    b. The Non-Emergency BTMG must be equal to or greater than 100 kW (a grouping of smaller resources aggregated together as a single Non-Emergency Behind the Meter Generation resource may qualify in meeting this standard).

    c. At registration, a Market Participant registering a Non-Emergency BTMG must commit to participate as a Non-Emergency BTMG for three (3) Planning Years. After three (3) Planning Years, a Market Participant may commit to participate as a Non-Emergency BTMG for an additional three (3) Planning Years or may elect to participate as a DRR – Type I or an LMR. A resource participating as a Non-

Emergency BTMG may opt to participate as a DRR – Type II Resource at any time by satisfying the requirements of a DRR – Type II.

d. A Non-Emergency BTMG has no obligation to respond to a Transmission Provider Setpoint Instruction or Scheduling Instruction.

e. A Market Participant registering a Non-Emergency BTMG shall demonstrate GVTC capability for the applicable Season in each Planning Year on an annual basis as established in the Business Practices Manual for Resource Adequacy. A Market Participant of an existing Non-Emergency BTMG must submit the GVTC results to the Transmission Provider no later than October 31 prior to such Planning Year. If circumstances prevent the Market Participant from submitting the GVTC results for the Non-Emergency BTMG by October 31, the Market Participant must notify the Transmission Provider no later than five (5) Business Days after October 31 and request an extension. The extension request must include a reasonable explanation and justification for missing the deadline and an expected completion date prior to the upcoming Planning Year. The Transmission Provider will review each extension request on a case by case basis to determine whether or not to approve or deny the request to extend the GVTC deadline. Denial of an extension will not preclude the Market Participant for the Non-Emergency BTMG from utilizing the ICAP Deferral process as described in Section 69A.7.9.

A Market Participant of all new Non-Emergency BTMGs, or an existing accredited Non-Emergency BTMG that have increased installed capacity, shall

submit their GVTC to the Transmission Provider prior to qualification, but no later than March 1 prior to the PRA.

A Market Participant may request an extension of these deadlines pursuant to Section 69A.3.10.2.

f. A Market Participant shall submit generator availability data (including, but not limited to, NERC GADS information) into a database provided by the Transmission Provider and as established in the Business Practices Manual for Resource Adequacy. A Market Participant is not required to report generator availability data based on GVTC for a Non-Emergency BTMG less than 10 MW if the Market Participant has never provided such data for such Non-Emergency BTMG. A Market Participant that begins reporting generator availability data based upon GVTC for a Non-Emergency BTMG that is less than 10 MW must continue to report such data.

g. A Market Participant for Non-Emergency BMTG shall submit Meter data at regular intervals as set forth in Attachment TT.

2. Installed Capacity (ICAP) Deferral

If a Market Participant for a Non-Emergency BTMG has not completed GVTC testing by the deadlines provided in 69A.3.10(e), is not expected to demonstrate deliverability, or is otherwise not expected to demonstrate commercial operation prior to March 1, ZRCs from such capacity may be used the PRA, in a FRAP (including through bilateral ZRC transactions), or in an RBDC Opt Out, subject to the notification, credit, and non-compliance provisions of Section 69A.7.9.

Planning Resource Capacity Values

In order for the Transmission Provider to account for resource performance and availability, Capacity Resources, Demand Response Resources – Type I, Load Modifying Resources, and Non-Emergency Behind the Meter Generation will be given a capacity value for each applicable Season based on the Seasonal Accredited Capacity calculation applicable to its Resource type; and EE Resources will be given capacity values based on the measurement and verification data provided for such resources, as provided in the BPM for Resource Adequacy.

Seasonal Accredited Capacity of Capacity Resources

The Transmission Provider will determine the Seasonal Accredited Capacity for each Capacity Resource.

a. The Seasonal Accredited Capacity for a Capacity Resource that is a Generation Resource, but not a Dispatchable Intermittent Resource, Intermittent Generation, Electric Storage Resource, External Resource, or Use Limited Resource, is based on an evaluation of the type and volume of interconnection service, GVTC value, and Real-Time offered availability of such Generation Resource or Electric Storage Resource for each Season as set forth in Schedule 53.

b. The Seasonal Accredited Capacity for a Capacity Resource that is an External Resource, but not a Dispatchable Intermittent Resource, Intermittent Generation or Use Limited Resource, is based on the GVTC value and $XEFOR_d$ values of such External Resource for each Season. External Resources that are not required to report generator availability data will have a forced outage rate based on the class average forced outage rate of the resource type.

c. The Transmission Provider will determine the Seasonal Accredited Capacity for a DRR – Type II that qualifies as a Capacity Resource, for each Season, as set forth in Schedule 53B.

d. The Seasonal Accredited Capacity for a Capacity Resource that is a Dispatchable Intermittent Resource or Intermittent Generation will be determined by the Transmission Provider based on historical performance, availability, and type and volume of interconnection service, for each Season in accordance with the BPM

for Resource Adequacy.

e. The Seasonal Accredited Capacity value for a Capacity Resource that is a Hybrid Resource will be established by the Transmission Provider based on the sum of the Seasonal Accredited Capacity values of its respective Electric Facilities for the production and/or storage for later injection of electricity, up to the level of firm interconnection service, prior to a minimum amount of operating data becoming available. Once sufficient operation data is available, as defined in the BPM, the Seasonal Accredited Capacity value for a Hybrid Resource will be determined by the Transmission Provider based on historical performance, availability, and type and volume of interconnection service, for each Season in accordance with the BPM.

f. The Seasonal Accredited Capacity of a Capacity Resource that is an Electric Storage Resource will be established by the Transmission Provider based on an evaluation of the type and volume of interconnection service, a GVTC value based upon a power and energy test, and an $XEFOR_d$. Electric Storage Resources that are not required to report generator availability data will have an $XEFOR_d$ rate based on their class average forced outage rate.

g. The Seasonal Accredited Capacity for a Capacity Resource that is a Use Limited Resource will be determined by the Transmission Provider based on the type and volume of interconnection service, the GVTC and $XEFOR_d$ values of such Use Limited Resource in accordance with the BPM for Resource Adequacy.

Seasonal Accredited Capacity of Demand Resources

The Transmission Provider will determine the appropriate Seasonal Accredited Capacity value for Demand Resources that qualify as a Planning Resource as established in Schedule 53B.

Seasonal Accredited Capacity of Behind the Meter Generation and Non-Emergency Behind the Meter Generation

The Transmission Provider will determine the Seasonal Accredited Capacity for each BTMG and Non-Emergency BTMG as set forth in Schedule 53B. If such BTMG or Non-Emergency BTMG is interconnected to the Transmission System, the Transmission Provider will consider the type and volume of interconnection service when determining the Seasonal Accredited Capacity.

EE Resources

The Seasonal Accredited Capacity for a qualified EE Resource will be determined by the Transmission Provider based upon submitted measurement and verification documents, as provided in the BPM for Resource Adequacy.

Attributes of ZRCs

A Market Participant that owns or possesses equivalent contractual rights to a qualified Planning Resource can convert the convertible Seasonal Accredited Capacity of the Resource (Seasonal Accredited Capacity MW) as determined in section 69.A.3.1.g into ZRCs through the MECT in order to offer such ZRCs into a PRA. Market Participants also can unconvert and/or transfer ZRCs through the MECT to another Market Participant, as described in the BPM for Resource Adequacy.

A. Eligibility for Zonal Resource Credits for a Capacity Resource that is a Planning Resource that is not Intermittent Generation or Dispatchable Intermittent Resource.

For a Capacity Resource that is not Intermittent Generation or Dispatchable Intermittent Resource the amount of Capacity that is eligible to be converted to Zonal Resource Credits shall be the convertible Seasonal Accredited Capacity value of the Capacity Resource. The convertible Seasonal Accredited Capacity shall be determined by:

i. Determining the Installed Capacity;

ii. Determining the Seasonal Accredited Capacity of the Capacity Resource;

iii. Allocating the Capacity Resource's Seasonal Accredited Capacity value where:

a. If the Capacity Resource has only Energy Resource Interconnection Service, the Seasonal Accredited Capacity will be allocated to the Capacity Resource's Energy Resource Interconnection Service Seasonal Accredited Capacity value, which will be calculated by multiplying the lesser of the Capacity Resource's ICAP or Energy Resource Interconnection Service by SAC divided by ICAP;

b. If the Capacity Resource has both Network Resource Interconnection Service and Energy Resource Interconnection Service, the Seasonal Accredited Capacity will be allocated first to the Capacity Resource's Network Resource Interconnection Service Seasonal Accredited Capacity value, which will be calculated by multiplying the lesser of the Capacity Resource's ICAP or Network Resource Interconnection Service by SAC divided by ICAP, as provided below:

NRIS SAC = MIN (NRIS, ICAP) × (SAC/ICAP)

c. Any remaining total Seasonal Accredited Capacity value will then be allocated to Energy Resource Interconnection Service Seasonal Accredited Capacity as provided below:

ERIS SAC = MAX (0, (ICAP-NRIS)) × (SAC/ICAP)

d. The resulting Network Resource Interconnection Service Seasonal Accredited Capacity value shall be eligible to be converted into Zonal Resource Credits; and

e. The resulting Energy Resource Interconnection Service Seasonal Accredited Capacity value that is coupled with firm Transmission Service shall be eligible to be converted into Zonal Resource Credits up to the Energy Resource Interconnection Service Unforced Capacity value of the Capacity Resource, by multiplying the firm Transmission Service amount by SAC divided by ICAP.

B. Eligibility for Zonal Resource Credits for a Capacity Resource that is an Intermittent Generation or Dispatchable Intermittent Resource

For Intermittent Generation and Dispatchable Intermittent Resources that are Capacity Resources, the amount of Capacity eligible to be converted to Zonal Resource Credits shall be the convertible Seasonal Accredited Capacity value of the Intermittent Generation or Dispatchable Intermittent Resource, which is equal to the total Seasonal Accredited Capacity value multiplied by the quotient of the deliverability adjusted Capacity factor divided by the peak performance Capacity factor of the Capacity Resource where:

a. the deliverability-adjusted capacity factor is the average of the actual Energy output capped at the demonstrated deliverability of the Intermittent Generation or Dispatchable Intermittent Resource determined in Section 69A.3.1.g during the highest system peak load observances for each Season that the Capacity Resource was in service divided by the Installed Capacity of the Capacity Resource; and,

b. the existing peak performance Capacity factor is the average of the actual Energy output during the highest system peak load observances for each Season that the Capacity Resource was in service divided by the Installed Capacity of the Capacity Resource.

C. Eligibility for Zonal Resource Credits for a Capacity Resource that is a Distributed Energy Aggregated Resource

For Distributed Energy Aggregated Resources that are Capacity Resources, the amount of Capacity eligible to be converted to Zonal Resource Credits shall be the convertible Seasonal

Accredited Capacity value of the Distributed Energy Resources within the aggregation according to their resource type as determined in section 69A.3.1.g.

Capacity Resource Must Offer and Performance Requirements

a. Market Participants that convert Seasonal Accredited Capacity from Capacity Resources into ZRCs that clear in a Season in the PRA or are used in a FRAP (and that do not replace such ZRCs in accordance with Section 69A.3.1.h) or used in an RBDC Opt Out, including Capacity Resources that are the subject of Diversity Contracts, must submit Self-Schedules or Offers for Energy, and Contingency Reserve if qualified, and offers for Short-Term Reserve if qualified, for the Installed Capacity value of the Capacity Resources converted to ZRCs and clear in a Season in the PRA or used in a FRAP or used in an RBDC Opt Out for each Hour of each Day during the applicable Season in the Planning Year, in the Day-Ahead Energy Market and all pre Day-Ahead and the first post Day-Ahead Reliability Assessment Commitment process. This must offer obligation does not apply to the extent that the Capacity Resource is unavailable due to a full or partial forced or scheduled outage, in accordance with the BPM for Resource Adequacy and the BPM for Outage Operations. Additionally, this must offer obligation is modified to the extent the Capacity Resource is provided an operating limitation, such as thermal, voltage, or stability limits referenced in the BPM for Outage Operations, by the Transmission Provider or Transmission Operator to preserve the reliability of the Transmission System, that is lower than the must offer obligation described above, for the duration of such limitation.

Any such Capacity Resource with full or partial Generator Planned Outages that exceeds thirty-one (31) Days during any Season will be deemed not to have met its performance requirement for any Days greater than thirty-one (31) Days and must replace ZRCs in

accordance with Section 69A.3.1.h, provided that Capacity Resources subject to Diversity Contracts that are unavailable for greater than thirty-one (31) Days in total during any Season, will be deemed not to have met its performance requirement and will be subject to the ZRC replacement provisions set forth in Section 69A.3.1.h. Self-Schedules or Offers for Energy must be made consistent with requirements specified in Sections 39 and 40 of this Tariff as well as in the BPM for Resource Adequacy and the Business Practices Manual for Energy and Operating Reserves Markets. Partial or full forced or scheduled outages or derates of Capacity Resources must be reported in the Transmission Provider's Outage Scheduler, as described in further detail in the Business Practices Manual for Outage Operations. Must offer requirements specified in the BPM for Resource Adequacy will reflect resource operational limitations, including those related to Use Limited Resources, fuel limited, energy output limited or Intermittent Generation and including all state regulations and laws, including but not limited to, state safety standards, planning reserve margins, or the enforcement thereof. The Transmission Provider will monitor compliance with must offer requirements in accordance with the BPM for Resource Adequacy.

b. If a Capacity Resource that has ZRCs cleared in the PRA during any Season or is used in a FRAP during any Season or used in an RBDC Opt Out is capable of performing but fails to perform when called upon by the Transmission Provider for an Emergency, the Transmission Provider shall assess the owner of such Capacity Resource the costs that were otherwise incurred to replace the energy from the deficient Capacity Resource at the time that the Capacity Resource is called upon by the Transmission Provider and does not

respond in full or in part, for each day of non-performance of such Capacity Resource, provided that the planned or forced outage of the Capacity Resource is not properly reported in the Transmission Provider's Outage Scheduler, as set forth in the Business Practices Manual for Outage Operations. These costs will be the product of the amount of qualified ZRCs not achieved and the real-time LMP at the Capacity Resource's CPNode, plus any applicable related Revenue Sufficiency Guarantee charges. The Transmission Provider shall allocate any such revenues to the Market Participants representing the LSEs in the Local Balancing Authority Area(s) that experienced the Emergency. Such revenues shall be distributed on a Load Ratio Share basis.

c. Market Participants must input all Energy Efficiency Resource and Load Modifying Resource information into the MECT at least seven (7) Business Days prior to the Planning Resource Auction.

State RAR Standards

The Transmission Provider will assist states in meeting any state resource adequacy standards by providing relevant MECT information as available and as may be requested by states, subject to the data confidentiality provisions in Section 38.9 of this Tariff. Nothing in the RAR shall prohibit any state from requesting data relating to state safety standards, planning reserve margins, or the enforcement thereof.

Information regarding RAR Obligations

The Transmission Provider will maintain databases and will report to states and the affected LSEs, upon request, aggregated, non-confidential information regarding jurisdictional LSEs' RAR obligations during relevant time periods. Confidential Data regarding RAR status will be provided to states only in accordance with the data confidentiality provisions in Section 38.9 of this Tariff.

Facilitation of a Bilateral Capacity Bulletin Board

The Transmission Provider shall maintain an electronic bulletin board platform that may be used by Market Participants to facilitate voluntary bilateral ZRC transactions and to monitor the conversion of Seasonal Accredited Capacity to ZRCs.

Facilitation of LSE’s RAR Information

The Transmission Provider shall, upon request, submit RAR information to the applicable RE, Electric Reliability Organization, state (in the case of an LSE subject to regulation or using delivery services rates, terms or conditions established by such State Regulatory Authority) or to the Commission, subject to the provisions of Section 38.9 of this Tariff.

Reliability Based Demand Curve Procedures

A. Translation of MRI Curves to RBDCs

The following process will be utilized to determine the RBDC for the Transmission Provider Region for each Season of the upcoming Planning Year. The MRI Curves for the Transmission Provider Region as described in Section 68A.9 will be multiplied by a scaling factor measured in $/MWh. The scaling factor for an RBDC is calculated to support ACPs that achieve annual Net CONE when the Transmission Provider Region is at the reliability requirement established by the LOLE analysis for each Season. LOLE risk across the Seasons is modeled as described in Section 68A.2.1. The scaling factors shall be determined as set forth in the Business Practices Manual for Resource Adequacy.

The process used to determine the RBDCs for each of the First Planning Area and the Second Planning Area for each Season in the Planning Year is similar to the process used for developing the RBDC curve for the Transmission Provider Region.

B. Monte Carlo Analysis

Every three Planning Years, the Transmission Provider will evaluate the ability of RBDCs, through probabilistic analysis, to reliably serve the Transmission Provider Region's Demand while supporting ACPs that achieve annual Net CONE when the Transmission Provider Region is at the reliability requirement established by the LOLE analysis for each Season. The probabilistic analysis shall use a Monte Carlo study that assumes there are no internal transmission limitations within the Transmission Provider Region.

The Monte Carlo analysis will model both in-market supply and demand based on historic supply and demand variability, respectively, observed through a minimum of the three

most recent PRAs. The Monte Carlo model will produce seasonal clearing prices and quantities with each draw. Overall model results will be assessed by comparing the average of seasonal prices from the study against the estimate of Net CONE described in section 69A.8. The scaling factor is adjusted in each successive Monte Carlo simulation so that long run equilibrium conditions are ultimately achieved, indicated by the average of seasonal prices from the study equal to the estimate of Net CONE. Net CONE values used for the Monte Carlo analysis will be the simple arithmetic average of all LRZ Net CONE values.

A separate Monte Carlo analysis will be performed to evaluate the RBDCs for the First Planning Area and the Second Planning Area. Separate scaling factors will be used in the Monte Carlo analysis for each of the First Planning Area and the Second Planning Area that supports achievement of Net CONE values for the corresponding Planning Area, indicated by the average of seasonal capacity prices under long run equilibrium conditions. Net CONE values used in the Monte Carlo analysis for the RBDCs for the First Planning Area and the Second Planning Area will be the simple arithmetic average of LRZ Net CONE values for the specific LRZs in the corresponding Planning Area.

Planning Resource Auction

Within twenty (20) Business Days after the last Business Day in March, the Transmission Provider will conduct a PRA to determine the ACP in each LRZ and ERZ for the upcoming Planning Year which begins on June 1st. The Transmission Provider will post the results of the PRA on its website, consistent with the standards and procedures set forth in the BPM for Resource Adequacy. The Transmission Provider shall ensure that each Market Participant submitting a ZRC Offer is qualified to submit such an offer consistent with the Transmission Provider's creditworthiness provisions. The Transmission Provider will ensure that the LCR, the CEL and CIL are respected for each LRZ, the CEL is respected for each ERZ, and the SREC and the SRIC are respected for each SRRZ, if applicable, when conducting the PRA.

PRA Procedures

a. **Participating ZRCs in the PRA:** All Market Participants that own or have contractual rights to the Planning Resources that are represented within an LRZ or ERZ and have converted Seasonal Accredited Capacity to ZRCs, will have an option to (consistent with withholding provisions) submit offers into the PRA for such ZRCs, to the extent that the Market Participant has not submitted a FRAP, or RBDC Opt Out, as described in Section 69A.9. Owners of jointly-owned facilities can individually offer their share of any such resources into the PRA, either as self-schedule price takers or with specific offers, or use their share of such resources as part of their FRAPs, or RBDC Opt Outs. These ZRC Offers must be submitted in price/quantity pairs on a monotonically increasing basis expressed as MW-day and must consist of a stepped ZRC Offer curve of up to five (5) segments for each Planning Resource. ZRC Offers shall be submitted to the Transmission Provider via the MECT during the PRA offer window. Only ZRCs that are not otherwise committed for the remainder of the Planning Year are permitted to participate in the PRA. The PRA offer window shall begin at 8:00 am EPT three (3) Business Days before the last Business Day in March and shall end at 6:00 pm EPT on the last Business Day in March. The Transmission Provider may extend or reopen the PRA offer window based on unanticipated events that: (i) interfere with the Transmission Provider's ability to receive and/or process accurate and complete ZRC Offers or (ii) are otherwise likely to have a widespread negative impact on the results of the PRA. The Transmission Provider shall notify Market Participants and post such notice of any extension or reopening of the PRA on its website. The notice shall state the extension or

reopening's circumstances, rationale, and duration. The price associated with these ZRC Offers cannot exceed the annual CONE value divided by the number of days in the Season for the LRZ where the ZRC is represented. ZRC Offers from External Resources represented in ERZs, which are connected to single SRRZ, cannot exceed the greatest CONE value of all LRZs in respective SRRZ. ZRC Offers from External Resources represented in ERZs, which are connected to multiple SRRZs or are not connected to any SRRZs, cannot exceed the greatest CONE value of all LRZs in those connected SRRZs. Owners of ZRCs may bilaterally sell or buy ZRCs; however if a ZRC has cleared in the auction, the Market Participant that registered the Planning Resource that is the subject of such ZRC shall be responsible for complying with all Tariff requirements. The Independent Market Monitor will review the actions of owners/operators of all qualified Seasonal Accredited Capacity from Planning Resources and conversion to ZRCs to evaluate potential withholding of Planning Resources from the PRA, consistent with Module D. External Resources, including Generation Resources pseudo-tied into the MISO Balancing Authority Area, will be granted ZRCs in the applicable External Resource Zone. Notwithstanding the above, External Resources located within a Coordinating Owner that (i) borders the Transmission Provider Region; (ii) whose external ties are predominantly to the Transmission System; and (iii) has Seams Operating Agreements that allow for coordinated operations, will be granted ZRCs in the LRZ where their firm transmission service crosses the border of the Transmission Provider Region, and Border External Resources will be granted ZRCs in the LRZ where the Transmission System connects to the substation with its interconnection facilities.

Generation Resources, Intermittent Generation, Electric Storage Resources, and Dispatchable Intermittent Resources will have to meet the terms of Section 69A.3.1.g.

To the extent a Capacity Resource is located on the border of two or more LRZs (e.g., has transmission lines from two or more LRZs terminating at the substation containing the Capacity Resource's interconnection facilities), the Capacity Resource will be assigned to an LRZ as follows:

(i) if the Capacity Resource is located within the MISO BA, MISO will assign that Capacity Resource to the LRZ that contains the Local Balancing Authority in which the Capacity Resource is physically located; or

(ii) if the Capacity Resource is a Border External Resource, MISO will assign that Capacity Resource to the LRZ with which it has the greatest electrical connection. This connection will be determined by the impacts of the Resource on the system, including (i) the electrical loading of transmission facilities within and tying to the Zone and (ii) the transmission constraints which define the CIL and CEL for the Zone.

Once assigned, Capacity Resources which border two or more LRZs will not be reassigned unless significant changes occur in the Transmission Provider Region, including but not limited to, significant changes in LRZ boundaries, membership, the Transmission System, and/or Resources.

b. Participating Demand: All LSEs will be required to meet their Final PRMR through the PRA process, unless they have decided to pay the Capacity Deficiency Charge. LSEs can Self-Schedule ZRCs to meet their PRMR, consistent with the Self-

Scheduling Option in Section 69A.7.8. The Transmission Provider will conduct the PRA based upon the PRMR for the Transmission Provider Region minus the amount of PRMR associated with the Capacity Deficiency Charge, expressed as a variable reliability target through RBDCs for all of the LSEs located within the Transmission Provider Region.

c. Conducting the PRA: The Transmission Provider will conduct the PRA for each Season using the following auction procedures to determine the ACP for each LRZ and ERZ. The PRA shall be designed to commit resources equal to the Final PRMR determined by application of the RBDC for each LSE, minus the amount of PRMR associated with the Capacity Deficiency Charge but including resources used in a FRAP and an RBDC Opt Out, in each LRZ up to the total volume of offered ZRCs. All ZRCs offered at zero price will clear the PRA. The PRA shall clear for each LRZ and ERZ of the Transmission Provider Region. A multi-zone optimization methodology shall be employed to simultaneously perform the following tasks: (1) conduct the PRA to meet the supply and demand balance both for the Transmission Provider Region and for each of the First Planning Area and the Second Planning Area by clearing ZRC Offers and establishing the Final PRMR, as determined by application of the RBDCs, minus the amount of PRMR associated with the Capacity Deficiency Charge for each LRZ of the Transmission Provider Region to yield cleared ZRCs; (2) meet the LCR for each LRZ; (3) efficiently use transmission transfer capability between LRZs and from ERZs; and (4) respect the SREC and SRIC for each SRRZ, if applicable.

(i) **Objective Function:** The objective of the multi-zone optimization methodology shall be to maximize social surplus, using the as-offered overall

costs of capacity procurement and the as-bid overall benefits of capacity procurement reflected in the RBDCs over the time horizon, subject to LCR, network constraints, and SRICs and SRECs, if applicable. The overall costs will include the ZRC Offers of all Planning Resources selected for cleared ZRCs. CILs of each LRZ are simultaneous to the extent that imports into the LRZ are concurrently simulated; and CELs of each LRZ and ERZ are simultaneous to the extent that exports out of the relevant LRZ or ERZ are concurrently simulated. Network constraints will be represented by an initial set of zonal CELs and CILs, driven by the dispatch from planning models. The CELs and CILs will be reviewed by the Transmission Provider to determine if there are network loading violations when based on the geographical dispatch derived from the initial auction clearing. If no network violation is indicated, then the auction results are final. If a network violation is indicated, then reductions will be made to the affected export and import capabilities to avoid network violations and the auction will be cleared again with the new set of export and import capabilities. After a maximum of two (2) successive iterations per Season to address network violations, the auction clearing iteration with the fewest megawatts of network violations will be deemed as the final auction result.

(ii) **Time Horizon:** For purposes of clearing the system-wide PRMR the time horizon is an hour, representing the projected maximum Coincident Peak Demand. For a Local Resource Zone, the time horizon is the hour representing the Local Resource Zone Peak Demand, over each Season for the next Planning

Year for the Transmission Provider Region. Coincident Peak Demand is used to establish an LSE's Initial PRMR while Local Resource Zone Peak Demand is used to establish an LRZ's LRR.

(iii) **Capacity Market and Congestion Management:** The multi-zone optimization methodology will perform congestion management simultaneously with the scheduling of capacity for each Season in the Planning Year. Congestion management is the process where ZRCs are cleared to eliminate network constraint violations and to maximize the social surplus of procuring PRMR to meet applicable reliability standards.

(iv) **Model of Transmission Provider Transmission System:** The multi-zone optimization methodology will enforce network constraints represented by CILs, CELs and LCRs that are obtained by using a model of the transmission system including Planning Resources and Demand which will be updated annually to reflect existing and planned transmission and generation projects. Transmission and Planning Resources shall be modeled as part of the multi-zone optimization methodology to reflect their expected state during the peak Hour of each Season in the Transmission Provider Region. The model is of zonal form, which shall include all Planning Resources, Demand, and a representation of systems external to the Transmission Provider Region, and which will be consistent with seams agreements with neighboring regions.

Network Constraints. The multi-zone optimization methodology shall enforce constraints on transmission lines, transformers, and groups of

transmission branches that compose transmission interfaces represented by LCR, CIL, and CEL. Most of these constraints shall represent thermal limits on the power flow through transmission facilities. Certain constraints may impose more restrictive limits on power flow, taking into account contingencies and typically represented through operating guides.

Transmission Losses. The multi-zone optimization methodology will clear ZRCs to cover transmission losses; the PRMR will include estimates of transmission losses in its calculation for each Season.

(v) **LRZ ACP Calculation:** The Auction Clearing Price (ACP) for an LRZ is the marginal cost of serving the Demand in that LRZ. The ACP is composed of the system marginal cost of capacity, the regional marginal cost of capacity, the marginal cost of financially binding LCR, CEL, and CIL for a LRZ, (*i.e.*, network constraints that are active at the optimal solution prohibiting a lower cost outcome), and the marginal cost of financially binding SRECs and SRICs for SRRZs, if applicable. The ACP is calculated by considering the next increment or decrement to Demand for each LRZ. The Transmission Provider will calculate ACPs for each LRZ. For accounting purposes, ACP will be expressed in dollars per megawatt-day ($/MW-day).

(vi) **External Resource Zone (ERZ) ACP:** The ACP for an ERZ is comprised of the system marginal cost of capacity, marginal cost of financially binding CEL for the ERZ, the marginal cost of financially binding SRECs and SRICs for SRRZ with which the ERZ interconnects. For ERZs which connect with more than one

SRRZ, or which do not directly connect to a single SRRZ, a weighted average of the marginal cost of financially binding SREC and SRIC will be applied, with weights derived from the distribution of annual energy flows into the SRRZs from the ERZ. For accounting purposes, ACP will be expressed in dollars per megawatt-day ($/MW-day).

(vii) **ACP Inputs:** Primary inputs to the ACP calculation are network constraints represented by CIL, CEL, LCR, and other constraints established by the Transmission Provider associated with SRECs and SRICs for SRRZs in accordance with applicable seams agreements, coordination agreements, or transmission service agreements and the set of valid ZRC Offers and the Final PRMR for the Transmission Provider Region minus the amount of Initial PRMR associated with the Capacity Deficiency Charge for each LRZ. Valid ZRC Offers may include offers from ZRCs converted from confirmed Seasonal Accredited Capacity from Planning Resources. ZRC Offers can be submitted as Self-Schedules, in accordance with Section 69A.7.8.

(viii) **ACP Outputs:** For non-zero ACPs, Resources that set the ACP in a LRZ or ERZ will be cleared in proportion to the amount of ZRCs necessary to meet the Final PRMR. When more than one resource is marginal and offered at the ACP, then all resources offered at the ACP are cleared *pro rata* up to the amount required to meet the reliability requirement. This may result in a portion of multiple Resources clearing as the marginal resources that set the ACP.

(ix) **Eligibility Rules:** ACPs can be set by any ZRC Offers.

(x) **ACP for multiple Seasons with ZRC Shortage Conditions or ZRC Near-Shortage Conditions to meet Local Clearing Requirements:**

When an LRZ has more than one Season in any combination of ZRC Shortage Conditions and/or ZRC Near-Shortage Conditions the final Auction Clearing Price (ACP) for the LRZ will be set as the minimum of: (a) the original ACP as determined in Section 69A.7.1.c.(v) reflecting the effective financial binding of an LCR constraint; or (b) the summation of: (i) the amount composed of the system marginal cost of capacity, the regional marginal cost of capacity, and the marginal cost of financially binding SRECs and SRICs for SRRZs, if applicable; and (ii) the LCR price adder. The LCR price adder will be set as the amount obtained by dividing the applicable LRZ's annual CONE value by the summation of the number of days in Seasons in each Season of the Planning Year in which the LRZ was in ZRC Shortage Conditions in the Planning Resource Auction and the number of days in each Seasons of the Planning Year in which the LRZ was in ZRC Near-Shortage Conditions in the Planning Resource Auction.

(xi) **Notification:** ACPs and total summarized cleared ZRC Offers determined as described above shall be calculated and published by the Transmission Provider by 11:59 pm EST on the twentieth Business Day following the last Business Day in March. The Transmission Provider may extend the publishing deadline based on unanticipated events that: (i) interfered with the Transmission Provider's ability to receive and/or process accurate and complete ZRC Offers or (ii) were

otherwise likely to have a widespread negative impact on the results of the PRA. The Transmission Provider shall notify Market Participants and post such notice of any extension of publishing the results of the PRA on its website. The notice shall state the extension's circumstances, rationale, and duration.

Consequences of PRA

All PRA transactions will be financially binding. Market Participants with cleared ZRC Offers must comply with all of the ZRC requirements for all ZRCs that clear in the PRA.

Uncleared ZRCs

Once the PRA has concluded, a Market Participant may convert back to Seasonal Accredited Capacity any ZRCs that do not clear in the PRA.

PRA Reporting

The Transmission Provider will not reveal the ZRC Offers submitted by any Market Participant in a PRA until one (1) month following the completion of the PRA, except as required pursuant to the provisions of Section 38.9 of the Tariff. When the ZRC Offers are posted, price/quantity pairs will be made public, however the names of the Market Participants submitting such offers and the names of the Planning Resources offered shall not be publicly revealed.

Market Monitoring

All actions of Market Participants participating or failing to participate in the PRA shall be subject to the provisions of Module D, except to the extent that a Market Participant has opted out of the PRA as described in Section 69A.9. The Transmission Provider will report any known attempt to exercise market power by LSEs or by Market Participants in the PRA procedures to the Independent Market Monitor.

PRA Settlement

a. Cleared ZRC Offers will be settled at the ACP for the LRZ or ERZ where the ZRC is represented on a daily basis and the Market Participants submitting cleared ZRC Offers will be credited on a weekly basis by the Transmission Provider. The Transmission Provider will settle the LSEs cost of their Final PRMR minus the amount of PRMR associated with the Capacity Deficiency Charge at the ACP for the LRZ where the Demand is located on a daily basis and will debit LSEs weekly, to the extent that an LSE has not opted out of the PRA pursuant to Section 69A.9 or submitted an RBDC Opt Out pursuant to Section 69A.9.1. For LSEs not selecting RBDC Opt Out, the Final PRMR will be established based on the financial binding of RBDCs representing the Transmission Provider Region and applicable planning area (i.e., the First Planning Area or the Second Planning Area).

Final PRMRs will be determined as follows:

i. LSEs using the RBDC Opt Out will have Final PRMRs calculated by multiplying the LSE's forecasted Coincident Peak Demand for each Season, including transmission losses, by (1 + Transmission Provider Region PRM + RBDC Opt Out Adder).

ii. LSEs not using the RBDC Opt Out will have Final PRMRs calculated using the formula below:

$$\textit{Final PRMR for a LSE not using the RBDC Opt Out}$$
$$= \left(\textit{PRA Cleared Capacity} - \sum \textit{Final PRMR for LSEs using the RBDC Opt Out}\right) \times \frac{\textit{Initial PRMR of the LSE not using the RBDC Opt Out}}{\sum \textit{Initial PRMR of all LSEs not using the RBDC Opt Out}}$$

iii. LSEs under state jurisdiction where the State Regulatory Authority has overridden the PRM established by the Transmission Provider will have Final PRMRs for each Season calculated by multiplying the LSE's forecasted Coincident Peak Demand for each Season, including transmission losses, by (1 + the planning reserve margin established by the State Regulatory Authority).

The Transmission Provider will financially net the ZRC credits and LSE debits for Market Participants. Market Participants with cleared ZRCs sourced from Diversity Contracts will receive reduced credit for any ZRC volumes cleared above their PRMR up to the cleared volume of ZRCs from Diversity Contracts. The reduced compensation will be based on the total number of days the capacity from the Diversity Contract is dedicated to Demand in the Transmission Provider Region in each Season divided by the total number of days in the Season.

b. An LSE that submits a FRAP or an RBDC Opt Out with PRMR in an LRZ and ZRCs in an ERZ or a separate LRZ may be subject to a ZDC, as described below:

(i) The Zonal Deliverability Charge will be the maximum of: (a) the difference between the ACP for the LSE's PRMR within an LRZ where an LSE has Demand

that is not met by ZRCs from Planning Resources that are represented in such LRZ and the ACP in the LRZ or ERZ where the LSE's ZRCs are represented; or (b) zero. The Transmission Provider will multiply the ZDC by the ZRCs to obtain the deliverability charge that the Transmission Provider will assess the LSE. The Zonal Deliverability Charge will only be assessed to an LSE's Load that is part of a FRAP or for LSEs submitting ZRCs for an RBDC Opt Out.

c. Any portion of an LSE's PRMR not covered by the FRAP, minus the amount of PRMR associated with the Capacity Deficiency Charge, shall be purchased through the PRA. An LSE will be charged the applicable ACP for any PRMR that is not recovered by ZRCs in a FRAP.

d. For instances where a LRZ clears under ZRC Shortage Conditions or ZRC Near-Shortage Conditions to meet Local Clearing Requirement in more than one Season in a Planning Resource Auction and final ACPs are adjusted per Section 69A.7.1.c.(x), certain cleared ZRC Offers may exceed the final ACPs. In this case, such cleared ZRCs may be eligible for a ZRC Offer Revenue Sufficiency Credit, to the extent that settlement amounts credited in paragraph 69A.7.6.a above for a Planning Year are insufficient to cover Allowable ZRC Offer Costs, needed to be incurred by the Planning Resource to be available for cleared Seasons.

ZRC Offer Revenue Sufficiency Credit will be calculated as the greater of: (i) zero; or, (ii) the difference between Allowable ZRC Offer Costs, and the total settlement amounts credited per paragraph 69A.7.6.a for the associated cleared

ZRC Offers for all Seasons in a Planning Year.

Where Allowable ZRC Offer Costs shall equal the minimum of: (i) the sum of all cleared ZRC Offer segment volumes multiplied by the ZRC Offer segment price, multiplied by the number of Days in the Season, calculated for all Seasons for which the ZRCs clear in the Planning Resource Auction; or, (ii) the annual CONE for the LRZ where the ZRCs are represented; or, (iii) the applicable facility-specific Reference Level costs for the Planning Resource, if a Market Participant received a facility-specific Reference Level per Section 64.1.4.

ZRC Offer Revenue Sufficiency Credits will be allocated pro-rata across the Seasons where the ZRC Offer cleared for settlement and distribution.

e. ZRC Offer Revenue Sufficiency Charges will be assessed as the sum of all ZRC Offer Revenue Sufficiency Credits for a Season distributed to Market Participants representing LSEs in an LRZ clearing under ZRC Shortage Conditions or ZRC Near-Shortage Conditions on a pro rata basis, based upon their respective LSE's share of Final PRMR minus the Initial PRMR associated with the Capacity Deficiency Charge in the appropriate LRZ.

Distribution of Excess Auction Revenue

The following provisions address situations where LSEs will be entitled to receive financial benefits on contractual commitments and/or use of the Transmission System. These benefits will provide LSEs with financial hedges for ACP separation between LRZs and/or ERZs based on excess revenue from the Planning Resource Auction.

The Transmission Provider will distribute any such excess revenues in two stages:

(i) in the first stage, the Transmission Provider shall distribute such excess revenues to LSEs qualifying for Historic Unit Considerations (HUCs) as described in Section 69A.7.7(a) and ZDC Hedges as described in Section 69A.7.7.(b), then

(ii) any remaining excess revenue will be distributed in accordance with the Zonal Deliverability Benefit provisions of Section 69A.7.7(c).

The LSE will only receive excess PRA revenue if the ACP paid by the LSE is higher than the ACP received for such Planning Resources. If there are not sufficient excess revenues to fully fund all Historic Unit Considerations and ZDC Hedges, the revenues will be allocated on a pro rata basis to all HUCs and ZDC Hedges.

Historic Unit Considerations (HUCs)

The Transmission Provider will allocate excess PRA revenue to LSEs with ownership or contractual arrangements, limited to a) Grandfathered Agreements, b) arrangements that predate July 20th, 2011, or c) arrangements that predate March 26, 2018 and pertain to External Resource represented in External Resource Zones in which:

i. The LSE has Initial PRMR obligations equal to or greater than the amount of the Planning Resource designated in the arrangement;

ii. The Planning Resource designated in the arrangement and Initial PRMR obligation span multiple LRZs and/or ERZs;

iii. The LSE has long-term (five years or more) contracts for or ownership of the Planning Resource and has maintained continuous firm Transmission Service or firm Network Resource Interconnection Service, and in the case of External Resources, firm transmission service on the applicable external Balancing Authority transmission system, for that Planning Resource to the LRZ containing the LSE's associated Initial PRMR obligation; and

iv. LSEs must note qualification for HUCs and submit information supporting HUC eligibility to the Transmission Provider by January 15th prior to the upcoming Planning Year.

A combination of arrangements that require the delivery of capacity throughout the Planning Year will qualify to receive excess PRA revenue through a HUC, provided that the arrangements satisfy the criteria herein. The volume of MW eligible to receive excess PRA revenue will be the lesser of the cleared ZRCs from the Planning Resource(s) or the amount of Initial PRMR that are

associated with the qualified arrangement. A qualified arrangement shall remain eligible to receive excess PRA revenue for the current term of the executed contract, excluding any evergreen contract extension, or for two Planning Years, whichever is longer. In the event that the owned resource status is changed to retired, the transmission service is not maintained, or the arrangement is terminated or otherwise expires, the arrangement shall no longer be eligible to receive excess PRA revenue.

ZDC Hedges

An LSE will also be able to receive excess Planning Resource Auction revenue if the LSE qualifies for a ZDC Hedge. A ZDC Hedge can result from approved firm Transmission Service Request where the source and sink are in separate LRZs or between an LRZ and an ERZ that result in required Network Upgrades. The Market Participant that funds the Transmission System upgrades that result in an increase in the CIL, as determined by the Transmission Provider, for an LRZ where the sink is located, will receive a ZDC Hedge. The Market Participant submitting the Transmission Service Request will receive one hundred percent(100%) of the MW volume of the CIL increase. ZDC Hedges will be granted based upon the order that the Transmission Provider receives Transmission Service Requests. Market Participants must submit information supporting ZDC Hedges to the Transmission Provider by November 1st prior to a Planning Year. The volume of a ZDC Hedge will be the incremental increase in the CIL that resulted from the Network Upgrades identified in the approved firm Transmission Service Request. ZDC Hedges will be effective for thirty (30) years or the service life of the Transmission System facility or Network Upgrade, whichever is less.

Zonal Deliverability Benefit

If there are any remaining excess PRA revenues, the Transmission Provider will distribute the remaining amounts to Deliverability Benefit Zones.

First, the Transmission Provider will subtract PRMR and ZRCs associated with HUCs and ZDC Hedges to derive an adjusted PRMR (Adjusted PRMR) and ZRC (Adjusted ZRC). Second, the Transmission Provider shall create a DBZ for each group of LRZs that have equal ACPs which result from the same auction constraint. Third, the Transmission Provider, for each DBZ, will subtract the sum of Adjusted PRMR for each LRZ within the DBZ from the sum of Adjusted ZRCs for each LRZ within the DBZ. A DBZ will be considered a net importing DBZ if the sum of the Adjusted PRMR is greater than the sum of Adjusted ZRCs. A DBZ will be considered a net exporting DBZ if the sum of the Adjusted PRMR is less than the sum of Adjusted ZRCs. A net exporting DBZ shall not receive any ZDB credit. A net importing DBZ shall receive a ZDB credit allocation based upon a weighted average approach. Fourth, the Transmission Provider will calculate the weighted average ACP of all net exporting DBZs (Weighted Average Export ACP) to determine a financial value of export capacity within the Transmission Provider region per the formula below:

$$Weighted\ Average\ Export\ ACP = \frac{\sum(Net\ Export_j \times ACP_j)}{\sum Net\ Export_j}$$

Where j = Each net exporting DBZ

Fifth, the Transmission Provider will calculate the ZDB credit allocation, in dollars, for each net importing DBZ:

$$ZDB\ Credit_k = Net\ Import_k \times (ACP_k - Weighted\ Average\ Export\ ACP)$$

Where k = Each net importing DBZ

Finally, the Transmission Provider will distribute the ZDB credit in each DBZk by dividing the ZDB credit by the sum of Adjusted PRMR of the LRZs within each DBZk. This distribution is a credit to the initial ACP calculated for each LRZ from the PRA.

The Transmission Provider will receive FRAP and RBDC Opt Out related revenue from Zonal Deliverability Charges. The Transmission Provider will allocate such revenue to the DBZ where the PRMR associated with the ZDC is physically located. This revenue will be allocated on a *pro rata* basis by Adjusted PRMR to all LSEs within the DBZ to develop an ACP credit adjustment.

The Transmission Provider will also receive FRAP and RBDC Opt Out related revenues derived from ZRCs that would have received payments greater than the charges to the associated FRAP or RBDC Opt Out PRMR. The Transmission Provider will allocate such revenue to the DBZ where the ZRC associated with the FRAP or RBDC Opt Out is represented. This revenue will be allocated on a *pro rata* basis by Adjusted PRMR to all LSEs within the DBZ to develop an ACP credit adjustment. After calculating the ZDB rate(s), if there exists any remaining excess revenue (i.e. surplus), the surplus will be allocated back to the Deliverability Benefiting Zone(s) on a PRMR *pro-rata* basis.

Whenever an LRZ has an ACP that exceeds the System ACP because the LCR for that LRZ exceeds the sum of PRMR for LSEs within that LRZ, payments made to ZRCs in that LRZ will exceed the sum of receipts from LSEs within that LRZ plus any receipts from other LRZs related to such ZRCs. The revenue shortfall within such LRZ will be recovered from all LSEs within that LRZ on a PRMR pro-rata basis. PRMR covered by FRAPs and RBDC Opt Outs will be included in the pro-rata calculation, and the related amounts charged to the LSEs that use FRAPs and RBDC Opt Outs through this Local Clearing Requirement Charge.

Self-Scheduling Option:

LSEs with sufficient ZRCs within an LRZ where the LSE has forecasted Demand will be able to avoid the financial impact of that LRZ's ACP for the Final PRMR by Self-Scheduling such ZRCs into the PRA (*i.e.*, by Offering ZRCs into the PRA at a zero price so that the ZRCs will clear). For Planning Resources associated with ZRCs represented outside the LRZ where the LSE has PRMR, an LSE would also need to use the financial hedges described in Section 69A.7.7 to avoid the financial effects of potential price differences between LRZs or between an LRZ and an ERZ.

Installed Capacity (ICAP) Deferral Requirements and Charges

a. ICAP Deferral Notice. Market Participants that request ICAP deferral as provided in Sections 69A.3.1.a.2, 69A.3.1.b.2, 69A.3.1.c.2, and/or 69A.3.6.2. must provide an ICAP Deferral Notice to the Transmission Provider in writing by an officer of the company no later than February 15th prior to the Planning Year: (1) the expected ICAP value (in megawatts) from such Planning Resource and if the Planning Resource is new, the LBA or external BA where it is represented for any Season for which it wants to be eligible to offer ZRCs, (2) appropriate information validating that ICAP will be submitted to the Transmission Provider by the last business day of the Month prior to the start of any Season in which it wants to be eligible.

b. ICAP Deferral Credit Requirements. A Market Participant that provides ICAP Deferral Notice must satisfy credit requirements by March 1st prior to the Planning Year totaling the ICAP value provided in the ICAP Deferral Notice, multiplied by ninety (90) days of daily CONE values (i.e., 90/365 times CONE) for the LRZ where the Planning Resource is represented. If the Planning Resource is represented in an ERZ connected to a single SRRZ, the applicable CONE value will be the greatest CONE value of all LRZs in respective SRRZ. For External Resources represented in ERZs which are connected to multiple SRRZs, or which are not directly connected to any SRRZs, the applicable CONE value will be the greatest CONE value of all LRZs in those connected SRRZs. If the Market Participant: (1) submits GVTC results, demonstrates deliverability, and demonstrates commercial operation, or (2) registers replacement ZRCs in accordance with Section 69A.3.1.h, then the Transmission Provider will adjust the Market

Participant's credit requirement to account for these changes within ten (10) Business Days after ICAP is submitted or replacement ZRCs have been provided to the Transmission Provider. In the event ZRCs associated with a Planning Resource for which ICAP has been deferred are unconverted in accordance with 69A.7.3, the Market Participant may provide notice to the Transmission Provider that it wishes to forfeit the deferred ICAP value. Then the Transmission Provider will adjust the Market Participant's ICAP value and credit requirement within ten (10) Business Days.

c. ICAP Deferral Non-Compliance Charges.

i. A Market Participant that provides ICAP Deferral Notice and that either (1) has not submitted ICAP for such Planning Resources by the last business day of the Month prior to the start of any Season for which it has deferred, or (2) has submitted an ICAP value demonstrating fewer megawatts are available than the ICAP value submitted in the ICAP Deferral Notice, shall be assessed ICAP Deferral Non-Compliance Charges unless it completes ZRC replacement in accordance with Section 69A.3.1.h. Assessment of ICAP Deferral Non-Compliance Charges will commence on the first day of the any Season for which a Market Participant has an ICAP deferral and continue until ICAP is submitted and verified by the Transmission Provider, replacement ZRCs are registered per the BPM for Resource Adequacy, the ICAP value is forfeited, or the end of any deferred Season, whichever is earlier. Market Participants with Planning Resources subject to ICAP Deferral Non-Compliance Charges do not have to meet the applicable performance requirement as described in Sections 69A.3.9

and 69A.5 for such Resources, until such time that they are no longer subject to these charges.

ii. ICAP Deferral Non-Compliance Charges will be calculated as follows: the amount of ICAP that has not been submitted to the Transmission Provider multiplied by the sum of the ACP and the daily CONE value (i.e., 1/365 times CONE). The ACP and the CONE values will be based on the LRZ where the Planning Resource is represented. If the Planning Resource is represented in an ERZ connected to a single SRRZ, the applicable CONE value will be the greatest CONE value of all LRZs in respective SRRZ. For External Resources represented in ERZs which are connected to multiple SRRZs or which are not connected to any SRRZs, the applicable CONE value will be the greatest CONE value of all LRZs in those connected SRRZs.

iii. Distribution of ICAP Deferral Non-Compliance Charges: ICAP Deferral Non-Compliance Charge revenues received by the Transmission Provider will be distributed to Market Participants representing LSEs on a *pro rata* basis, based upon the LSE's share of Final PRMR minus the Initial PRMR associated with the Capacity Deficiency Charge for the Transmission Provider Region during the applicable Season.

Calculation of CONE and Net CONE

a. The CONE value shall initially be the rate proposed by the Transmission Provider in a 2012 Federal Energy Regulatory Commission filing and approved by the Commission for the Planning Year commencing on June 1, 2013. The Transmission Provider and the IMM shall consider factors, including, but not limited to: (1) physical factors (such as, the type of Generation Resource that could reasonably be constructed to provide Planning Resources, costs associated with locating the Generation Resource within the Transmission Provider Region, the estimated costs of fuel for the Generation Resource); (2) financial factors (such as, the hypothetical debt/equity ratio for the Generation Resource, the cost of capital, a reasonable return on equity, applicable taxes, interest, insurance); and (3) other costs (such as, costs related to permitting, environmental compliance, operating and maintenance expenses). In calculating the CONE, the Transmission Provider and the IMM shall not consider the anticipated net revenue from the sale of capacity, Energy or Ancillary Services. CONE values will be calculated for each LRZ. The Transmission Provider shall arrange for CONE values to be calculated in concert with the IMM no later than September 1 beginning on September 1, 2012. The recalculated CONE values shall be filed with the Commission annually thereafter.

b. The Transmission Provider shall calculate Net CONE values for each LRZ. Net CONE represents the difference between CONE values and Inframarginal Rents, for the Generation Resource type used in the CONE value calculation (the Reference Resource Type) . The following process will be used to estimate Net CONE:

To determine Inframarginal Rents, the most recent three Planning Years of historic data will be compiled for each Generation Resource of the Reference Resource Type operating in the Transmission Provider Region consisting of all revenues for the Generation Resource from the Transmission Provider's Energy and Operating Reserve Markets, on a per MW or MWh basis, whichever is applicable, calculated hourly, and Production Costs calculated hourly. The greater of the market revenues minus Production Costs, or zero, shall be calculated hourly, and summed across all Hours for each Planning Year, for each resource of the Reference Resource Type. Inframarginal Rents outside of two standard deviations from the sample mean are removed. The Generation Resources are then grouped into LRZs based on their location. An average Inframarginal Rents is calculated for each LRZ and then scaled using a capacity factor for each LRZ. The capacity factor is the ratio of the commitment hours of the Generation Resource of the Reference Resource Type that is committed for the maximum number of hours in the Planning Year amongst all Generation Resources of the Reference Resource Type to the average commitment hours of all Generation Resources of the Reference Resource Type that were committed in the LRZ in the Planning Year. This results in Inframarginal Rents values for each LRZ for each Planning Year, which will be averaged over a three-year period to determine an initial Inframarginal Rents for each LRZ.

To determine the final Inframarginal Rents values to be used for the upcoming Planning Year, the Transmission Provider will apply a scaling factor to the initial Inframarginal Rents. The scaling factor will be based on statistical models between: a) LMPs to gas, and; b) LMPs to Inframarginal Rents. Readily available settled futures gas prices for the

upcoming Planning Year will be applied to the statistical models to calculate the scaling factor.

Each LRZ's final Inframarginal Rents are then grouped and averaged into values in the First Planning Area and Second Planning Area. The values from the First Planning Area and Second Planning Area are then subtracted from the LRZ-specific CONE values to get an estimate of Net CONE for each LRZ. For use in the PRA, Net CONE values are sorted into values in the First Planning Area and Second Planning Area.

The Transmission Provider shall arrange for Net CONE values to be calculated no later than September 1 prior to the subsequent Planning Year beginning on September 1, 2024. The recalculated Net CONE values shall be filed with the Commission annually thereafter.

Use of FRAP in the Planning Resource Auction

An LSE electing to use a Fixed Resource Adequacy Plan (FRAP) in the PRA for any Season can continue to use its existing resource planning processes to meet all or any portion of its Initial PRMR by providing the Transmission Provider with a FRAP, as described below:

a. An LSE electing to use a FRAP for any Season must submit a FRAP for each LRZ to the Transmission Provider by the 7th Business Day of March prior to a Planning Year in order for the LSE to demonstrate that the LSE has designated ZRCs in order to meet all or any portion of the LSE's Initial PRMR for such LRZ. Market Participants submitting registrations for new and existing Load Modifying Resources can be included in the Module E Capacity Tracking Tool beginning as early as December prior to the Planning Year. Load Modifying Resources registrations submitted to the Transmission Provider will be evaluated to determine if Load Modifying Resources meet the qualification requirements. Market Participants that submit registrations by February 1 prior to the Planning Year will be evaluated by the Transmission Provider and will be notified of the outcome on or before February 21 that precedes the Planning Year.

Market Participants that submit registrations between February 2 and February 15 prior to the Planning Year will be evaluated by the Transmission Provider and will be notified of the outcome at least two Business Days prior to the FRAP deadline. The Transmission Provider will make a good faith effort to notify Market Participants that submit registrations after February 15 but not later than March 1 of the outcomes of such registrations no later than the FRAP deadline. The FRAP must include the LSE's forecasted Coincident Peak Demand for each LRZ for each Season and also identify the

ZRCs that the LSE owns, or has contractual rights to, in order to provide Planning Resources to meet the FRAP designated portion of its Initial PRMR and also its load ratio share of the LCR for each LRZ for each Season. The Transmission Provider will evaluate each LSE's FRAP to determine if it meets the designated portion of the LSE's Initial PRMR and the LSE's share of LCR and the Transmission Provider will notify the LSE via the MECT prior to March 15th before a Planning Year of the extent that the portion of an LSE's Initial PRMR or share of LCR for each LRZ is not covered by a submitted FRAP. The LSE will have until the PRA offer window opens to remedy any deficiencies in their FRAP for each Season.

b. To the extent that the LSE's ZRCs satisfy the portion of the LSE's Initial PRMR for the applicable Season(s) submitted through a FRAP, (1) the LSE will not have an obligation to make ZRC Offers for the ZRCs included in the FRAP into the PRA, or otherwise participate in the PRA for such Season; and (2) the LSE will not have an obligation to pay the applicable ACP for the LSE's Initial PRMR within such LRZ that is covered by the FRAP. The Transmission Provider will consider all PRMR and ZRCs, including PRMR and ZRCs in FRAPs, as part of the Transmission Provider's reliability assessment when conducting the PRA.

c. Any portion of an LSE's Initial PRMR not covered by the FRAP may be purchased through the PRA. An LSE will be charged the applicable ACP for any PRMR that is procured through the PRA.

d. If an LSE owns or controls ZRCs that are not included in the LSE's FRAP, then such LSE may submit ZRC Offers into the PRA for all such excess ZRCs, subject to Module D.

e. To the extent that an LSE designates ZRCs in a FRAP that are represented in the same LRZ as the LSE's Demand to meet the LSE's Initial PRMR for such LRZ, then the LSE will not be subject to a Zonal Deliverability Charge for such ZRCs.

f. An LSE that contains ZRCs from Planning Resources that are not represented in the same LRZ where the LSE has Demand may be subject to a Zonal Deliverability Charge, which will be calculated as described in Section 69A.7.6(b).

Use of RBDC Opt Out in the Planning Resource Auction

An LSE electing to use the RBDC Opt Out can continue to use its existing resource planning processes to meet its Final PRMR by providing the Transmission Provider with an RBDC Opt Out, as described below:

a. The RBDC Opt Out Lock-In Period will be three consecutive Planning Years for all Seasons. If an LSE fails to submit an RBDC Opt Out then the LSE will be required to participate in the PRA through any combination of the other Tariff-defined options, or pay the Capacity Deficiency Charge, for each Planning Year in which the LSE does not submit an RBDC Opt Out.

b. An LSE under state jurisdiction where the State Regulatory Authority has overridden the PRM established by the Transmission Provider is not eligible to select the RBDC Opt Out.

c. An LSE selecting the RBDC Opt Out will be required to meet its Final PRMR for the entirety of its load and losses, and its entire share of LCR for each LRZ, for each Season.

d. An LSE must provide an initial notification of its intent to elect the RBDC Opt Out no later than January 15th prior to the upcoming Planning Year. An LSE electing the RBDC Opt Out must submit its final plan for each LRZ to the Transmission Provider by the 7th Business Day of March prior to each Planning Year during the RBDC Opt Out Lock-In Period in order for the LSE to demonstrate that the LSE has designated ZRCs in order to meet the LSE's Final PRMR, and share of LCR for each LRZ, for each Season. Market Participants

using the RBDC Opt Out must submit all registrations for new and existing resources to be used in the RBDC Opt Out through the MECT consistent with the timelines established in the Business Practices Manual for Resource Adequacy. The RBDC Opt Out must include the LSE's seasonal forecasted Coincident Peak Demand for each LRZ and also identify the ZRCs that the LSE owns, or has contractual rights to, in order to provide Planning Resources to meet its Final PRMR, and also its share of the LCR for each LRZ for each Season. The Transmission Provider will evaluate each LSE's RBDC Opt Out on an annual basis to determine if it meets the LSE's Final PRMR and the LSE's share of LCR requirements for all Seasons. The Transmission Provider will notify the LSE prior to March 15th before the applicable Planning Year whether the submitted RBDC Opt Out meets the LSE's Final PRMR, and share of LCR for each LRZ, requirement for each Season during the applicable Planning Year. The LSE must remedy any deficiencies in its RBDC Opt Out for each Season before the PRA offer window opens.

e. The Transmission Provider will notify the RERRA(s) following the submission of an initial intent to elect the RBDC Opt Out by an LSE. RERRA(s) may elect to notify the Transmission Provider within twenty (20) Business Days whether the LSE's load subject to the RERRA's respective jurisdiction is authorized to select the RBDC Opt Out. Upon receipt of such a notification from the RERRA(s) that the LSE is not authorized to elect the RBDC Opt Out for the LSE's load subject to the RERRA's respective jurisdiction, the Transmission Provider will reject the

LSE's RBDC Opt Out for such load. If the Transmission Provider receives no notification from the RERRA(s) within the twenty (20) Business Day period, and an LSE has demonstrated that it has designated ZRCs in order to meet its Final PRMR, and share of LCR for each LRZ, for each Season, then the proposed RBDC Opt Out by the LSE will be deemed accepted by the Transmission Provider.

f. To the extent that the LSE's ZRCs satisfy the LSE's Final PRMR for the applicable Season(s) submitted through an RBDC Opt Out, (1) the LSE will not have an obligation to make ZRC Offers for the ZRCs included in the RBDC Opt Out into the PRA, or otherwise participate in the PRA for such Season; and (2) the LSE will not have an obligation to pay the applicable ACP for the LSE's Final PRMR within such LRZ. The Transmission Provider will consider all PRMR and ZRCs, including PRMR and ZRCs in RBDC Opt Outs, as part of the Transmission Provider's reliability assessment when conducting the PRA.

g. If an LSE owns or controls ZRCs that are not included in the LSE's RBDC Opt Out, then such LSE may submit ZRC Offers into the PRA for all such excess ZRCs, subject to Module D.

h. To the extent that an LSE designates ZRCs in an RBDC Opt Out that are represented in the same LRZ as the LSE's Demand to meet the LSE's Final PRMR for such LRZ, then the LSE will not be subject to a Zonal Deliverability Charge for such ZRCs.

i. An LSE that designates ZRCs from Planning Resources that are not represented in

the same LRZ where the LSE has Demand may be subject to a Zonal Deliverability Charge, which will be calculated as described in Section 69A.7.6(b).

j. LSEs that submit an RBDC Opt Out may not use any of the other options to satisfy their Final PRMR including: (i) submitting a Fixed Resource Adequacy Plan; (ii) Self-Scheduling ZRCs; (iii) purchasing ZRCs through the Planning Resource Auction process, and/or (iv) paying the Capacity Deficiency Charge to meet all or a portion of their Initial PRMR.

k. LSEs that elect the RBDC Opt Out that do not meet their Final PRMR shall pay the RBDC Opt Out Deficiency Charge, which is 2.748 times applicable LRZ's CONE multiplied by the difference in ZRCs between the LSEs Final PRMR and the amount of ZRCs submitted as the LSEs RBDC Opt Out for each Season in which the LSE fails to meet its Final PRMR.

l. RBDC Opt Out Deficiency Charge revenues will be distributed to Market Participants representing LSEs on a pro rata basis, based upon their respective LSE's share of Final PRMR for the Transmission Provider Region minus the Final PRMR associated with the RBDC Opt Out Deficiency Charge. If the LRZ where LSEs incurred RBDC Opt Out Deficiency Charges failed to meet its Local Clearing Requirement ("LCR"), then RBDC Opt Out Deficiency Charge revenues will be distributed to Market Participants representing LSEs on a pro rata basis, based upon their respective LSE's share of Final PRMR minus the Final PRMR associated with the RBDC Opt Out Deficiency Charge in such LRZ.

m. The Transmission Provider will determine the RBDC Opt Out Adder that will be applicable for the upcoming Planning Year every year on or before December 15. The RBDC Adder applicable during the first Planning Year in which an LSE elects to use the RBDC Opt Out will apply for such LSE's entire RBDC Opt Out Lock-In Period.

n. The Transmission Provider will determine the RBDC Opt Out Adder based on a Seasonal average of the RBDC based PRA clearing for the prior three Planning Years. If the prior year RBDC based PRA clearing is not available, simulated RBDC based PRA clearing will be used to determine the RBDC Opt Out Adder.

Capacity Deficiency Charge

a. The Transmission Provider will impose a Capacity Deficiency Charge on an LSE that has provided notification prior to the Planning Resource Auction that they will meet their Initial PRMR in part or in whole by removing Initial PRMR from the Transmission Provider's capacity construct for one or more Seasons by paying the Capacity Deficiency Charge. The Capacity Deficiency Charge will be calculated as follows: The CONE value for the LRZ(s) where the LSE has provided notice it will be meeting its Initial PRMR by paying the Capacity Deficiency Charge for each Season of the Planning Year will be multiplied by 2.748 times the Initial PRMR volume indicated by the LSE. The Capacity Deficiency Charge will be assessed to Market Participants representing their respective LSE paying the Capacity Deficiency Charge on the first Business Day after the results of the Planning Resource Auction have been published.

b. Distribution of Capacity Deficiency Charge Revenues: A Market Participant representing an LSE that provided notice it will be meeting all or part of its Initial PRMR by paying the Capacity Deficiency Charge will not be distributed any Capacity Deficiency Charge revenues for that LSE's Initial PRMR that was met by paying the Capacity Deficiency Charge. Capacity Deficiency Charge revenues received by the Transmission Provider will be distributed to Market Participants representing LSEs on a *pro rata* basis, based upon their respective LSE's share of Initial PRMR for the Transmission Provider Region minus the Initial PRMR associated with the Capacity Deficiency Charge. If the LRZ where LSEs incurred Capacity Deficiency Charges failed to meet its Local Clearing Requirement ("LCR"), then Capacity Deficiency Charge revenues will be distributed to Market Participants representing LSEs on a *pro rata* basis,

based upon their respective LSE's share of Initial PRMR minus the Initial PRMR associated with the Capacity Deficiency Charge in such LRZ.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-9

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

Exhibit 59

MISO 2025–2026 Prelim. PRA Report with Final Results

Total Installed Capacity (ICAP)	Installed Capacity (ICAP) is the lesser of a resource's net demonstrated capability submitted by the resource or its interconnection service. This field provides a summation for Local Resource Zones (LRZ), External Zones, and a MISO total. Values reflect the ICAP data as available in the Module E Capacity Tracking (MECT) tool and are subject to change the closer the Planning Resource Auction (PRA) approaches.
Total Seasonal Accredited Capacity (SAC)	SAC is the amount of Capacity, for a given Season, in MW, assigned to a Planning Resource after accounting for its historic availability. This field provides the sum of all "SAC (Max)" in the MECT based on the various accreditation methods used for each resource type by LRZ, ERZ, and a MISO total. This the maximum potential amount of capacity that is possible to be used towards meeting Resource Adequacy requirements assuming all SAC is deliverable. It is typical for not all SAC to participate in the PRA, as it is subject to Market Participant validation and confirmation and eligibility rules. This value reflects the SAC (Max) values as available in the Module E Capacity Tracking (MECT) tool. This value also reflects DR/BTMG/ER/EE which have completed and approved registrations.
Market Participant Confirmed SAC	This field reflects the "SAC (Max)" values in the MECT which have been confirmed by the Market Participants. The closer the PRA approaches the more Market Participants confirm their SAC values. SAC values must be confirmed by the Market Participant before capacity can be converted into Zonal Resource Credits (ZRCs).
Market Participant Converted SAC into Zonal Resource Credits (ZRC)	ZRCs are the fungible unit by which the PRA is conducted. ZRCs represent a MW unit of a Planning Resource that has been converted from a MW of Seasonal Accredited Capacity to a credit in the MECT, which is eligible to be offered by a Market Participant into the PRA, to be sold bilaterally, used as replacement capacity and/or to be submitted through a Fixed Resource Adequacy Plan. Once a Market Participant has confirmed their SAC values, any portion of SAC that is deliverable (NRIS or ERIS plus firm Transmission Service) may be converted into ZRCs. This field sums all SAC values that have been converted into ZRCs by Market Participants. This value is subject to change the closer the PRA approaches due to more Market Participants converting confirmed SAC into ZRCs.
Potential IMM Exclusion SAC	MISO Tariff Module D Market Monitoring Mitigation Measures, Section 64.1.1 g provides circumstances Market Participants are allowed to refuse to submit ZRC Offers into the PRA. This value reflects data in the MECT which has been uploaded by the IMM for SAC MWs seeking and/or allowed to be excluded from the PRA.
OASIS Attachment Y Approved Generation Retirement (MW)	The sum of approved & public generation retirement MW which starts in the auction period. This data is taken from the Attachment Y posting on the MISO OASIS. This value is nameplate not SAC.
Generation Suspension (MW)	The sum of approved generation suspension requested for this upcoming auction period. This value is nameplate not SAC.

BTMG Registrations In Progress	Behind the Meter Generation (BTMG) registrations that have been entered into the MECT but not yet approved. Once approved these values can propagate to the ICAP, SAC, Confirmed SAC, and ZRC tabulations contained in this report.
DR Registrations In Progress	Demand Response (DR) registrations that have been entered into the MECT but not yet approved. Once approved these values can propagate to the ICAP, SAC, Confirmed SAC, and ZRC tabulations contained in this report.
ER Registrations In Progress	External Resources (ER) registrations that have been entered into the MECT but not yet approved. Once approved these values can propagate to the ICAP, SAC, Confirmed SAC, and ZRC tabulations contained in this report.
EE Registrations In Progress	Energy Efficiency (EE) registrations that have been entered into the MECT but not yet approved. Once approved these values can propagate to the ICAP, SAC, Confirmed SAC, and ZRC tabulations contained in this report.
Sub Total of Registrations In Progress	Sums the above registrations.

Coincident Peak Forecast (CPF)	This value reflects a forecasted demand submitted with Load Serving Entities (LSE) and Electric Distribution Companies (EDC) into the MECT. CPF is the demand which is forecasted to coincide with the MISO peak.
Transmission Loss (TL) for CPF (MW)	LBA transmission loss percentages apply to the LSE's LBA Coincident Peak Demand forecast to determine the LSE's transmission losses (MW) for the calculation of the seasonal PRMR.
Initial Planning Reserve Margin Requirement (Initial PRMR)	The amount of ZRCs required of each LSE with Coincident Peak Demand in an LRZ to meet the LSE's Resource Adequacy Requirements in each Season.
Final Planning Reserve Margin Requirement (Final PRMR)	
Planning Reserve Margin Requirement (PRMR)	
Zonal Coincident Peak Forecast (ZCPF)	This value reflects a forecasted demand submitted with Load Serving Entities (LSE) and Electric Distribution Companies (EDC) into the MECT. ZCPF is the demand which is forecasted to coincide with the zonal peak.
Transmission Loss (TL) for ZCPF (MW)	LBA transmission loss percentages coincident with each LRZ's seasonal Peak Demand forecast will determine the LSE's transmission losses (MW) for the calculation of LRR (MW).

Local Clearing Requirement (LCR)	The minimum amount of Seasonal Accredited Capacity for an LRZ that is required to meet its LOLE for each Season while fully using the Zonal Import Ability for such LRZ and accounting for controllable exports.
Zonal Import Ability (ZIA)	The ability of an LRZ to import capacity from areas outside of that LRZ. Equal to an LRZ's base interchange plus the LRZ's incremental ability to import generation.
Capacity Export Limit (CEL)	The amount of Planning Resources in MWs for an LRZ or ERZ determined by the Transmission Provider that can be reliably exported from that LRZ or ERZ for each Season.
Capacity Import Limit (CIL)	The amount of Planning Resources in MWs for an LRZ determined by the Transmission Provider that can be reliably imported into that LRZ for each Season..
Local Reliability Requirement (LRR)	The minimum amount of capacity for an LRZ to meet its LOLE for each Season, without considering transmission ties to systems outside of the LRZ.
Controllable Exports	Firm capacity commitments from MISO units to non-MISO load and may be committed and dispatched by MISO during emergencies.

ACTUAL PRA DATA - PY25-26 SUMMER

2025 SUMMER

PRMR	1	2	3	4	5	6	7	8	9	10	N/C	S	Total
Coincident Peak Forecast (CPF) (MW) [M]	16,668.1	12,013.0	9,866.0	8,412.4	7,541.1	16,712.2	19,143.1	7,696.9	19,859.9	4,683.9	90,355.9	32,240.7	122,596.6
Transmission Loss (TL) for CPF (MW) [N]	439.6	211.9	226.0	148.8	133.9	419.0	530.7	169.3	354.9	82.6	2,109.9	606.8	2,716.7
Planning Reserve Margin (PRM %) [P]	7.9%	7.9%	7.9%	7.9%	7.9%	7.9%	7.9%	7.9%	7.9%	7.9%	7.9%	7.9%	7.9%
Initial Planning Reserve Margin Requirement (Initial PRMR) (MW) [Q] = [(M+N)*(1+P)]	18,459.4	13,190.2	10,889.2	9,237.6	8,281.3	18,484.8	21,228.0	8,487.8	21,812.2	5,142.9	99,770.5	35,442.9	135,213.4
"Effective" Planning Reserve Margin (PRM %) [R] = [S] / [(M+N)-1]	10.1%	10.1%	10.1%	10.1%	10.1%	10.1%	10.1%	8.7%	8.7%	8.7%	10.1%	8.7%	9.8%
Final Planning Reserve Margin Requirement (Final PRMR) (MW) [S]	18,843.5	13,464.4	11,116.0	9,430.1	8,453.5	18,868.9	21,669.2	8,552.6	21,978.8	5,182.3	101,845.6	35,713.7	137,559.3

LCR	1	2	3	4	5	6	7	8	9	10
Zonal Coincident Peak Forecast (ZCPF) [A]	17,651.7	12,192.8	10,082.7	8,538.9	7,680.0	16,769.1	19,791.9	7,989.2	20,735.3	4,752.2
Transmission Loss (TL) for ZCPF (MW) [B]	525.6	220.7	239.2	135.2	151.0	428.0	639.0	199.7	370.3	83.9
Local Resource Requirement (LRR) [C]	1.195	1.135	1.318	1.280	1.301	1.262	1.138	1.350	1.136	1.447
Zonal Import Ability (ZIA) [D]	6,023	4,370	5,460	7,757	4,117	8,366	3,569	2,358	4,361	4,474
Controllable Exports [E]	2	0	95	768	0	285	0	210	0	0
Capacity Import Limit (CIL) [F] = [(D+E)]	6,025	4,370	5,555	8,525	4,117	8,651	3,569	2,568	4,361	4,474
Local Clearing Requirement (LCR) [G] = [(A+B)*C-D-E]	15,696.9	9,719.3	8,049.3	2,577.8	6,071.1	13,051.7	19,681.4	8,487.0	19,615.0	2,523.8

CIL and CEL	1	2	3	4	5	6	7	8	9	10
Capacity Import Limit (CIL)	6,025	4,370	5,555	8,525	4,117	8,651	3,569	2,568	4,361	4,474
Capacity Export Limit (CEL)	3,991	4,614	4,618	4,584	3,939	6,881	5,726	6,299	4,286	2,097

	1	2	3	4	5	6	7	8	9	10	E20	E22	E23	E24	E26	E27	E28	Total
Total Installed Capacity (ICAP)	27,943.5	16,415.3	23,085.0	12,250.0	7,522.5	19,449.0	25,511.5	12,476.2	23,413.1	6,685.9	396.5	648.8	32.5	158.9	0.0	171.1	280.0	176,439.8
Total Seasonal Accredit Capacity (SAC)	20,183.4	14,622.0	11,582.8	9,483.1	6,795.6	16,229.2	20,918.2	11,682.6	20,635.0	5,654.9	391.7	614.2	29.5	154.6	0.0	170.9	279.9	139,427.6
Market Participant Confirmed SAC	19,992.5	14,622.0	11,470.0	9,482.9	6,795.6	16,229.2	20,916.8	11,682.6	20,629.5	5,654.1	391.7	614.2	29.5	154.6	0.0	170.9	279.9	139,116.0
Market Participant Converted UCAP into Zonal Resource Credits (ZRC)	19,855.0	14,614.8	11,395.6	9,414.9	6,758.0	16,197.6	20,885.1	11,652.3	20,557.3	5,566.6	391.7	614.2	29.5	154.6	0.0	170.9	279.6	138,537.7
Potential IMM Exclusion SAC	419.0	0.0	118.4	191.2	0.0	415.0	2.7	134.6	505.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,786.1
OASIS Attachment Y Reported MW of Approved Generation Retirement	150.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	151.0
Total Effective Suspension MW in Auction Period	0.0	0.0	0.0	0.0	0.0	0.0	43.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	43.0

ACTUAL PRA DATA - PY24-25 SUMMER

2024 SUMMER

PRMR	1	2	3	4	5	6	7	8	9	10	N/C	S	Total
Coincident Peak Forecast (CPF) (MW)	16,337.3	11,985.1	9,447.6	8,460.3	7,459.7	16,610.4	19,215.6	7,509.1	19,755.0	4,534.0	89,516.0	31,798.1	121,314.1
Transmission Loss (TL) for CPF (MW)	815.9	304.7	448.6	166.3	152.1	421.0	568.7	225.2	325.3	87.7	2,877.3	638.2	3,515.5
Planning Reserve Margin (PRM %)	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%
Planning Reserve Margin Requirement (PRMR) (MW)	18,697.0	13,395.8	10,786.8	9,402.8	8,297.0	18,564.5	21,564.7	8,430.5	21,887.6	5,037.7	100,708.6	35,355.8	136,064.4

LCR	1	2	3	4	5	6	7	8	9	10
Zonal Coincident Peak Forecast (ZCPF)	17,023.5	12,143.1	9,543.5	8,565.0	7,532.3	16,657.2	19,867.5	7,839.9	20,497.8	4,674.0
Transmission Loss (TL) for ZCPF (MW)	691.2	309.9	340.2	110.8	147.9	375.5	606.7	156.7	370.1	79.3
Controllable Exports	2	0	58	892	0	284	10	164	511	0
Local Clearing Requirement (LCR)	13,591.0	9,354.2	7,662.4	451.5	7,014.3	12,787.9	19,270.5	7,523.3	18,380.1	3,651.5

CIL and CEL	1	2	3	4	5	6	7	8	9	10
Capacity Import Limit (CIL)	6,462	4,506	4,969	10,749	3,208	7,481	4,500	3,608	5,305	3,564
Capacity Export Limit (CEL)	4,537	3,971	5,490	2,771	4,644	5,619	5,709	6,099	3,025	1,840

	1	2	3	4	5	6	7	8	9	10	E20	E22	E23	E24	E26	E27	E28	Total
Total Installed Capacity (ICAP)	28,432.6	16,352.7	23,017.0	11,838.6	8,256.6	18,890.8	26,656.0	11,460.7	24,568.5	6,505.7	395.9	1,016.3	32.2	158.9	22.0	243.9	280.0	178,128.4
Total Seasonal Accredit Capacity (SAC)	21,146.8	15,260.4	11,613.6	9,273.0	7,541.9	16,191.8	22,023.2	11,002.2	22,795.8	5,704.6	392.0	998.7	29.4	156.9	22.0	241.1	280.0	144,673.4
Market Participant Confirmed SAC	20,954.3	14,895.4	11,401.8	9,153.5	7,473.5	16,191.8	22,023.2	11,002.2	22,565.8	5,704.6	392.0	998.7	29.4	156.9	22.0	241.1	280.0	143,486.2
Market Participant Converted UCAP into Zonal Resource Credits (ZRC)	20,815.5	14,836.9	11,275.8	9,059.8	7,442.1	16,191.8	21,967.3	10,979.5	22,534.5	5,704.6	392.0	994.0	29.4	156.9	22.0	239.6	280.0	142,921.7
Potential IMM Exclusion SAC	29.6	401.2	226.4	229.6	14.2	384.7	23.7	186.3	1,172.5	0.0								2,668.2
OASIS Attachment Y Reported MW of Appoved Generation Retirement	7.8	0.0	12.0	0.0	0.0	0.0	0.0	0.0	335.0	0.0								354.8
Total Effective Suspension MW in Auction Period	0.0	0.0	0.0	24.9	0.0	0.0	0.0	0.0	257.9	0.0								282.8

ACTUAL PRA DATA POSTING - PY25-26 FALL

2025 FALL

PRMR	1	2	3	4	5	6	7	8	9	10	N/C	S	Total
Coincident Peak Forecast (CPF) (MW) [M]	14,539.8	10,319.8	8,601.1	7,610.5	6,723.2	15,049.4	17,272.0	6,835.8	18,495.8	4,402.6	80,115.8	29,734.2	109,850.0
Transmission Loss (TL) for CPF (MW) [N]	508.5	199.4	258.1	179.2	151.1	563.9	564.4	143.6	283.8	73.1	2,424.6	500.5	2,925.1
Planning Reserve Margin (PRM %) [P]	14.9%	14.9%	14.9%	14.9%	14.9%	14.9%	14.9%	14.9%	14.9%	14.9%	14.9%	14.9%	14.9%
Initial Planning Reserve Margin Requirement (Initial PRMR) (MW) [Q] = [(M+N)*(1+P)]	17,290.4	12,086.4	10,179.1	8,950.4	7,898.3	17,939.5	20,493.9	8,019.3	21,578.1	5,142.6	94,838.0	34,740.0	129,578.0
"Effective" Planning Reserve Margin (PRM %) [R] = [S] / [(M+N)-1]	18.4%	18.4%	18.4%	18.4%	18.4%	18.4%	18.4%	15.2%	15.2%	15.2%	18.4%	15.2%	17.5%
Final Planning Reserve Margin Requirement (Final PRMR) (MW) [S]	17,811.7	12,450.6	10,486.1	9,220.3	8,136.3	18,480.2	21,111.9	8,037.5	21,627.0	5,154.3	97,697.1	34,818.7	132,515.8

LCR	1	2	3	4	5	6	7	8	9	10
Zonal Coincident Peak Forecast (ZCPF) [A]	15,376.9	10,533.0	8,891.0	7,750.0	6,851.7	15,178.9	17,957.3	7,245.2	19,391.5	4,449.4
Transmission Loss (TL) for ZCPF (MW) [B]	485.7	210.1	301.2	99.8	134.5	581.3	617.3	137.6	395.3	101.4
Local Resource Requirement (LRR) [C]	1.288	1.222	1.537	1.320	1.365	1.312	1.255	1.469	1.198	1.557
Zonal Import Ability (ZIA) [D]	5,688	6,537	7,704	7,013	4,679	8,672	5,115	5,675	4,741	4,508
Controllable Exports [E]	52	0	93	760	0	280	0	164	0	0
Capacity Import Limit (CIL) [F] = [(D+E)]	5,740	6,537	7,797	7,773	4,679	8,952	5,115	5,839	4,741	4,508
Local Clearing Requirement (LCR) [G] = [(A+B)*C-D-E]	14,691.0	6,591.1	6,331.4	2,588.7	4,857.2	11,725.4	18,196.1	5,006.3	18,963.6	2,577.6

CIL and CEL	1	2	3	4	5	6	7	8	9	10
Capacity Import Limit (CIL)	5,740	6,537	7,797	7,773	4,679	8,952	5,115	5,839	4,741	4,508
Capacity Export Limit (CEL)	6,115	4,259	5,831	4,309	5,816	5,191	5,168	4,055	4,173	3,164

	1	2	3	4	5	6	7	8	9	10	E20	E22	E23	E24	E26	E27	E28	Total
Total Installed Capacity (ICAP)	26,744.9	16,212.3	23,081.8	12,151.3	7,663.1	19,066.4	24,921.1	12,268.7	23,435.7	6,667.6	375.1	670.1	32.6	158.9	0.0	171.1	280.0	173,900.7
Total Seasonal Accredit Capacity (SAC)	19,481.4	14,342.5	14,114.0	9,096.4	6,913.6	15,751.7	19,559.1	11,125.1	21,312.1	5,634.1	372.1	651.0	30.4	154.7	0.0	170.3	277.4	138,985.9
Market Participant Confirmed SAC	19,248.9	14,342.5	13,864.5	9,096.3	6,913.6	15,751.7	19,557.8	11,125.1	21,312.1	5,634.1	372.1	651.0	30.4	154.7	0.0	170.3	277.4	138,502.5
Market Participant Converted UCAP into Zonal Resource Credits (ZRC)	19,043.7	14,332.9	13,767.3	9,068.2	6,855.9	15,717.2	19,518.6	11,081.4	21,242.7	5,546.6	372.1	650.0	30.4	154.7	0.0	170.3	272.1	137,824.1
Potential IMM Exclusion SAC	391.4	0.0	126.4	183.4	0.0	649.8	3.5	88.9	550.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,993.5
OASIS Attachment Y Reported MW of Approved Generation Retirement	150.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	151.0
Total Effective Suspension MW in Auction Period	0.0	0.0	0.0	0.0	0.0	0.0	43.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	43.0

ACTUAL PRA DATA - PY24-25 FALL

2024 FALL

PRMR	1	2	3	4	5	6	7	8	9	10	N/C	S	Total
Coincident Peak Forecast (CPF) (MW)	13,807.4	10,324.4	8,511.7	7,534.4	6,839.1	15,271.0	17,008.8	6,481.7	17,834.0	4,088.9	79,296.8	28,404.6	107,701.4
Transmission Loss (TL) for CPF (MW)	425.0	184.5	195.6	96.6	139.8	289.7	410.2	175.0	251.4	70.6	1,741.4	497.0	2,238.4
Planning Reserve Margin (PRM %)	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%
Planning Reserve Margin Requirement (PRMR) (MW)	16,253.6	12,001.3	9,943.9	8,714.7	7,969.8	17,770.1	19,892.6	7,602.0	20,653.4	4,750.0	92,546.0	33,005.4	125,551.4

LCR	1	2	3	4	5	6	7	8	9	10
Zonal Coincident Peak Forecast (ZCPF)	14,773.2	10,543.9	8,715.6	7,606.5	6,911.9	15,347.7	17,752.9	6,970.4	18,780.9	4,246.3
Transmission Loss (TL) for ZCPF (MW)	481.0	191.1	226.2	154.3	168.2	331.9	434.2	139.3	328.0	83.8
Controllable Exports	2.0	0.0	62.0	895.0	0.0	298.0	10.0	195.0	501.0	0
Local Clearing Requirement (LCR)	12,336.9	7,152.3	5,280.7	3,673.5	6,416.4	10,750.3	19,443.3	5,499.1	16,630.6	2,482.3

CIL and CEL	1	2	3	4	5	6	7	8	9	10
Capacity Import Limit (CIL)	6,502	5,719	6,746	6,594	3,786	8,959	4,400	5,137	6,109	4,736
Capacity Export Limit (CEL)	5,711	4,512	6,956	3,906	5,402	3,514	5,381	4,115	2,803	2,889

	1	2	3	4	5	6	7	8	9	10	E20	E22	E23	E24	E26	E27	E28	Total
Total Installed Capacity (ICAP)	27,927.1	16,310.6	22,865.2	11,492.0	8,156.9	18,784.9	26,047.0	11,303.9	24,555.3	6,497.0	372.7	1,463.3	32.3	158.9	22.0	242.9	280.0	176,512.0
Total Seasonal Accredit Capacity (SAC)	20,210.5	14,875.4	11,224.6	8,895.6	7,415.8	16,084.2	21,193.1	10,546.4	22,803.6	5,807.4	370.4	1,371.4	30.1	153.9	22.0	240.2	280.0	141,524.6
Market Participant Confirmed SAC	20,083.5	14,638.4	11,024.7	8,776.9	7,348.2	16,084.2	21,193.1	10,546.4	22,523.3	5,807.4	370.4	1,371.4	30.1	153.9	22.0	240.2	280.0	140,494.1
Market Participant Converted UCAP into Zonal Resource Credits (ZRC)	19,938.5	14,575.2	10,875.3	8,668.7	5,562.3	16,084.2	21,072.8	10,544.3	22,502.8	5,807.4	370.4	1,362.3	30.1	153.9	22.0	237.7	280.0	138,087.9
Potential IMM Exclusion SAC	80.4	276.9	225.2	252.3	1,754.7	604.6	95.9	120.2	1,686.2	0.0								5,096.4
OASIS Attachment Y Reported MW of Approved Generation Retirement	4.9	0.0	6.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0								11.0
Total Effective Suspension MW in Auction Period	0.0	0.0	0.0	25.6	0.0	0.0	0.0	0.0	262.4	0.0								288.0

*Disclaimer - Values displayed on this posting demonstrates progress to date by Market Participants and MISO and is subject to change. The capacity displayed is not a prediction of final capacity values prior to the upcoming Planning Resource Auction. The capacity that will ultimately participate in the upcoming auction are still in progress. Capacity changes will likely stem from: Behind the Meter Generators (BTMG) / Demand Response (DR) / External Resources (ER) / Energy Efficiency (EE) programs that are still in the process of completing registration, Market Participants resolution of GVTC extensions, Market Participants utilizing ICAP Deferral, March Commercial Model updates and the March 14 deadline for Market Participants to request the IMM grant PRA exclusions as outlined in Module D Section 64.1.1 paragraph g. As per the Tariff Module E-1 Section 68A.4 and BPM-011 Appendix K, final Preliminary PRA data posting will be posted by March 25.

Data Export Time: 3/18/2025

Total (row 20), Confirmed (row 21) and Converted (row 22) SAC do not include the following: Potential IMM Exclusions (row 23), Retirements (row 24), and Suspensions (row 25).

ACTUAL PRA DATA POSTING - PY25-26 WINTER

2025-26 WINTER

PRMR	1	2	3	4	5	6	7	8	9	10	N/C	S	Total
Coincident Peak Forecast (CPF) (MW) [M]	14,605.7	8,960.7	8,087.2	7,059.4	6,547.0	14,766.6	13,277.3	7,076.0	18,032.2	4,211.9	73,303.9	29,320.1	102,624.0
Transmission Loss (TL) for CPF (MW) [N]	448.2	152.2	265.1	161.5	171.7	384.4	340.6	141.6	434.0	126.0	1,923.7	701.6	2,625.3
Planning Reserve Margin (PRM %) [P]	18.4%	18.4%	18.4%	18.4%	18.4%	18.4%	18.4%	18.4%	18.4%	18.4%	18.4%	18.4%	18.4%
Initial Planning Reserve Margin Requirement (Initial PRMR) (MW) [Q] = [(M+N)*(1+P)]	17,823.8	10,789.8	9,889.1	8,549.5	7,954.8	17,939.1	16,123.6	8,545.6	21,864.3	5,136.1	89,069.7	35,546.0	124,615.7
"Effective" Planning Reserve Margin (PRM %) [R] = [S] / [(M+N)-1]	23.3%	23.3%	23.3%	23.3%	23.3%	23.3%	23.3%	27.3%	27.3%	27.3%	23.3%	27.3%	24.5%
Final Planning Reserve Margin Requirement (Final PRMR) (MW) [S]	18,565.6	11,238.7	10,300.8	8,905.4	8,285.9	18,685.6	16,794.7	9,189.1	23,510.9	5,522.8	92,776.8	38,222.7	130,999.5

LCR	1	2	3	4	5	6	7	8	9	10
Zonal Coincident Peak Forecast (ZCPF) [A]	14,993.5	9,059.3	8,175.6	7,138.1	6,669.4	14,931.7	13,626.6	7,272.5	18,931.9	4,188.5
Transmission Loss (TL) for ZCPF (MW) [B]	506.9	159.9	332.6	116.0	162.1	306.3	376.3	152.6	352.4	106.4
Local Resource Requirement (LRR) [C]	1.267	1.353	1.632	1.186	1.254	1.247	1.447	1.566	1.297	1.628
Zonal Import Ability (ZIA) [D]	5,575	6,435	5,785	6,457	4,922	7,690	4,762	3,432	4,418	3,458
Controllable Exports [E]	602	87	92	775	0	237	0	181	0	0
Capacity Import Limit (CIL) [F] = [(D+E)]	6,177	6,522	5,877	7,232	4,922	7,927	4,762	3,613	4,418	3,458
Local Clearing Requirement (LCR) [G] = [(A+B)*C-D-E]	13,462.0	5,951.6	8,008.4	1,371.4	3,644.7	11,074.8	15,500.2	8,014.7	20,593.7	3,534.1

CIL and CEL	1	2	3	4	5	6	7	8	9	10
Capacity Import Limit (CIL)	6,177	6,522	5,877	7,232	4,922	7,927	4,762	3,613	4,418	3,458
Capacity Export Limit (CEL)	2,991	4,706	7,388	4,756	4,814	1,674	5,712	3,602	3,618	2,028

	1	2	3	4	5	6	7	8	9	10	E20	E22	E23	E24	E26	E27	E28	Total
Total Installed Capacity (ICAP)	26,213.3	14,989.9	23,093.1	11,021.5	7,399.4	18,394.5	24,923.1	11,995.8	24,737.2	6,681.8	420.1	808.7	33.8	158.9	0.0	171.1	280.0	171,322.2
Total Seasonal Accredit Capacity (SAC)	20,268.4	13,300.9	12,472.8	7,767.5	6,379.1	14,842.1	20,055.5	10,952.4	22,466.0	5,977.6	418.8	757.7	31.2	155.3	0.0	169.9	277.7	136,292.9
Market Participant Confirmed SAC	20,043.5	13,300.9	12,328.3	7,767.1	6,379.1	14,842.1	20,053.7	10,952.4	22,466.0	5,977.6	418.8	757.7	31.2	155.3	0.0	169.9	277.7	135,921.3
Market Participant Converted UCAP into Zonal Resource Credits (ZRC)	19,849.7	13,286.5	12,171.9	7,658.9	6,362.0	14,734.3	19,958.4	10,913.2	22,435.3	5,968.8	418.8	757.7	31.2	155.3	0.0	169.9	273.0	135,144.9
Potential IMM Exclusion SAC	1,042.7	629.6	83.2	198.1	0.0	845.2	39.2	105.5	502.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,446.2
OASIS Attachment Y Reported MW of Approved Generation Retirement	150.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	151.0
Total Effective Suspension MW in Auction Period	0.0	0.0	0.0	0.0	0.0	0.0	43.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	43.0

ACTUAL PRA DATA - PY24-25 WINTER

2024-25 WINTER

PRMR	1	2	3	4	5	6	7	8	9	10	N/C	S	Total
Coincident Peak Forecast (CPF) (MW)	14,085.5	8,964.9	7,918.2	7,076.2	6,328.1	14,613.6	13,217.8	6,881.4	17,102.8	3,926.1	72,204.3	27,910.3	100,114.6
Transmission Loss (TL) for CPF (MW)	457.3	222.2	423.8	223.1	245.3	441.7	413.1	165.2	317.8	98.1	2,426.5	581.1	3,007.6
Planning Reserve Margin (PRM %)	27.4	27.4	27.4	27.4	27.4	27.4	27.4	27.4	27.4	27.4	27.4	27.4	27.4
Planning Reserve Margin Requirement (PRMR) (MW)	18,527.8	11,703.9	10,628.0	9,299.5	8,374.5	19,180.0	17,365.6	8,977.1	22,193.8	5,126.6	95,079.3	36,297.5	131,376.8

LCR	1	2	3	4	5	6	7	8	9	10
Zonal Coincident Peak Forecast (ZCPF)	14,438.3	9,166.1	7,919.6	7,122.7	6,397.0	14,833.3	13,542.1	7,387.5	17,800.2	4,194.7
Transmission Loss (TL) for ZCPF (MW)	585.6	160.5	291.6	231.5	247.8	448.7	305.4	140.3	338.6	112.2
Controllable Exports	2.0	0.0	68.0	896.0	0.0	246.0	0.0	102.0	577.0	0
Local Clearing Requirement (LCR)	16,971.5	7,189.2	10,803.7	3,132.9	4,061.6	10,219.0	17,596.9	7,379.4	18,888.3	4,809.1

CIL and CEL	1	2	3	4	5	6	7	8	9	10
Capacity Import Limit (CIL)	4,693	5,523	5,668	6,707	4,477	8,532	4,656	4,364	5,200	3,219
Capacity Export Limit (CEL)	5,174	4,772	9,011	4,674	6,229	1,401	5,753	5,780	2,323	2,993

	1	2	3	4	5	6	7	8	9	10	E20	E22	E23	E24	E26	E27	E28	Total
Total Installed Capacity (ICAP)	27,590.2	15,940.1	23,123.8	11,102.2	8,382.1	18,724.5	26,387.9	11,809.3	25,616.2	6,683.8	410.1	1,644.2	33.5	158.9	22.0	161.7	280.0	178,070.4
Total Seasonal Accredit Capacity (SAC)	25,255.0	15,161.3	16,173.9	8,821.5	7,227.8	16,347.1	23,218.5	10,808.6	24,346.8	6,366.9	409.0	1,541.2	30.9	153.1	22.0	231.2	280.0	156,394.8
Market Participant Confirmed SAC	24,847.9	14,764.0	15,701.7	8,702.8	7,162.0	16,347.1	23,218.5	10,808.6	24,092.2	6,366.9	409.0	1,541.2	30.9	153.1	22.0	231.2	280.0	154,679.1
Market Participant Converted UCAP into Zonal Resource Credits (ZRC)	24,467.0	14,687.6	15,339.4	8,459.7	5,995.9	16,297.5	23,082.8	10,788.9	23,983.5	6,366.9	409.0	1,504.4	30.9	153.1	22.0	231.1	280.0	152,099.7
Potential IMM Exclusion SAC	682.9	539.4	258.5	233.8	1,154.7	339.2	21.3	102.3	1,240.3	0.0								4,572.4
OASIS Attachment Y Reported MW of Appoved Generation Retirement	19.3	0.0	29.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0								48.6
Total Effective Suspension MW in Auction Period	0.0	0.0	0.0	19.5	0.0	0.0	0.0	0.0	299.5	0.0								319.0

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Data Export Time: 3/18/2025

Total (row 20), Confirmed (row 21) and Converted (row 22) SAC do not include the following: Potential IMM Exclusions (row 23), Retirements (row 24), and Suspensions (row 25).

ACTUAL PRA DATA POSTING - PY25-26 SPRING

2026 SPRING

PRMR	1	2	3	4	5	6	7	8	9	10	N/C	S	Total
Coincident Peak Forecast (CPF) (MW) [M]	13,680.6	9,463.7	7,677.0	6,436.5	5,989.1	13,813.9	15,448.8	6,254.3	17,408.2	4,053.1	100,305.1	27,715.6	100,225.2
Transmission Loss (TL) for CPF (MW) [N]	578.1	232.1	425.2	190.8	162.7	438.4	395.8	112.6	261.3	71.2	2,858.0	445.1	2,868.2
Planning Reserve Margin (PRM %) [P]	25.3%	25.3%	25.3%	25.3%	25.3%	25.3%	25.3%	25.3%	25.3%	25.3%	25.3%	25.3%	25.3%
Initial Planning Reserve Margin Requirement (Initial PRMR) (MW) [Q] = [(M+N)*(1+P)]	17,866.7	12,149.2	10,152.2	8,304.0	7,707.9	17,858.6	19,853.2	7,977.8	22,139.8	5,167.9	93,891.8	35,285.5	129,177.3
"Effective" Planning Reserve Margin (PRM %) [R] = [S] / [(M+N)-1]	27.5%	27.5%	27.5%	27.5%	27.5%	27.5%	27.5%	25.0%	25.0%	25.0%	-7.4%	25.0%	26.8%
Final Planning Reserve Margin Requirement (Final PRMR) (MW) [S]	18,174.4	12,358.5	10,327.4	8,447.4	7,840.9	18,166.5	20,195.4	7,955.9	22,079.3	5,153.8	95,510.5	35,189.0	130,699.5

LCR	1	2	3	4	5	6	7	8	9	10
Zonal Coincident Peak Forecast (ZCPF) [A]	14,267.9	9,687.1	7,906.8	6,514.3	6,108.0	13,849.6	15,983.2	6,525.6	18,759.9	4,141.9
Transmission Loss (TL) for ZCPF (MW) [B]	414.2	212.6	181.2	151.8	165.7	440.1	407.7	110.9	315.6	77.2
Local Resource Requirement (LRR) [C]	1.283	1.331	1.588	1.495	1.459	1.388	1.319	1.587	1.292	1.788
Zonal Import Ability (ZIA) [D]	6,396	6,439	7,726	7,373	4,453	9,176	5,166	6,085	4,855	4,365
Controllable Exports [E]	202	0	103	769	0	281	0	204	0	0
Capacity Import Limit (CIL) [F] = [(D+E)]	6,598	6,439	7,829	8,142	4,453	9,457	5,166	6,289	4,855	4,365
Local Clearing Requirement (LCR) [G] = [(A+B)*C-D-E]	12,239.1	6,737.5	5,014.7	1,823.8	4,700.3	10,377.1	16,453.6	4,243.1	19,790.5	3,178.8

CIL and CEL	1	2	3	4	5	6	7	8	9	10
Capacity Import Limit (CIL)	6,598	6,439	7,829	8,142	4,453	9,457	5,166	6,289	4,855	4,365
Capacity Export Limit (CEL)	5,083	6,119	5,936	5,111	5,797	6,425	5,499	3,520	4,146	3,072

	1	2	3	4	5	6	7	8	9	10	E20	E22	E23	E24	E26	E27	E28	Total
Total Installed Capacity (ICAP)	25,715.0	16,013.6	23,303.8	12,246.7	7,052.1	18,984.1	24,160.5	12,236.7	24,512.1	6,649.8	393.3	697.6	33.5	158.9	0.0	171.1	280.0	172,608.8
Total Seasonal Accredit Capacity (SAC)	19,155.6	14,643.1	12,684.3	9,409.4	6,193.5	15,989.2	19,498.0	11,745.7	21,282.7	5,983.6	392.3	638.4	30.8	158.5	0.0	170.0	278.7	138,253.8
Market Participant Confirmed SAC	18,954.5	14,643.1	12,497.2	9,408.9	6,193.5	15,958.5	19,496.3	11,745.7	21,282.7	5,983.6	392.3	638.4	30.8	158.5	0.0	170.0	278.7	137,832.7
Market Participant Converted UCAP into Zonal Resource Credits (ZRC)	18,755.9	14,588.0	12,420.2	9,281.0	6,131.3	15,886.1	19,452.1	11,709.3	21,172.2	5,896.1	392.3	638.4	30.8	158.5	0.0	170.0	276.2	136,958.4
Potential IMM Exclusion SAC	1,051.0	257.2	87.3	220.2	655.1	1,338.2	743.4	565.8	604.8	155.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,678.4
OASIS Attachment Y Reported MW of Approved Generation Retirement	150.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	151.0
Total Effective Suspension MW in Auction Period	0.0	0.0	0.0	0.0	0.0	0.0	43.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	43.0

ACTUAL PRA DATA - PY24-25 SPRING

2025 SPRING

PRMR	1	2	3	4	5	6	7	8	9	10	N/C	S	Total
Coincident Peak Forecast (CPF) (MW)	13,193.5	9,451.0	7,650.3	6,158.0	5,953.1	13,824.5	15,167.2	6,100.0	17,149.2	4,051.0	71,397.6	27,300.2	98,697.8
Transmission Loss (TL) for CPF (MW)	394.8	164.1	235.9	141.1	133.3	261.4	357.7	128.1	266.9	79.8	1,688.3	474.8	2,163.1
Planning Reserve Margin (PRM %)	26.7%	26.7%	26.7%	26.7%	26.7%	26.7%	26.7%	26.7%	26.7%	26.7%	26.7%	26.7%	26.7%
Planning Reserve Margin Requirement (PRMR) (MW)	17,216.9	12,182.5	9,991.8	7,981.1	7,711.2	17,846.6	19,670.2	7,891.0	22,065.7	5,233.6	92,600.3	35,190.3	127,790.6

LCR	1	2	3	4	5	6	7	8	9	10
Zonal Coincident Peak Forecast (ZCPF)	13,886.7	9,657.6	7,811.1	6,200.8	6,023.0	13,903.9	15,702.2	6,453.3	18,303.8	4,274.6
Transmission Loss (TL) for ZCPF (MW)	325.3	176.3	257.7	142.1	117.6	268.6	375.9	135.6	284.7	84.5
Controllable Exports	2.0	0.0	58.0	899.0	0.0	315.0	0.0	165.0	515.0	0.0
Local Clearing Requirement (LCR)	13,944.7	8,369.6	5,781.3	4,559.9	6,043.5	11,385.5	16,372.2	4,413.1	18,684.1	3,558.4

CIL and CEL	1	2	3	4	5	6	7	8	9	10
Capacity Import Limit (CIL)	4,943	5,034	6,572	6,982	3,892	8,045	4,883	6,195	6,113	4,628
Capacity Export Limit (CEL)	6,318	4,601	5,815	5,102	4,984	3,414	5,601	4,865	4,298	2,740

	1	2	3	4	5	6	7	8	9	10	E20	E22	E23	E24	E26	E27	E28	Total
Total Installed Capacity (ICAP)	27,641.8	16,729.6	23,073.6	11,969.9	8,316.6	19,258.1	26,423.1	11,983.9	24,986.0	6,702.4	378.1	1,511.4	32.7	158.9	22.0	239.9	280.0	179,707.9
Total Seasonal Accredit Capacity (SAC)	20,182.1	15,274.4	11,357.2	9,499.6	7,337.0	16,759.3	21,524.6	11,741.1	23,303.0	6,182.4	376.7	1,455.8	30.1	155.5	22.0	235.7	280.0	145,716.5
Market Participant Confirmed SAC	19,608.0	15,010.6	11,140.9	9,377.7	7,272.2	16,759.3	21,524.6	11,741.1	23,011.7	6,182.4	376.7	1,455.8	30.1	155.5	22.0	235.7	280.0	144,184.3
Market Participant Converted UCAP into Zonal Resource Credits (ZRC)	19,427.7	14,932.0	10,995.7	9,255.7	5,862.3	16,719.3	21,268.4	11,722.4	22,974.7	6,182.4	376.7	1,437.0	30.1	155.5	22.0	233.2	280.0	141,875.1
Potential IMM Exclusion SAC	263.8	308.2	213.3	611.4	1,348.7	1,691.4	447.7	178.7	2,151.4	0.0								7,214.6
OASIS Attachment Y Reported MW of Approved Generation Retirement	7.4	0.0	9.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0								17.1
Total Effective Suspension MW in Auction Period	0.0	0.0	0.0	34.7	0.0	0.0	0.0	0.0	321.8	0.0								356.5

*Disclaimer - Values displayed on this posting demonstrates progress to date by Market Participants and MISO and is subject to change. The capacity displayed is not a prediction of final capacity values prior to the upcoming Planning Resource Auction. The capacity that will ultimately participate in the upcoming auction are still in progress. Capacity changes will likely stem from: Behind the Meter Generators (BTMG) / Demand Response (DR) / External Resources (ER) / Energy Efficiency (EE) programs that are still in the process of completing registration, Market Participants resolution of GVTC extensions, Market Participants utilizing ICAP Deferral, March Commercial Model updates and the March 14 deadline for Market Participants to request the IMM grant PRA exclusions as outlined in Module D Section 64.1.1 paragraph g. As per the Tariff Module E-1 Section 68A.4 and BPM-011 Appendix K, final Preliminary PRA data posting will be posted by March 25.

Data Export Time: 3/18/2025

Total (row 20), Confirmed (row 21) and Converted (row 22) SAC do not include the following: Potential IMM Exclusions (row 23), Retirements (row 24), and Suspensions (row 25).

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-9

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

Exhibit 60

MISO Tariff Section 38.2.7

38.2.7 Generation Suspension, Generation Retirement, and System Support Resources

a. Generator or SCU Notification of Change in Status.

(i) Notification Procedures for Units.

An owner of a Generation Resource, Synchronous Condenser Unit (SCU), or a Generator that is directly interconnected to the Transmission System but is Pseudo-tied out of the Transmission Provider's Balancing Authority Area that is planning to Suspend operations of all or any portion of that resource must notify the Transmission Provider of such a plan by submitting a completed Attachment Y Notice to the Transmission Provider. This notification provision also applies to a Generation Resource connected to the underlying lower voltage facilities within Transmission Provider region and to Generation Resources that are not directly interconnected to the Transmission System, but are External Resources that are Pseudo-tied into the Transmission Provider's Balancing Authority Area. The Transmission Provider shall coordinate with the entity to which the External Resource is directly connected to determine whether the External Resource is necessary for reliability of the Transmission System, in accordance with applicable coordinated planning provisions between the Transmission Provider and the regional planning entity to which the External Resource is interconnected.

The owner of a Generation Resource or SCU shall submit an Attachment Y Notice to the Transmission Provider at least four full Quarterly Study Periods prior to changing to Suspend status, unless the Generation Resource or SCU is inoperable due to Forced Outage in which case Attachment Y Notice must be submitted to the Transmission Provider at least thirty (30) days prior to changing to Suspend status. A Generation Resource that has undergone a Reliability Assessment Study that performs an Attachment Y equivalent study as part of the Generating

Facility Replacement process and all reliability violations identified through such study have been mitigated must submit an Attachment Y Notice to the Transmission Provider at least thirty (30) days prior to changing to Suspend status. The owner of a Pseudo-tied out Generator shall submit an Attachment Y Notice to the Transmission Provider at least thirty (30) days prior to the anticipated effective date of change of status.

A Generation Resource or SCU that is inoperable due to Forced Outage or a Pseudo-tied out Generator shall not be designated as an SSR Unit. The provisions for time limitations on suspension within Section 38.2.7 shall apply to a Generation Resource or SCU that is inoperable due to Forced Outage and a Pseudo-tied out Generator.

A Generation Resource that is designated as a Blackstart Unit by a Transmission Operator in its System Restoration Plans shall not be designated as an SSR Unit to solely provide Blackstart Service. However, the Transmission Provider may determine that SSR Unit status is justified if such Generation Resource is required to maintain the reliability of the Transmission System based on its Attachment Y Reliability Study. Section 38.2.7 shall not modify or alter a Transmission Operator’s obligations under the Tariff to identify Blackstart Units that are included in its System Restoration Plans, or a Blackstart Unit Owner's obligations to comply with the terms of any Blackstart Service agreement, in accordance with Schedule 33, or the requirements of Commission approved reliability standards.

The following exception applies to the Generation Suspension, Generation Retirement and System Support Resource (SSR) provisions in Section 38.2.7: The owner of a Generation Resource or SCU that requests a Generator Planned Outage or submits a Generator Forced Outage through the Transmission Provider’s outage scheduling system (Control Room

Operations Window – CROW or its successor) does not need to submit an Attachment Y Notice to the Transmission Provider if the request does not involve a change of status to Suspend.

An owner of a Generation Resource, SCU, or a Pseudo-tied out Generator certifies by submitting an Attachment Y Notice that it has elected to Suspend such resource and the Attachment Y Notice shall be executed by an officer of such owner attesting to that claim. The decision to Suspend may be modified by rescission as specifically provided in this Section 38.2.7.

An owner may not submit a new Attachment Y Notice to Suspend that supersedes a prior notification unless the prior Attachment Y Notice is rescinded. The new Attachment Y Notice shall be submitted to the Transmission Provider at least four full Quarterly Study Periods prior to changing to Suspend status.

(ii) Confidentiality of Attachment Y Notice.

The Transmission Provider shall treat all Attachment Y Notices as Confidential Information unless the Attachment Y Reliability Study is complete and any of the following occurs: 1) the owner has elected to waive its rescission rights; 2) the resource fails to return to operation before the period for rescission has lapsed; 3) public release is required under Section 38.2.7.b in order to evaluate the need for an SSR Agreement; or 4) the information is otherwise publicly disclosed by the owner of a Generation Resource, SCU, or a Pseudo-tied out Generator. The Transmission Provider shall promptly post on OASIS that an Attachment Y Notice was submitted, along with the effective date of retirement, under the first three of these circumstances.

(iii) Notification of the Outage Scheduler After Submittal of Attachment Y Notice.

After receipt of an Attachment Y Notice, the Transmission Provider shall schedule such outage notification through the Transmission Provider's Control Room Operations Window ("CROW") outage scheduling system, or successor system, to coordinate the outage planning of a Generation Resource or SCU through CROW, on behalf of the owner.

b. SSR Unit Procedures.

System Support Resource (SSR) procedures provide a mechanism for the Transmission Provider to enter into agreements with Market Participants that own or operate Generation Resources or Synchronous Condenser Units (SCUs) that are required by the Transmission Provider to maintain reliability of the Transmission System, if all or a specified portion of the capacity of such Generation Resources or SCUs would otherwise either Retire or Suspend. SSR Agreements are a last-resort measure to address a reliability issue on the Transmission System facilities under the functional control of the Transmission Provider and shall only be entered into once all potential SSR Agreement alternatives have been examined.

An owner of a Generation Resource or SCU must submit all necessary information to enable the Transmission Provider to evaluate whether SSR Unit status is appropriate for such Generation Resource or SCU. If, after completing a reliability study (Attachment Y Reliability Study) and analyzing potential alternatives (Attachment Y Alternatives Study), the Transmission Provider determines that SSR Unit status is justified for a Generation Resource or SCU, that is not subject to an exception under Section 38.2.7.a, then the Transmission Provider and Market Participant of such Generation Resource or SCU shall enter into an SSR Agreement, in

accordance with the Attachment Y-1 form of agreement. The SSR Unit will be operated in accordance with the terms of the SSR Agreement, which contains detailed terms and conditions regarding operation and compensation of such Generation Resource or SCU. The Transmission Provider shall periodically review the reliability requirements of the Transmission Provider Region and shall determine which, if any, SSR Agreements should be extended.

The Transmission Provider shall use reasonable efforts to respond to the owner within 150 Calendar Days after the start of the individual Attachment Y Reliability Study, regarding whether the subject of an Attachment Y Notice appears to be required for transmission system reliability, unless an alternative date is agreed to by the owner and the Transmission Provider.

If the Attachment Y Reliability Study determines that a reliability concern exists, and a response is provided by the Transmission Provider to the owner, the Transmission Provider shall promptly post on OASIS: (1) that an Attachment Y Notice was submitted; (2) that the Transmission Provider's Attachment Y Reliability Study concluded that the Generation Resource or SCU was required for the reliability of the Transmission System; (3) the draft report on the Attachment Y Reliability Study with the CEII information redacted from the report; and (4) how the associated SSR Unit costs would be allocated in the event that the Generation Resource or SCU is required to provide service under an SSR designation.

The Transmission Provider shall discontinue Confidential treatment of an Attachment Y Notice and Attachment Y Reliability Study in the event that the Attachment Y Reliability Study results determine that the Generation Resource or SCU is required to maintain system reliability and would be eligible for treatment as an SSR Unit. The Transmission Provider may use information related to Retire or Suspend status in its Transmission Planning processes (pursuant

to Attachment FF and the Transmission Planning BPM) and in its Generator Interconnection process (pursuant to Attachment X and the Generation Interconnection BPM), provided that recipients of the information have signed appropriate Non-Disclosure Agreements with the Transmission Provider.

c. Evaluation of Need for the SSR Designation.

The Transmission Provider will perform an Attachment Y Reliability Study to determine whether the Generation Resource or SCU is necessary for the reliability of the Transmission System based on the analyses described in this section and the criteria set forth in the Business Practices Manuals, but will not determine in this initial analysis the available alternatives to designating the Generation Resource or SCU as an SSR Unit. The Transmission Provider will start the study process at the beginning of the Quarterly Study Period. A request to Suspend operations submitted in an Attachment Y Notice received during a quarter will be studied individually, beginning in the subsequent Quarterly Study Period.

In collaboration with the affected Transmission Owners, the Transmission Provider will cause an evaluation to be performed of transmission system conditions (an Attachment Y Reliability Study) that result from the change in status of the unit(s) subject to Attachment Y notification requirements. The evaluation will consider the performance of the transmission system to determine if thermal or voltage violations of applicable NERC Standards and Transmission Owner planning criteria occur when the unit is offline compared to conditions when the unit is online. The scope of this evaluation will include a steady state analysis, and may require analyses of stability and import limitations for the particular study area. Study cases will be derived from approved MTEP models that are representative of the period of time for

which the suspension of the unit(s) is requested, and will include models that represent near-term and/or longer-term scenarios as appropriate for the study period. Models that are developed to reflect both the online and offline status of the unit being evaluated will be analyzed to compare the differences in results to determine the impact of the unit on the transmission system. The results of the evaluation will be reviewed with the participating Transmission Owners to verify the Transmission Provider's findings and to evaluate proposed solutions that should be considered to address the reliability issues. The need to retain a unit(s) as a System Support Resource, absent implementation of a feasible alternative, shall be determined by the presence of unresolved reliability violations on the Transmission System that is under the functional control of the Transmission Provider.

The Transmission Provider shall post the determination of reliability need on the Transmission Provider's OASIS and shall: (1) begin negotiations of a potential SSR Agreement with the Market Participant owning or operating the Generation Resource or SCU; and (2) use reasonable efforts to hold a stakeholder meeting pursuant to Attachment FF within thirty (30) Calendar Days to review alternatives to the potential SSR Unit designation or designations (if multiple Attachment Y Notices apply). The Transmission Provider will schedule subsequent stakeholder meetings as needed. The Transmission Provider shall complete the Attachment Y Alternatives Study within four full Quarterly Study Periods after receipt of an Attachment Y Notice, if the Attachment Y Notice provides only four full Quarterly Study Periods of advance notification, unless otherwise agreed to by the owner of the potential SSR Unit. If no alternative is identified as available by the Attachment Y Notice date to Suspend, then the Transmission

Provider shall file the SSR Agreement with an effective date as of the Attachment Y Notice date to Suspend.

Before entering into an SSR Agreement with any Generation Resource or SCU, the Transmission Provider shall assess, in an open and transparent planning process in accordance with the provisions of the Transmission Expansion Planning Protocol Attachment FF to the Tariff, feasible alternatives to the proposed SSR Agreement. The list of alternatives to SSR Unit status that the Transmission Provider shall consider and expeditiously approve as applicable include (depending upon the type of reliability concern identified): (i) redispatch/reconfiguration through operator instruction; (ii) remedial action plans; (iii) special protection schemes initiated upon Generation Resource trips or unplanned Transmission Outages; (iv) contracted demand response or Generator alternatives; and (v) transmission expansions. Consistent with Section B.1.b of Attachment FF, the Transmission Provider will review and evaluate alternatives to an SSR Agreement on a comparable basis and select the most appropriate solution. Comparability includes the ability of the Transmission Provider to require contractual assurances that the party who provides the alternative solution will implement the solution before the Generation Resource or SCU with the Attachment Y Notice is permitted to Retire or Suspend. The executed contractual arrangements must provide a binding arrangement that obligates the Market Participant who provides the alternative solution to complete any required infrastructure changes that are needed to avoid the reliability issues that would otherwise be addressed by transmission upgrades. While the contractual arrangements will vary based on the particular solution, the terms of the contractual arrangements must further obligate the party who provides the alternative solution to implement actions when required by the Transmission Provider to provide

necessary relief. A Generator alternative may be a new Generator, an existing Generator that is made available after the Attachment Y Reliability Study is completed, or an increase to existing Generator capacity that has an executed Generator Interconnection Agreement pursuant to Attachment X for a Commercial Operation Date that is prior to the commencement of the change of status date of the Generation Resource or SCU that has submitted an Attachment Y Notice and must be registered as a Generation Resource that is obligated to offer into the market and respond to instructions from the Transmission Provider. Contractual commitments associated with demand-side resource alternative solutions shall require demonstration to the Transmission Provider of an executed contract between LSE or ARC and Energy Consumers as well as necessary procedures and protocols for responding to Transmission Provider instructions. Such demand-side contracts must be in place by the time that the SSR Agreement alternative solution would otherwise need to be committed in order to ensure a timely solution to the identified planning need, and must be of a sufficient duration such that a reliable alternative solution can be assured. In assessing applicability for SSR status, the Transmission Provider will not require continued operation when the continued operation of a portion or all of Generation Resources or SCUs would be contrary to applicable law, regulations, or court or agency orders (such as a settlement with an environmental agency or a consent decree approved by a court). In performing the Attachment Y Reliability Study and the Attachment Y Alternatives Study to an SSR Agreement, the Transmission Provider shall collaborate with the affected Transmission Owners and NERC-registered Transmission Planners, and if appropriate, may consult with a retained consultant. The Transmission Provider will appropriately identify any Confidential Information regarding a decision to Suspend before the Transmission Provider transfers such

information to any entity. An entity that receives Confidential Information must agree in writing to maintain such confidentiality, to comply with any confidentiality obligations owed to Transmission Provider under the Tariff or pursuant to a related non-disclosure agreement, and to comply with applicable Standards of Conduct found in 18 C.F.R. § 358. The owner of the Generation Resource or SCU subject to review under this section shall make good faith efforts to minimize the costs to be incurred by seeking any available waivers or exemptions from environmental or other regulatory requirements that would necessitate improvements to the potential SSR Unit. The Transmission Provider will reasonably assist the owner of a potential SSR Unit in working with regulatory agencies to obtain environmental or other waivers or exemptions to the extent necessary to maintain the reliability of the Transmission System. For purposes of determining whether a Generation Resource or SCU qualifies as an SSR Unit, the Transmission Provider will process multiple Attachment Y Notices in the order in which the Attachment Y Notices are received. If a subsequent Attachment Y Notice is received before a determination is made for a Generation Resource or SCU that is the subject of a prior Attachment Y Notice, the Generation Resource or SCU that is the subject of a prior Attachment Y Notice will not be the subject of an SSR Agreement to avoid reliability issues caused by the subsequently noticed suspension of another Generation Resource or SCU.

The filing of a SSR Agreement with FERC shall be accompanied by a corresponding report on the Attachment Y Reliability Study and the Attachment Y Alternatives Study that details the methodologies used, study assumptions, Transmission Owner planning criteria used (including when the criteria became effective and the approving regulatory body, if any), analysis results, an evaluation of alternatives and the conclusion of the study (including a short

explanation of the proposed solution to any reliability issue identified and estimated timetables for implementing the preferred solution). An affirmation that the results, in whole or in part, from a previously filed report remain applicable may substitute for filing an entirely new report on the Attachment Y Reliability Study and the Attachment Y Alternatives Study.

d. Modification or Rescission of an Attachment Y Notice.

(i) Rescission of an Attachment Y Notice Prior to the Transmission Provider's Reliability Study Response.

The Transmission Provider shall notify the owner prior to publicizing the Attachment Y Notice and Attachment Y Reliability Study results that the Attachment Y Reliability Study is complete. However, the Transmission Provider shall not provide any information related to the Attachment Y Reliability Study results to the owner at that time. The owner may rescind its Attachment Y Notice by submitting an amended Attachment Y Notice to the Transmission Provider stating its intention, not more than fifteen (15) Business Days after receiving notice from the Transmission Provider that the Attachment Y Reliability Study is complete. In the event of such rescission, the confidentiality of the Attachment Y Notice shall be preserved.

(ii) Modification or Rescission of an Attachment Y Notice After the Owner of Generation Resource or SCU Receives the Results of Attachment Y Reliability Study, but Prior to Commencing Suspension, Retirement, or an SSR Agreement.

(1) An owner of a Generation Resource or SCU that notifies the Transmission Provider in writing of a decision to Suspend, and for which the Transmission Provider has determined that the Generation Resource or SCU is not necessary for the reliability of the

Transmission System, may rescind its decision to Suspend any time prior to the end of the period for rescission following the effective date or may modify the start of the suspension any time prior to the original effective date by submitting an amended Attachment Y Notice to the Transmission Provider stating its intention. If the revised date for suspension is prior to the original date specified in the Attachment Y Notice, a new Attachment Y Notice shall be submitted to the Transmission Provider at least four full Quarterly Study Periods prior to the effective date of suspension.

At any time during the Attachment Y Conversion Period, the owner of the Generation Resource or SCU for which the Transmission Provider has determined is not necessary for the reliability of the Transmission System, may elect to convert the Attachment Y Notice to retirement by notifying the Transmission Provider of its intent to waive the right to both rescind and modify the Attachment Y Notice. After the owner has waived the right to both rescind and modify the Attachment Y Notice, the requested status of the Generation Resource will change to Retire, and the interconnection service will be terminated in accordance with Section 38.2.7.k. The Attachment Y Notice will no longer be treated as Confidential Information once the owner has elected to waive its right to both rescind and modify the Attachment Y Notice and committed to retirement of the Generation Resource or SCU.

(2) An owner of a Generation Resource or SCU that notifies the Transmission Provider in writing of a decision to Suspend, and for which the Transmission Provider has determined that the Generation Resource or SCU is required as an SSR Unit may rescind its decision to Retire or Suspend or modify the date of suspension at any time while designated as

an SSR Unit by submitting an amended Attachment Y Notice specifying the modified effective date or stating its decision to rescind.

At any time during the Attachment Y Conversion Period, the owner of the Generation Resource or SCU for which the Transmission Provider has determined is required as an SSR Unit may elect to convert the Attachment Y Notice to retirement by notifying the Transmission Provider of its intent to waive the right to both rescind and modify the Attachment Y Notice for the initial rescission period of the Attachment Y Notice. The owner that provides such notification will retain rescission rights (*i.e.* those additionally acquired by virtue of operating as an SSR Unit) only while designated as an SSR Unit after which time the Generation Resource or SCU will have a Retire status and the interconnection service will be terminated in accordance with Section 38.2.7.k.

(iii) Modification or Rescission of an Attachment Y Notice After Commencing a Suspension, Retirement, or an SSR Agreement.

(1) An owner of a Generation Resource or SCU that notifies the Transmission Provider in writing of a decision to Suspend, and for which the resource has not been designated as an SSR Unit or is not continuing to operate pursuant to an SSR Agreement, may rescind its decision to Suspend by submitting an amended Attachment Y Notice to the Transmission Provider stating its intention to rescind any time during the period for rescission following the effective date.

At any time during the Attachment Y Conversion Period, the owner of the Generation Resource or SCU for which the Transmission Provider has determined is not necessary for the reliability of the Transmission System, may elect to convert the Attachment Y Notice to

retirement by notifying the Transmission Provider of its intent to waive the right to rescind and modify the Attachment Y Notice. After the owner has waived the right to rescind, the Generation Resource will have a Retire status, and the interconnection service will be terminated in accordance with Section 38.2.7.k. The Attachment Y Notice will no longer be treated as Confidential Information once the owner has elected to waive their right to rescind and committed to retirement of the Generation Resource or SCU.

(2) An owner of an SSR Unit may rescind its decision to Suspend or to Retire or modify the effective date prior to the termination date of the SSR Agreement by submitting an amended Attachment Y Notice specifying the modified effective date or stating its intention to rescind. After receiving an amended Attachment Y Notice from an owner of an SSR Unit to rescind or modify its decision to Suspend or to Retire, the Transmission Provider will then exercise the termination provisions of the SSR Agreement.

At any time during the Attachment Y Conversion Period, the owner of the Generation Resource or SCU for which the Transmission Provider has determined is required as an SSR Unit may elect to convert the Attachment Y Notice to retirement by notifying the Transmission Provider of its intent to waive the right to both rescind and modify the Attachment Y Notice for the initial rescission period of the Attachment Y Notice. The owner that provides such notification will retain rescission rights (*i.e.* those additionally acquired by virtue of operating as an SSR Unit) only while designated as an SSR Unit after which time the Generation Resource or SCU will have a Retire status and the interconnection service will be terminated in accordance with Section 38.2.7.k.

e. Refund of Costs.

(i) If the owner of a Generation Resource or SCU that notifies the Transmission Provider of a decision to Suspend and for which the Transmission Provider has not determined the Generation Resource or SCU is needed for reliability rescinds an Attachment Y Notice prior to commencing suspension, then such owner shall pay the Transmission Provider all of the costs that the Transmission Provider incurred in conducting an Attachment Y Reliability Study.

(ii) The Market Participant that owns or operates an SSR Unit must refund to the Transmission Provider with interest at the FERC-approved rate, all costs, less depreciation, for repairs and capital expenditures that were needed to continue operation of the Generation Resource or SCU and to meet applicable regulations and other requirements (including environmental) while the Generation Resource or SCU was subject to an SSR Agreement if the owner: (1) rescinds its decision to Suspend or to Retire the unit while it is designated a SSR; (2) rescinds its decision to Suspend following its previous designation as an SSR Unit; or **(**3**)** returns a unit to service following its previous designation as an SSR Unit and later retirement of the unit.

(iii) An owner of a Generation Resource or SCU that returns the unit to service upon failure to Retire or Suspend according to an Attachment Y Notice (*i.e*. returns from retirement or rescinds the Attachment Y Notice, including a Generation Resource or SCU that was not a SSR Unit, a former SSR Unit that no longer operates pursuant to an SSR Agreement, or an SSR Unit) will be allocated the total costs of Network Upgrades incurred or financially committed to as of the date of the notification of modification of the decision to Retire or Suspend if all the following apply:

- the rescission obviates the need for such Network Upgrades that were identified by the Transmission Provider in an Attachment Y Reliability Study;
- such Network Upgrades were necessitated solely by the Attachment Y Notice to Suspend; and
- such Network Upgrades were approved by the Transmission Provider's Board of Directors as Attachment FF Appendix A projects.

The total costs will include all pre-construction costs and interest at the FERC-approved rate. Such an owner will also be allocated the costs of expedited construction of such Network Upgrades that were approved for purposes other than dealing with needs identified in an Attachment Y Reliability Study to the extent that such expedited construction was necessitated by the Attachment Y Notice to Suspend.

In the event that multiple Attachment Y studies identified reliability issues that required the Network Upgrades and the owners of the units subject to the studies return their units to operation upon failure to Retire or Suspend (*i.e*. return from retirement or rescind the Attachment Y Notices, including Generation Resources and/or SCUs that were not SSR Units, former SSR Units that no longer operate pursuant to an SSR Agreement, or SSR Units), the owners will be allocated the total costs of such Network Upgrades incurred or financially committed to as of the date of notification of the last modification of a decision to Retire or Suspend if all the following apply:

- the rescission obviates the need for such Network Upgrades that were identified by the Transmission Provider in the Attachment Y Reliability Study;

- such Network Upgrades were necessitated solely by the Attachment Y Notice to Suspend; and
- such Network Upgrades were approved by the Transmission Provider's Board of Directors as Attachment FF Appendix A projects.

The total costs will include all pre-construction costs and interest at the FERC-approved rate. Such owners will also be allocated the costs of expedited construction of such Network Upgrades that were approved for purposes other than dealing with needs identified in an Attachment Y Reliability Study to the extent that such expedited construction was necessitated by an Attachment Y Notice to Suspend.

Except as provided in this Section, cost responsibility is assigned only for Network Upgrades that are identified to fully alleviate the violations identified in the Attachment Y Reliability Study in connection with a change in a plan to Retire or Suspend a Generation Resource or SCU. Costs of Network Upgrades that have been identified in the MTEP to address Transmission issues other than the issues identified in the Attachment Y Reliability Study of a unit that requests suspension will not be allocated to the owner of that unit if such costs of construction were not expedited as the result of an Attachment Y Notice to Suspend. In accordance with Attachment FF of the Tariff, the estimated costs of such Network Upgrades are included in the MTEP when it is approved by the Board of Directors of the Transmission Provider for inclusion in the MTEP. The Transmission Provider will solicit from the constructing Transmission Owner the actual costs (including the costs of expediting construction, and pre-construction costs, if any) incurred or committed to as of the date of notification for the last modification of a decision to Retire or Suspend. Each owner shall pay its pro rata share of

the incurred or committed Network Upgrade costs, based on the relative Generation Verification Test Capacity of each resource whose operation causes the assignment of Network Upgrade costs to its owner. The Transmission Provider will promptly notify the responsible owner of their share of the total costs once actual costs are determined.

f. Execution and Filing of SSR Agreement.

The Transmission Provider shall enter into an SSR Agreement with the Market Participant owning or operating a Generation Resource or SCU that is needed for SSR purposes based on the *pro forma* Attachment Y-1. The SSR Agreement shall state that it incorporates by reference the compensation authorized by the Commission. Resources that are ineligible to continue operating for legal or regulatory reasons, however, shall not be required to enter into an SSR Agreement. If a potential SSR Unit is ineligible or an existing SSR Unit becomes ineligible to continue operation, then the Transmission Provider shall seek to minimize the impact to Load by operating the Transmission System in the same manner as for any Resource that becomes ineligible to continue operation due to Forced Outage.

The Transmission Provider will file an SSR Agreement with the Commission for approval if the Transmission Provider's analysis determines that the Generation Resource or SCU is required for reliability of the Transmission System. All potentially affected parties will receive notification of such Commission filing. SSR service is a contracted service between the Market Participant that owns or operates an SSR Unit and the Transmission Provider and shall be for a term of twelve (12) months, unless the Transmission Provider requires a different term. The Transmission Provider must have available the entire capacity specified in the SSR Agreement of each SSR Unit.

g. Operation of SSR Unit.

Once the Transmission Provider has entered into an SSR Agreement with a Generation Resource or SCU, the Transmission Provider shall have the right to dispatch the SSR Unit at any time for reliability of the facilities within the Transmission Provider Region. The Transmission Provider shall make every attempt to minimize the use of an SSR Unit for reliability purposes. The Transmission Provider will commit the SSR Unit when conditions are identified that require the use of the SSR Unit and will make best efforts to minimize the uneconomic commitment of the SSR Unit. The SSR Agreement found in Attachment Y-1 to this Tariff shall provide for equitable compensation to an SSR Unit when it is dispatched by the Transmission Provider.

h. Scheduling Rules for SSR Units.

The Transmission Provider shall notify Market Participants with SSR Units as to the time period of Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, Short-Term Reserve, and/or Other Ancillary Services required from each SSR Unit in accordance with Section 39.1.5 for the Day-Ahead Energy and Operating Reserve Markets, Section 40.1 for Reliability Assessment Commitment processes, and Section 40.1.A.3 Look Ahead Commitment processes.

i. SSR Unit Participation in Markets.

A Market Participant may offer Energy or Ancillary Services from SSR Units into the Day-Ahead Energy and Operating Reserve Market, RAC, or Real-Time Energy and Operating Reserve Market during times when the Transmission Provider has not requested the Market Participant to run the SSR Unit at full capacity unless this would impair the ability of the SSR

Unit to provide the Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, Short-Term Reserve, or Other Ancillary Services when requested by the Transmission Provider.

Market Participants that own or operate an SSR Unit shall not use the SSR Unit to: (i) participate in Interchange Schedules; (ii) except for plant auxiliary Load obligations under the SSR Agreement, use the SSR Unit as a Self-Scheduled Resource to submit Self-Schedules for Energy and/or Operating Reserve; or (iii) submit Self-Schedules for Other Ancillary Services, if applicable, to the extent that Other Ancillary Services are required by the Transmission Provider under this Section.

j. SSR Unit Compensation.

(i) The Market Participant will be compensated for only costs incurred for the extended operation as an SSR Unit that do not exceed the full cost-of-service (including the fixed cost of existing plant). The hourly component of compensation will be provided as stated in this Tariff. For the determination of any additional compensation, the Market Participant shall submit a filing to the Commission under Section 205 of the FPA that states the additional compensation the Market Participant deems appropriate that is associated with the SSR Agreement filed by the Transmission Provider, but the Market Participant shall not separately file an SSR Agreement. The Market Participant shall provide the Transmission Provider and the Independent Market Monitor with a copy of all compensation-related filings regarding a SSR-designated unit.

(ii) Any compensation for the SSR Unit will be reduced by payments for operation of the SSR Unit, according to the provisions in this Tariff. Monthly compensation under Schedule 2 of this Tariff and payments under resource adequacy programs (a percentage of such payments

to a Market Participant whose generating unit designations are not made) shall be identified in the filing for compensation submitted by the Market Participant.

Hourly compensation will be provided for those hours in which the SSR Unit has Actual Energy Injections and the SSR Unit is committed by the Transmission Provider in the Day-Ahead Energy and Operating Reserve Market or committed by the Transmission Provider in any of the RAC processes, or in the Look Ahead Commitment ("LAC") process, including any Reliability Assessment Commitment ("RAC") process conducted prior to the Day-Ahead Energy and Operating Reserve Market, in which hours the Transmission Provider shall calculate the Market Participants' Production Cost and Operating Reserve Cost. For the purposes of this calculation, "Production Cost" means the Energy output cost pursuant to Section 39.3.2B Day-Ahead Revenue Sufficiency Guarantee Payments of the Tariff for commitments by the Transmission Provider in the Day-Ahead Energy and Operating Reserve Market or the Energy output cost pursuant to Section 40.2.19 Real-Time Sufficiency Guarantee of the Tariff for commitments by the Transmission Provider in any of the RAC processes, or in the LAC process, including any RAC process conducted prior to the Day-Ahead Energy and Operating Reserve Market, of each SSR Unit based upon Start Up, No Load, and Energy Offer cost components that reflect the actual costs of physically operating the SSR Unit(s). "Operating Reserve Cost" mean the actual cost to provide Operating Reserves. All Production Costs and Operating Reserve Costs will be subject to audit by the Transmission Provider, and will be subject to audit and enforcement by the Independent Market Monitor.

Through the Transmission Provider settlement process, the Transmission Provider will compare the "SSR Unit Compensation," which (for each SSR Unit) is equal to the sum of

Production Cost and Operating Reserve Cost, to the SSR Unit Energy, Operating Reserve Credit, and Short-Term Reserve. The SSR Unit Energy, Operating Reserve, and Short-Term Reserve Credit are those charges and credits calculated pursuant to Sections 39.3 Day-Ahead Energy and Operating Reserve Market, 40.3 Real Time Energy and Operating Reserve Market Settlement and 40.7 Determination of Inadvertent Energy of the Tariff, plus any revenues from Schedule 2 associated with the SSR Unit or from Planning Resource designation and any charges assessed through Schedule 17 and Schedule 24. In those hours where the SSR Unit Compensation is greater than the SSR Unit Energy, Operating Reserve, and Short-Term Reserve Credit for that SSR Unit, the Transmission Provider will make the applicable make-whole payment to Market Participant (such make-whole payment to be equal to the difference between the SSR Unit Compensation and the SSR Unit Energy, Operating Reserve, and Short-Term Reserve Credit). In those hours where the SSR Unit Compensation is less than the SSR Unit Energy, Operating Reserve, and Short-Term Reserve Credit, the Transmission Provider will debit from Market Participant (such debit to be equal to the difference between the SSR Unit Energy, Operating Reserve, and Short-Term Reserve Credit and the SSR Unit Compensation). If the SSR Unit receives revenue pursuant to Sections 39.3 Day-Ahead Energy and Operating Reserve Market and 40.3 Real Time Energy and Operating Reserve Market Settlement of the Tariff in hours other than those described above, the Transmission Provider will debit those revenues from the Market Participant.

(iii) The Market Participant shall file with the Commission for a Monthly SSR Payment for compensation not covered by the hourly compensation stated in the previous sub-section. The Market Participant's filing shall state the requested Monthly SSR Payment along

with its sub-components (including amounts for monthly Schedule 2 payments for each SSR Unit) and applicable cost support, including an affidavit executed by an officer of the Market Participant attesting to the accuracy of the submitted cost information. The Market Participant shall provide the Monthly SSR Payment information for each SSR Agreement, including any renewals of an SSR Agreement, and may update the information in a Section 205 filing to revise such Monthly SSR Payment following any material, unforeseen circumstances affecting the SSR Unit that changes the costs incurred by the Market Participant. The Transmission Provider shall pay the Market Participant the Monthly SSR Payment as directed by the Commission, commencing on the effective date established by the Commission.

The filing for the additional compensation should evaluate, at a minimum, the following factors in negotiating compensation for an SSR Unit: (1) operations and maintenance labor expenses directly related to the SSR Unit; (2) administrative expenses directly related to employees at the SSR Unit, including employee expenses environmental fees, safety and operator training, office supplies, communications, and plant inspection/testing expenses; (3) non-labor maintenance expenses, including chemical and materials consumed during maintenance of the SSR Unit and rental expenses for maintenance equipment used to maintain the SSR Unit; (4) taxes, permit and licensing fees, site security expenses, and insurance; (5) carrying charges**,** including charges for maintaining reasonable levels of inventories of fuel and spare parts that result from short-term operating unit decisions based on Good Utility Practice; (6) corporate expenses, including those incurred for legal services, environmental reporting, and procurement; (7) costs associated with capitalized projects; (8) depreciation, and (9) return on the undepreciated plant costs for the SSR Unit.

k. Termination of Interconnection Service.

Except as provided in Attachment X, the Transmission Provider shall file with the Commission to terminate the interconnection service to the Transmission Provider's system held by an owner of a Generation Resource or SCU or Pseudo-tied out Generator, that certifies by submitting an Attachment Y Notice that it plans to Suspend a Generation Resource or SCU or Pseudo-tied out Generator, upon the latter of: (1) the termination of an SSR Agreement; (2) the effective date for which the owner has elected to convert the Attachment Y Notice to retirement by waiving the right to rescind the decision; or (3) the end of the period for rescission for which the owner has not waived the right to rescind. Such termination of interconnection service shall be contained in a filing with the Commission and also posted by the Transmission Provider on its OASIS to the extent that such interconnection service was filed with the Commission, and shall otherwise be terminated by the Transmission Provider by a posting on its OASIS. If the owner rescinds or modifies the Attachment Y Notice in accordance with Section 38.2.7.d, the owner of such resource may retain its interconnection service and continue to operate after the conclusion of an SSR Agreement or the date specified in the Attachment Y Notice.

l. Allocation of SSR Unit Costs.

The costs pursuant to the SSR Agreement shall be allocated to the LSE(s) which require(s) the operation of the SSR Unit for reliability purposes.

m. Annual Review of SSR Unit Status.

On at least an annual basis, the Transmission Provider will review Generation Resource or SCU characteristics to determine whether the Generation Resource or SCU is qualified to remain as an SSR Unit in coordination with a review of the Transmission Provider’s annual

regional transmission expansion plan in accordance with Attachment FF. If an SSR Unit continues to be required for reliability of the Transmission System, then the Transmission Provider will have the unilateral right to negotiate and enter into a subsequent SSR Agreement by providing the Market Participant at least ninety (90) days advance notice prior to the termination date of the existing SSR Agreement and by negotiating and filing a new SSR Agreement at the Commission. If not, the SSR Agreement will expire by its own terms and the Generation Resource or SCU will lose its SSR Unit status and will resume suspension in accordance with the Attachment Y Notice or Retire. Any subsequent SSR Agreement also shall be filed with the Commission.

n. Time Limitations on Suspension.

An owner of a Generation Resource or a SCU or a Pseudo-tied out Generator may request suspension pursuant to the provisions of this Section 38.2.7 and remain for a maximum of thirty-six (36) cumulative months during any five (5) year period under any combination of suspended and SSR-designated statuses. An owner of a Generation Resource or a SCU or a Pseudo-tied out Generator that had not exhausted its maximum period may request an additional suspension period by submitting a new Attachment Y Notice four full Quarterly Study Periods prior to the effective date of the extension period, provided that the combined period is not greater than thirty-six (36) months in a five (5) year period. If a Generation Resource or a SCU or a Pseudo-tied out Generator does not return to service at the end of the thirty-six (36) month maximum suspension period, the Transmission Provider will terminate interconnection service of the resource pursuant to Section 38.2.7.

o. Non-Binding Informational Studies.

An owner of a Generation Resource or a SCU may complete an Attachment Y-2 to request that the Transmission Provider conduct a study to determine whether it is likely that a portion or all of such Generation Resource of SCU would qualify as an SSR Unit. The Transmission Provider will collaborate with the affected Transmission Owners and NERC-registered Transmission Planners, and if appropriate, will consult with a retained consultant to evaluate whether the facility is required for the reliability of the Transmission System. The Transmission Provider will appropriately identify any Confidential Information regarding a decision to Suspend that the Transmission Provider transfers to any entity. An entity that receives Confidential Information must agree in writing to maintain such confidentiality, or to any confidentiality obligations owed to Transmission Provider under the Tariff or related non-disclosure agreement, and to comply with applicable Standards of Conduct found in 18 C.F.R. § 358. The owner will not be bound to the change of status indicated in an Attachment Y-2 request. Along with a completed Attachment Y-2, such owner shall submit a study deposit of $70,000 to the Transmission Provider for the reasonable costs and expenses of such study. The Transmission Provider shall invoice such owner for all costs and expenses incurred in addition to the deposit amount, or shall refund any unused portion of such deposit upon completion of the study.

The Transmission Provider will process multiple Attachment Y-2 requests in the order in which the Attachment Y-2 requests are received. The Transmission Provider shall use reasonable efforts to submit the results of such study to the owner upon its completion within 150 days of receipt of the deposit and completed Attachment Y-2, unless an alternative period is mutually agreed to. The Transmission Provider shall treat Attachment Y-2 as Confidential

Information. If an owner rescinds an Attachment Y-2 study request, then such owner shall not receive the results of the study and the owner shall pay the Transmission Provider all of the costs incurred in conducting the study up until the date of such rescission.

Once a response is provided by the Transmission Provider to the owner, the Transmission Provider shall promptly notify the Independent Market Monitor of any Resource that may qualify as an SSR Unit. The results of such study will provide the owner with the outcome if the owner elects to submit an Attachment Y Notice to request SSR status in the future and does so in accordance with Section 38.2.7.p.

The Transmission Provider shall maintain regional power flow models pursuant to Section I.C of Attachment FF, for use by the owner of a Generation Resource or a SCU choosing to conduct a study.

p. Submission of Attachment Y Notice Following Non-Binding Reliability Studies Under Y-2.

The Attachment Y Notice following a non-binding Y-2 request must be submitted at least four full Quarterly Study Periods prior to the date of the planned change of status. The Transmission Provider shall conduct the subsequent Attachment Y process consistent with timeline and milestones in Section 38.2.7.