

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2025 Summer Reliability Assessment

May 2025



Table of Contents

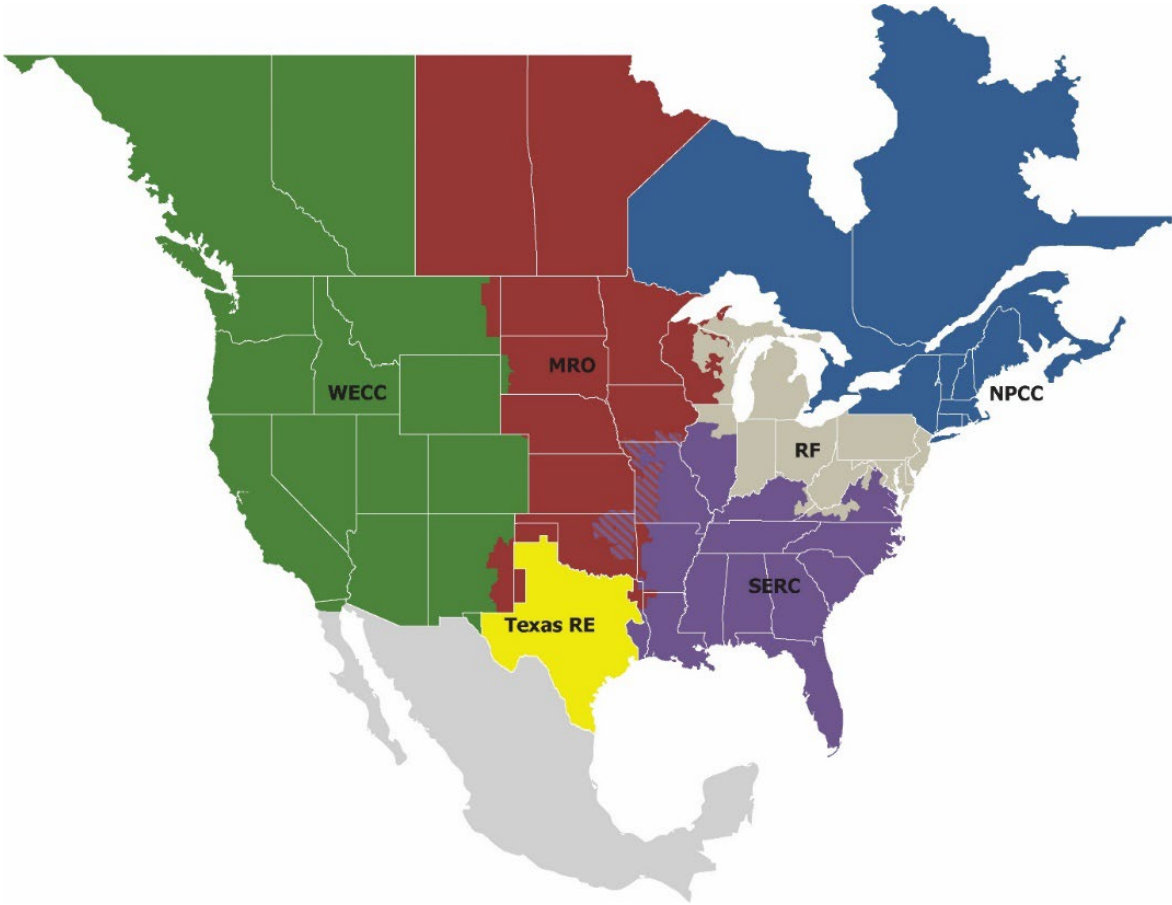
About this Assessment.....	4	Texas RE-ERCOT	30
Key Findings	5	WECC-Alberta	31
Resource Adequacy Assessment and Energy Risk Analysis.....	5	WECC-Basin.....	32
Other Reliability Issues	7	WECC-British Columbia.....	33
Recommendations	8	WECC-California	34
Summer Temperature and Drought Forecasts	9	WECC-Mexico.....	35
Risk Assessment Discussion.....	10	WECC-Rocky Mountain	36
Assessment of Planning Reserve Margins and Operational Risk Analysis.....	10	WECC-Northwest	37
MISO.....	16	WECC-Southwest	38
MRO-Manitoba Hydro	17	Data Concepts and Assumptions	39
MRO-SaskPower.....	18	Resource Adequacy.....	41
MRO-SPP	19	Changes from Year to Year	42
NPCC-Maritimes.....	20	Net Internal Demand	43
NPCC-New England	21	Demand and Resource Tables.....	44
NPCC-New York.....	22	Variable Energy Resource Contributions	50
NPCC-Ontario	23	Review of 2024 Capacity and Energy Performance	51
NPCC-Québec.....	24	Eastern Interconnection–Canada and Québec Interconnection	51
PJM.....	25	Eastern Interconnection–United States.....	51
SERC-Central	26	Texas Interconnection–ERCOT	52
SERC-East	27	Western Interconnection	52
SERC-Florida Peninsula	28	Western Interconnection–Canada	52
SERC-Southeast	29	Western Interconnection–United States.....	52

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.

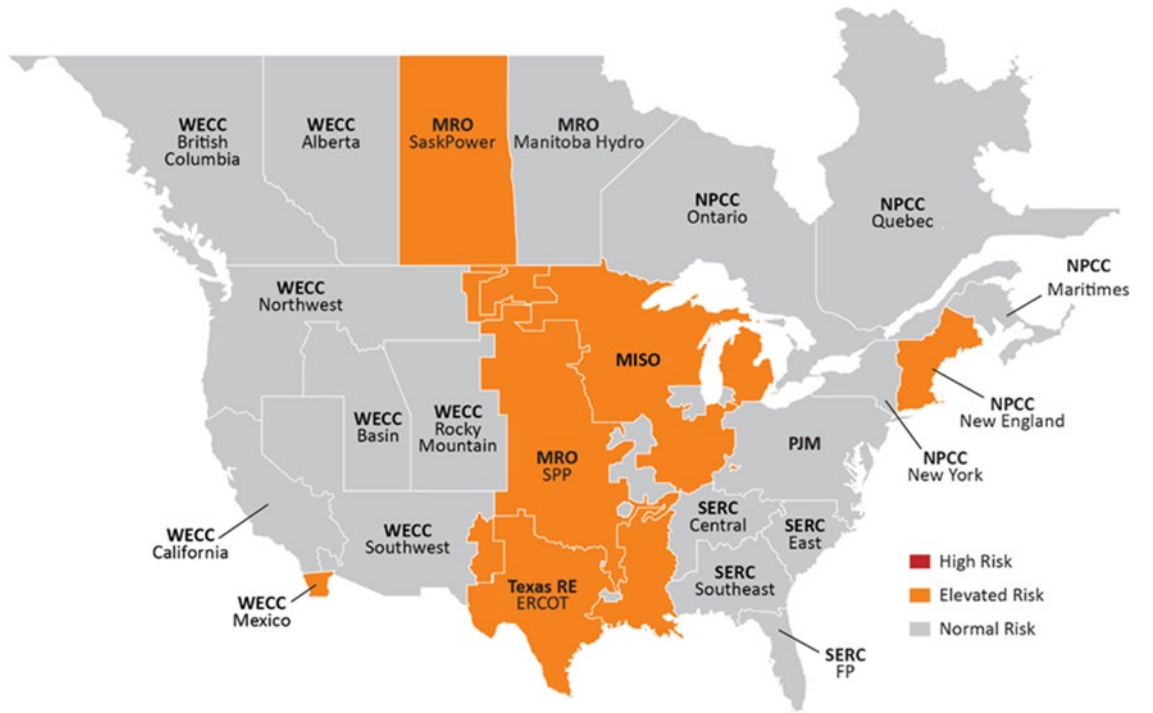


Figure 1: Summer Reliability Risk Area Summary

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.

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.

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.⁹
 - 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.

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.

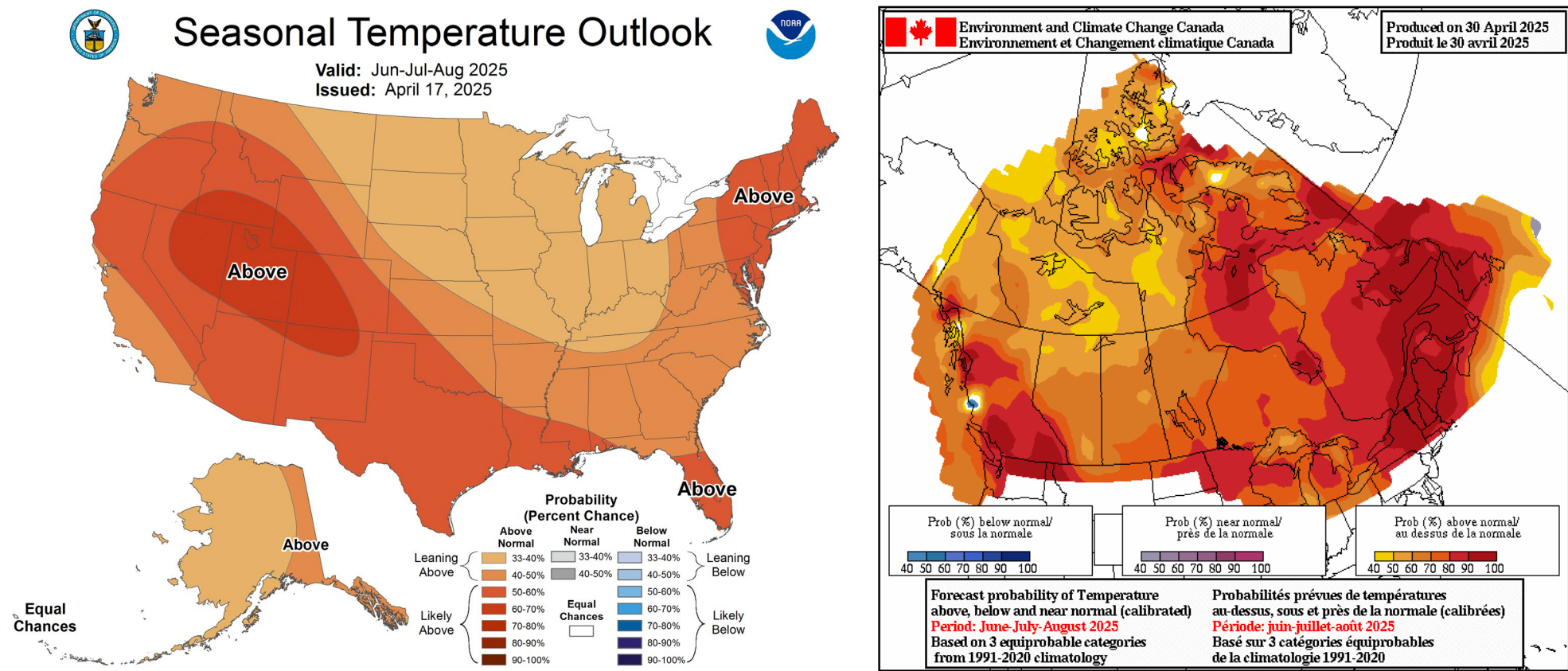


Figure 2: United States and Canada Summer Temperature Outlook¹⁰

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	- 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 scenarios²
Potential for insufficient operating reserves in normal peak conditions	
Elevated	- 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
Potential for insufficient operating reserves in above-normal conditions	
Normal	- 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 scenarios⁴
Sufficient operating reserves expected	
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

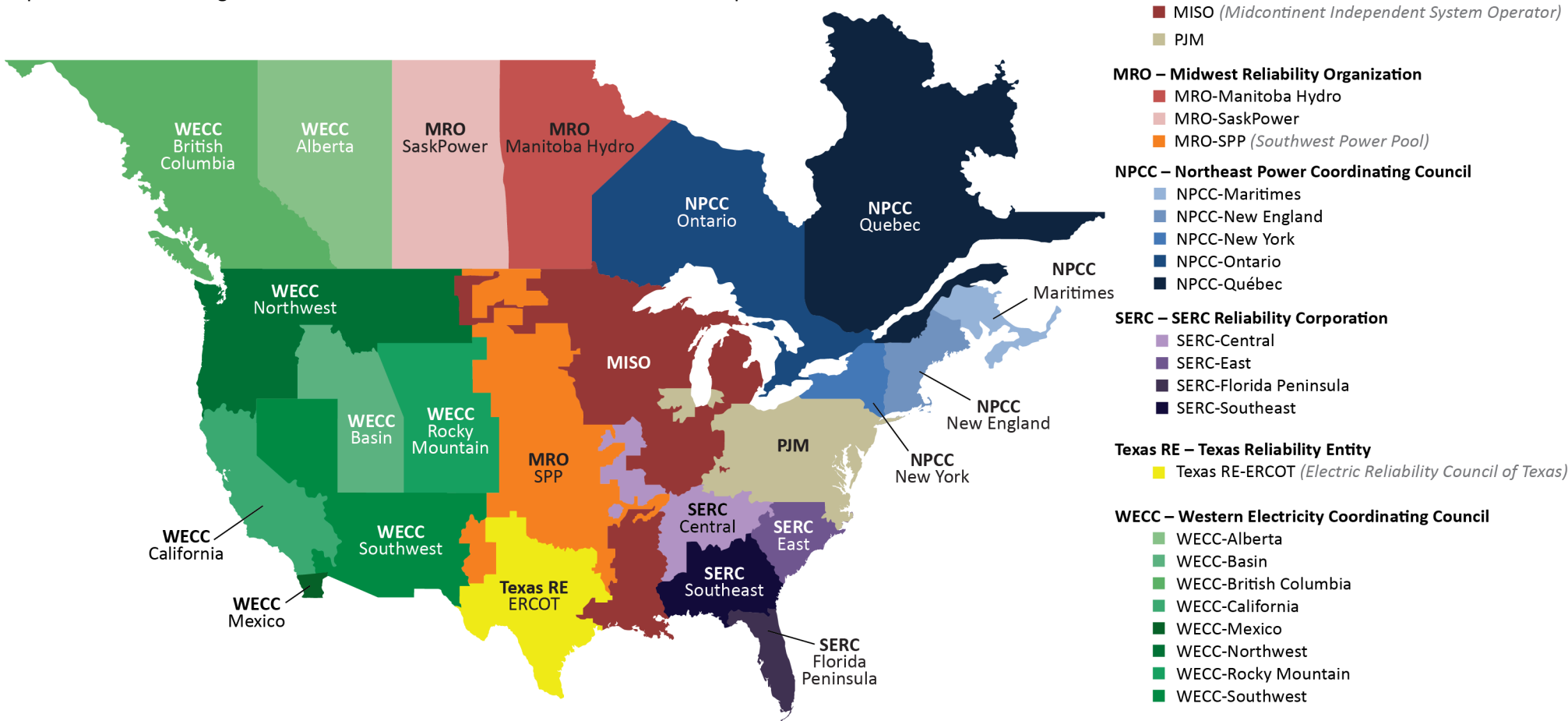
Assessment Area	Type of Assessment	Results and Insight from Assessment
NPCC-Ontario		NPCC’s preliminary result of this assessment indicates that the low-likelihood resource case, highest peak load level conditions resulted in a negligible cumulative LOLE (0.081 days/period), with associated cumulative 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.

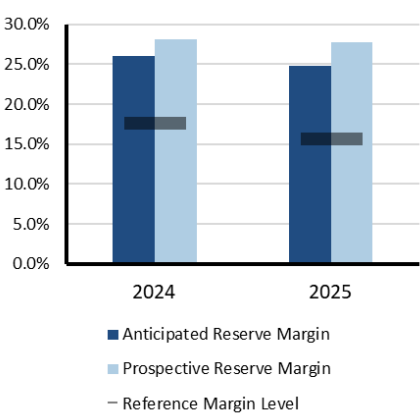
Highlights

- 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.

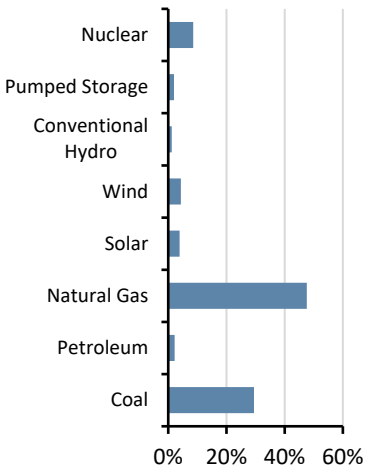
Risk Scenario Summary

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.

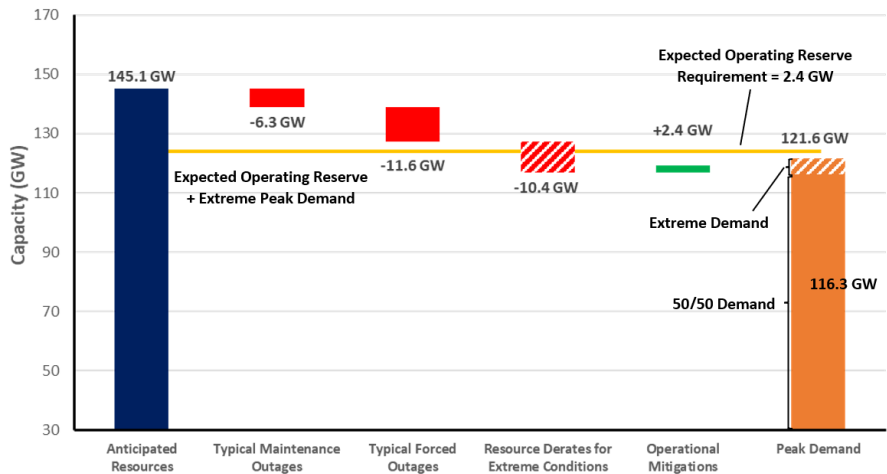
On-Peak Reserve Margin



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 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.

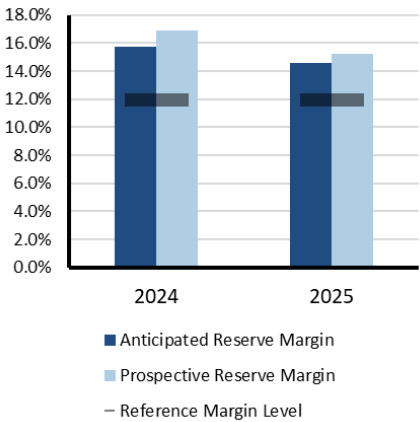
Highlights

- 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.

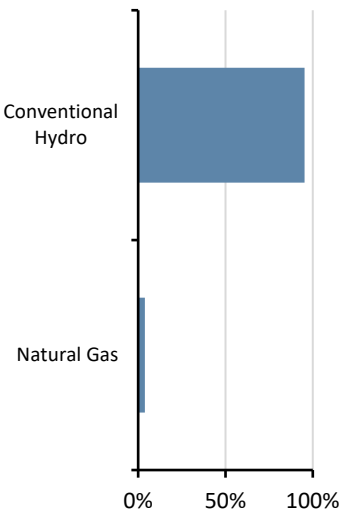
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

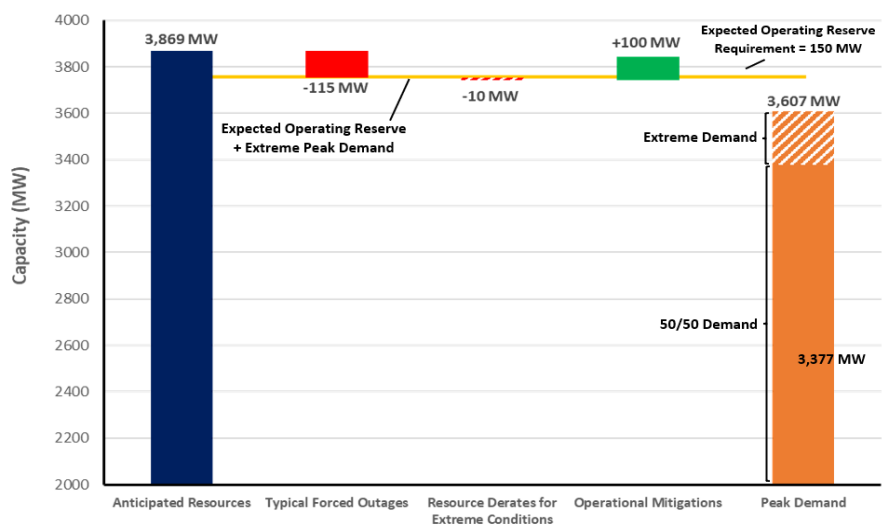
On-Peak Reserve Margin



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

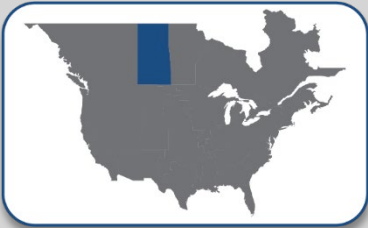
Demand Scenarios: (50/50) Demand with allowance for extreme demand based on extreme summer weather scenario of 35.4 C (96 F)

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.

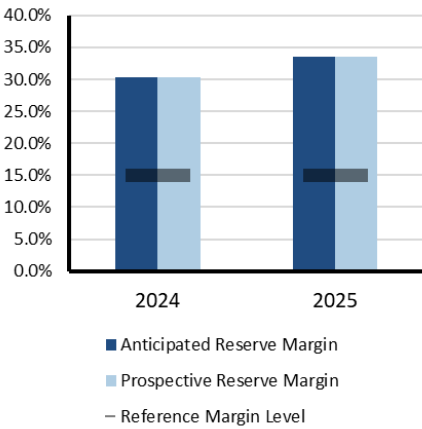
Highlights

- 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.

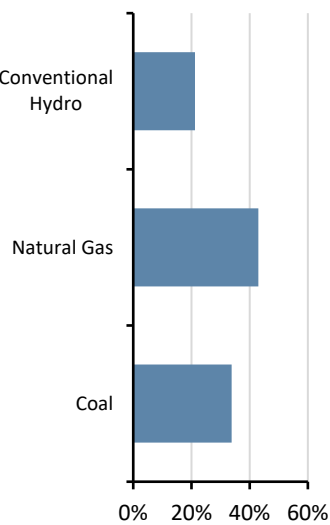
Risk Scenario Summary

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.

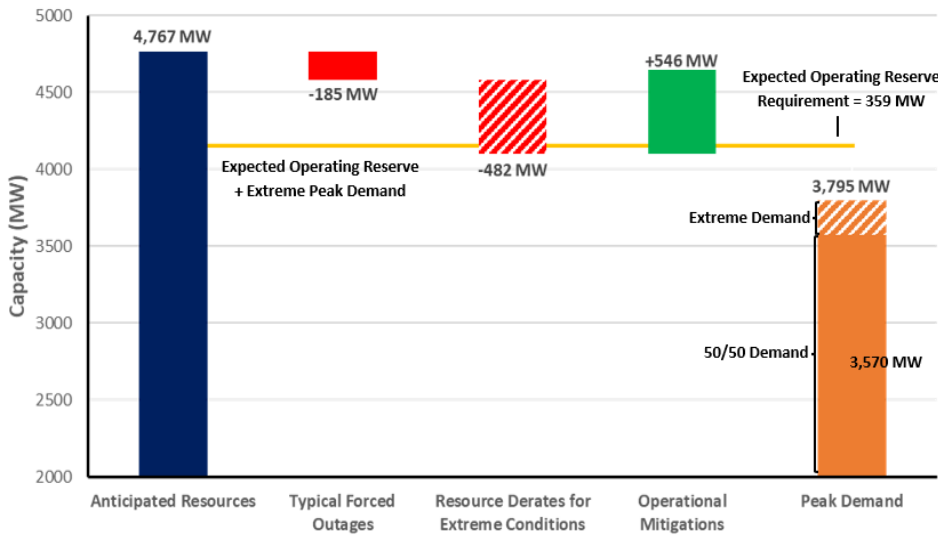
On-Peak Reserve Margin



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.

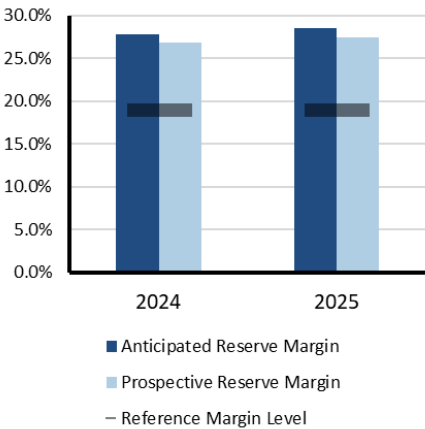
Highlights

- 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.

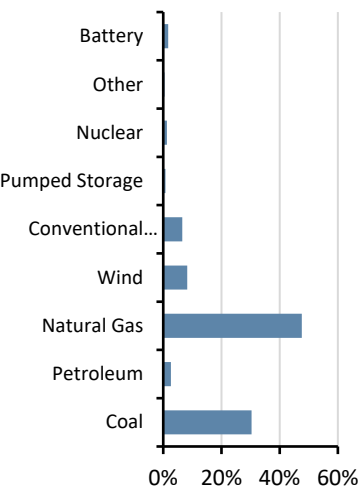
Risk Scenario Summary

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.

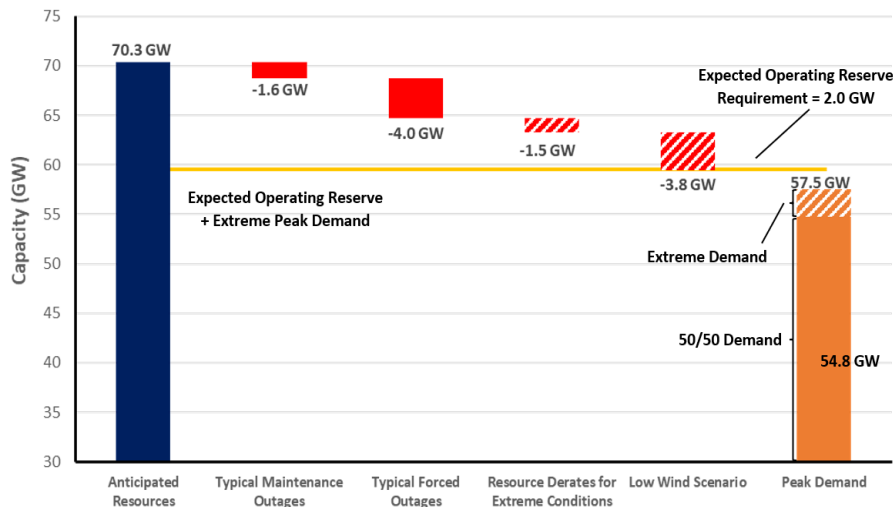
On-Peak Reserve Margin



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 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.

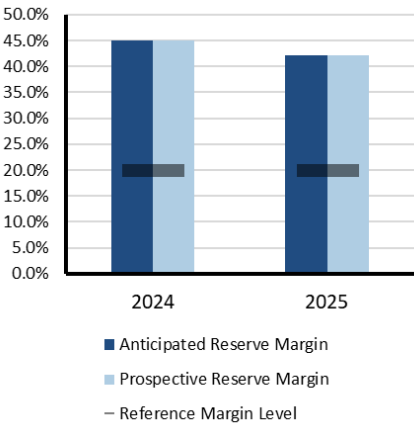
Highlights

- 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.

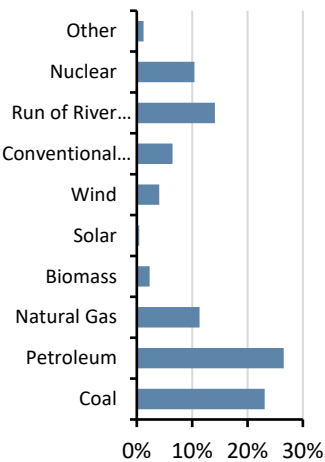
Risk Scenario Summary

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.

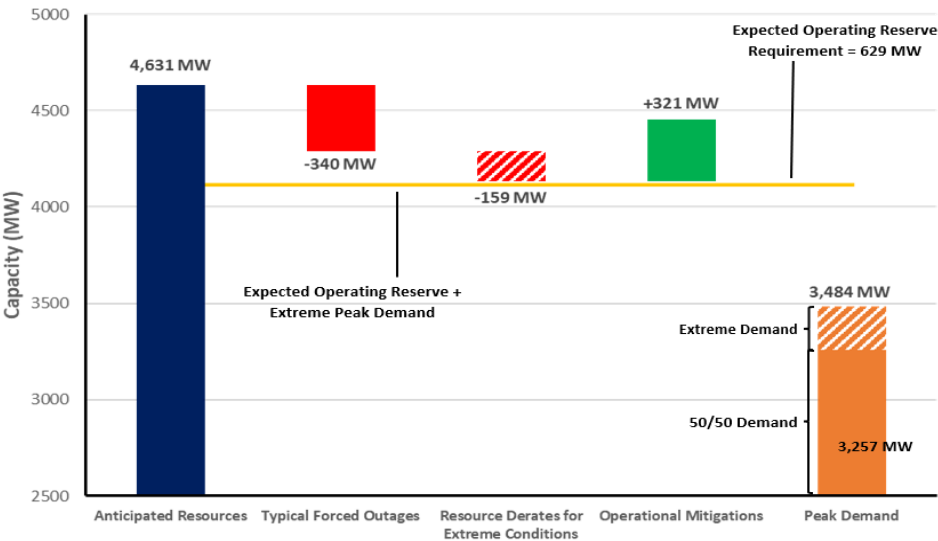
On-Peak Reserve Margin



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 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.

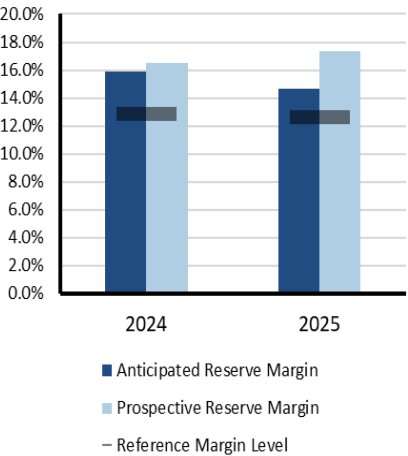
Highlights

- 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](#).

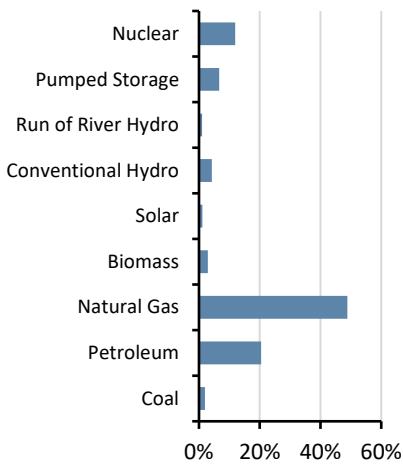
Risk Scenario Summary

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.

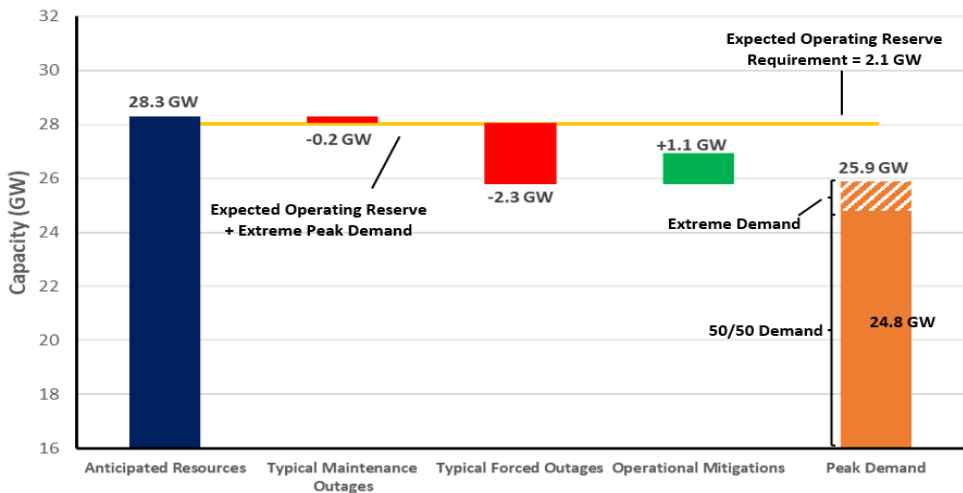
On-Peak Reserve Margin



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: 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%.

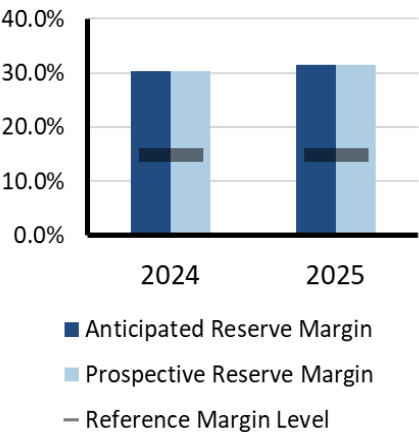
Highlights

- 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](#).

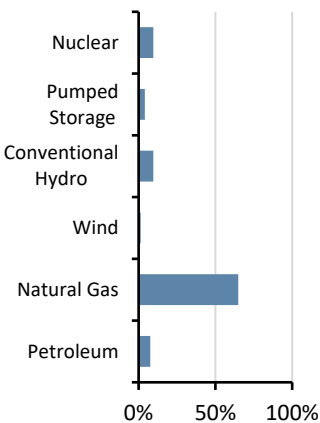
Risk Scenario Summary

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.

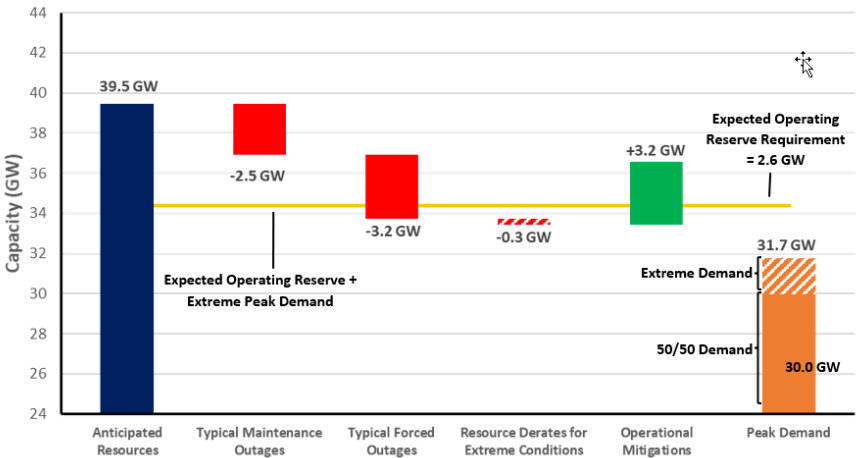
On-Peak Reserve Margin



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.

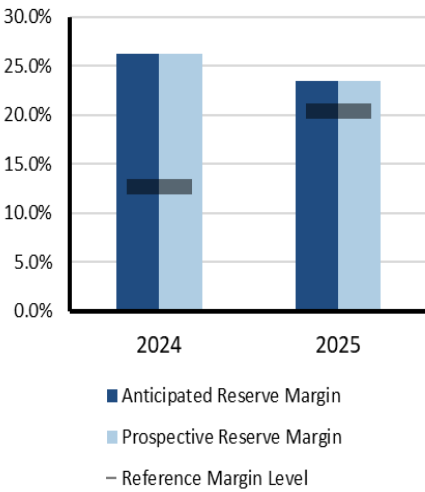
Highlights

- 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."

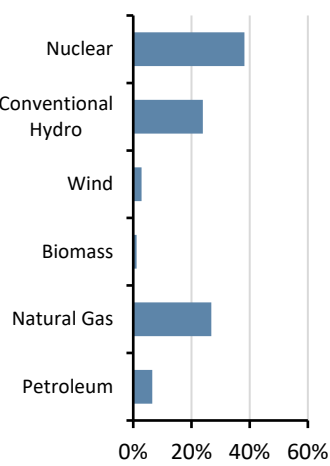
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

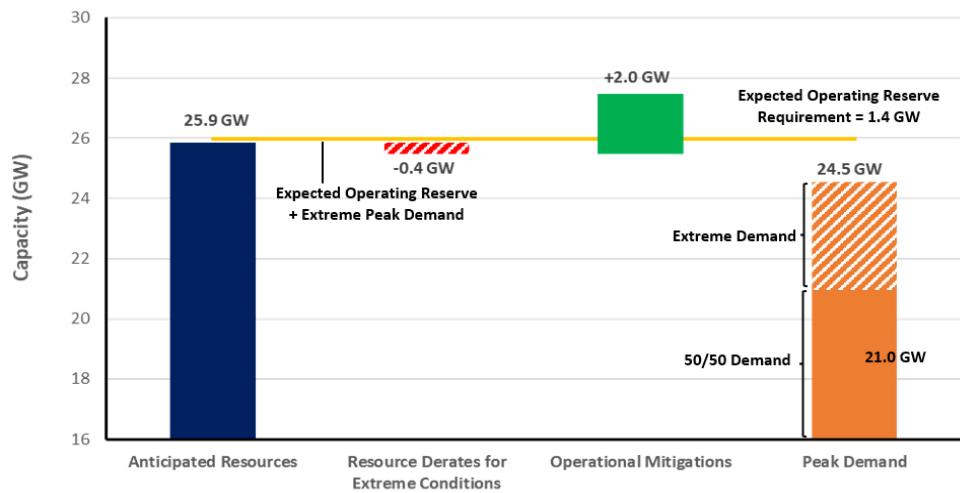
On-Peak Reserve Margin



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.

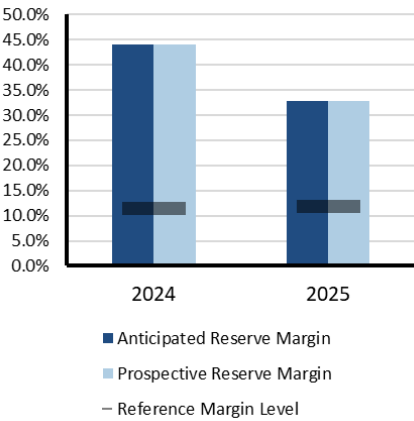
Highlights

- 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.

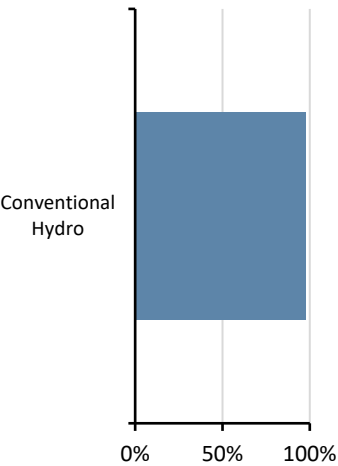
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

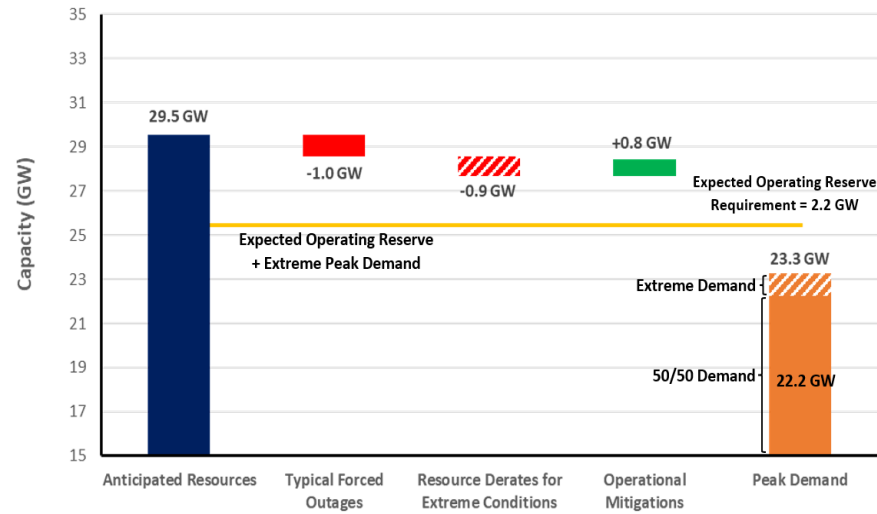
On-Peak Reserve Margin



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.



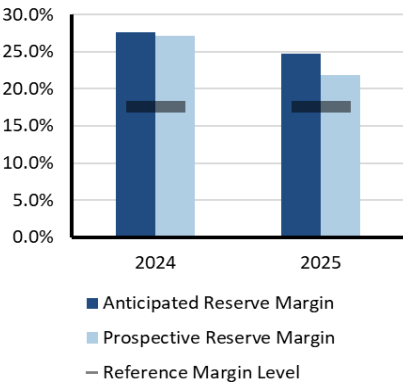
PJM

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.

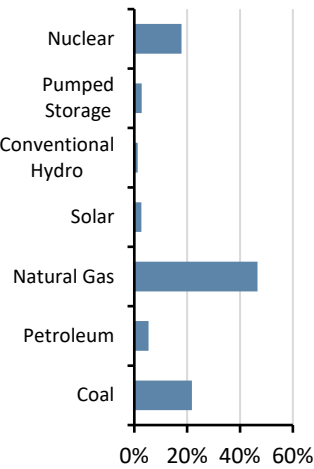
On-Peak Reserve Margin



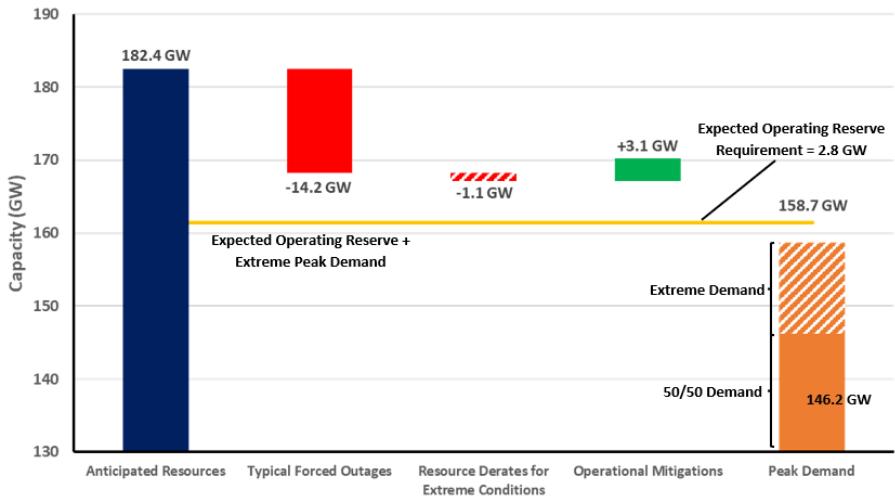
Risk Scenario Summary

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 (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



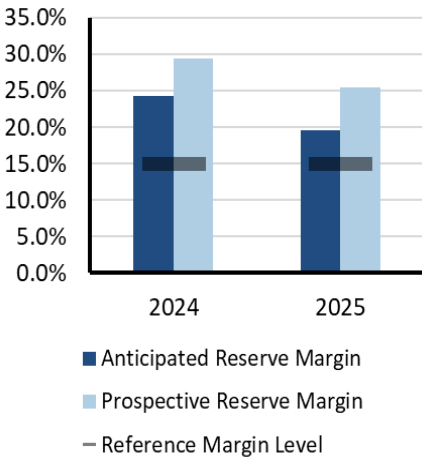
SERC-Central

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.

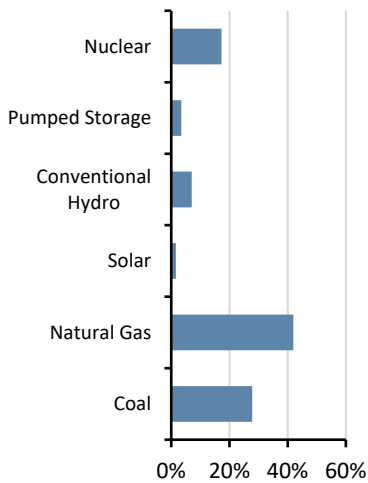
On-Peak Reserve Margin



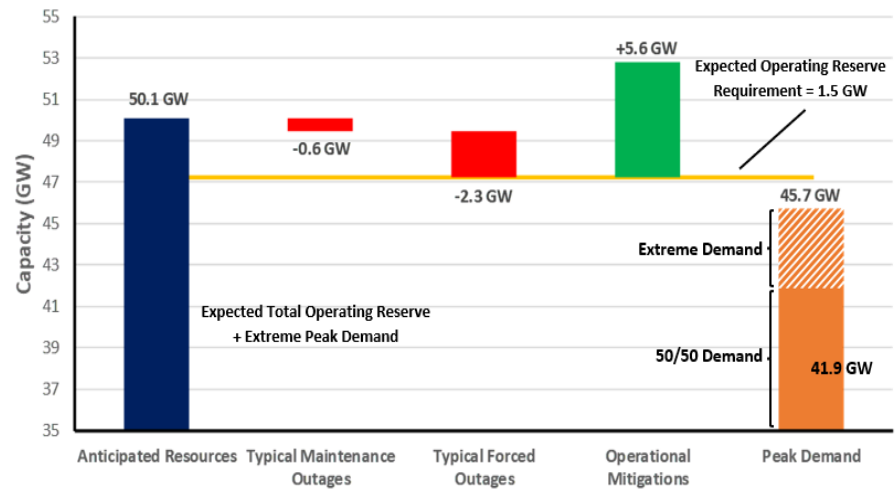
Risk Scenario Summary

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.

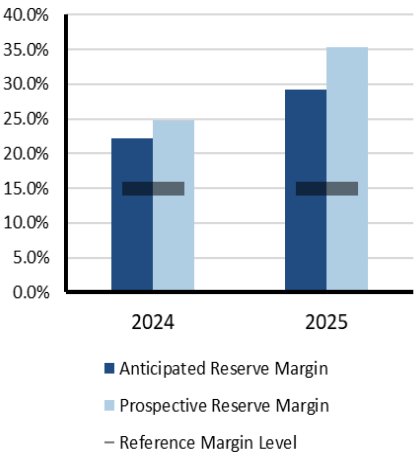
Highlights

- 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.

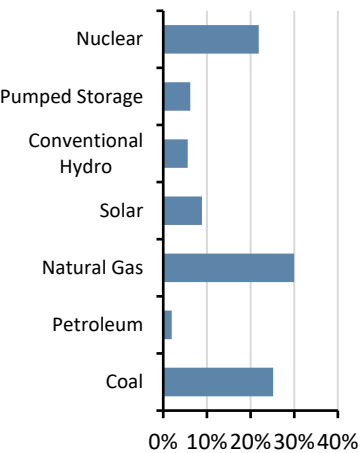
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

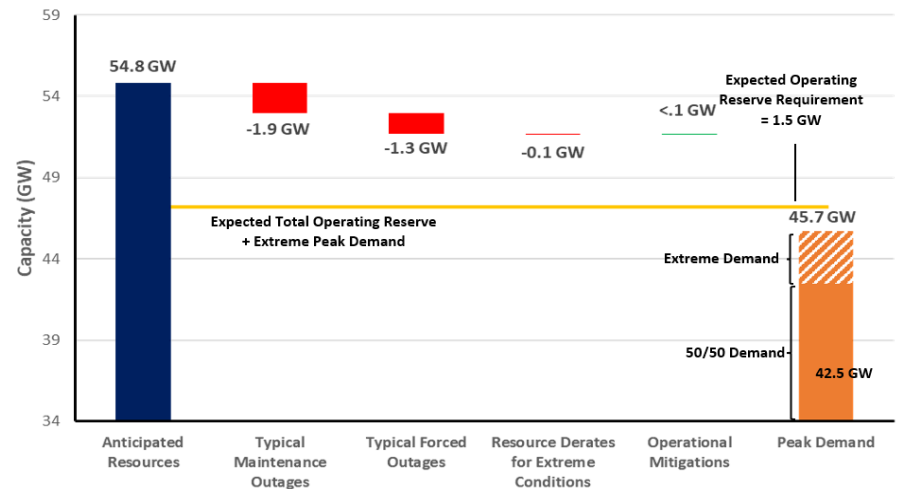
On-Peak Reserve Margin



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 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



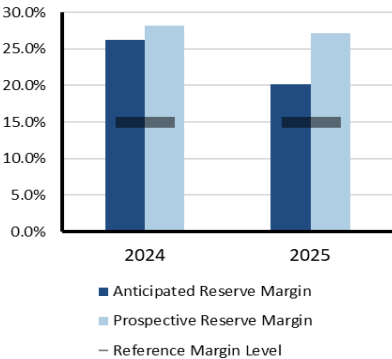
SERC-Florida Peninsula

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.

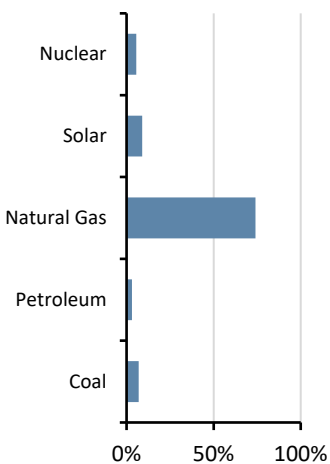
On-Peak Reserve Margin



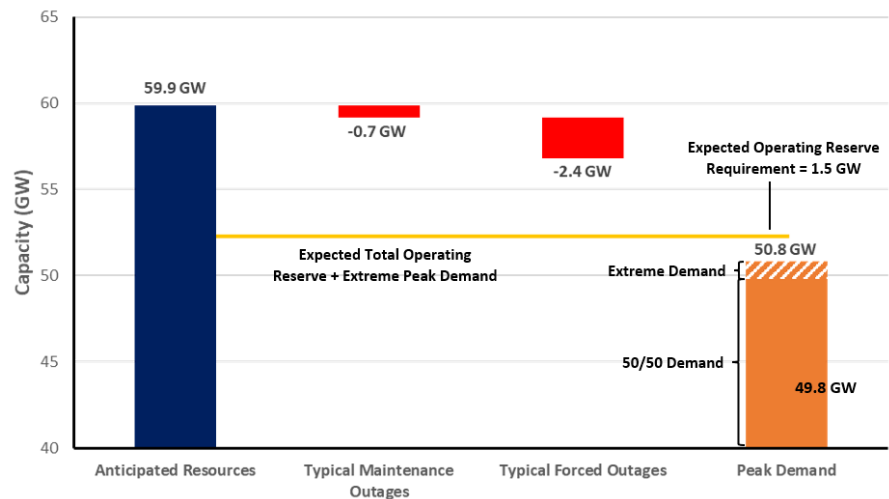
Risk Scenario Summary

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.

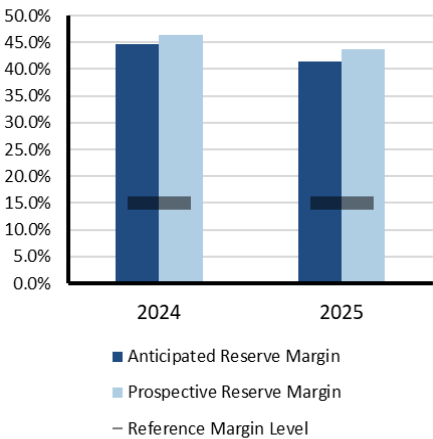
Highlights

- 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.

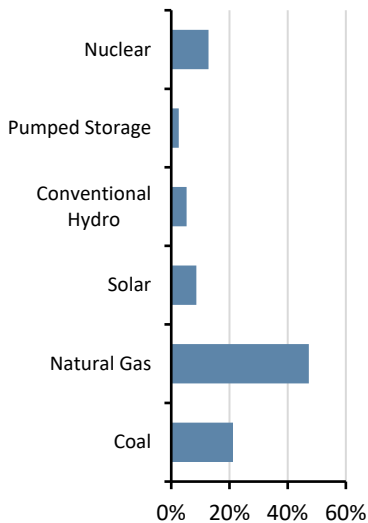
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

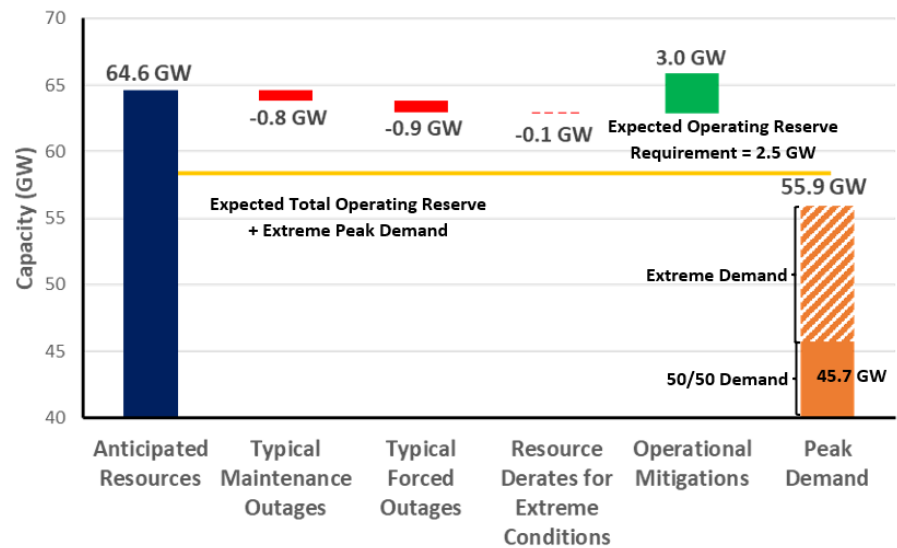
On-Peak Reserve Margin



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

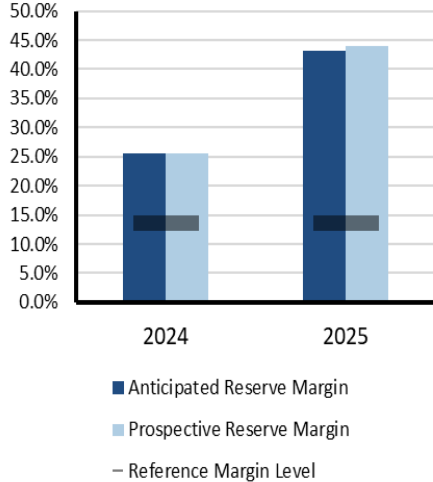
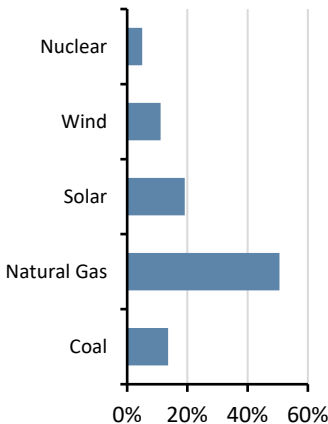
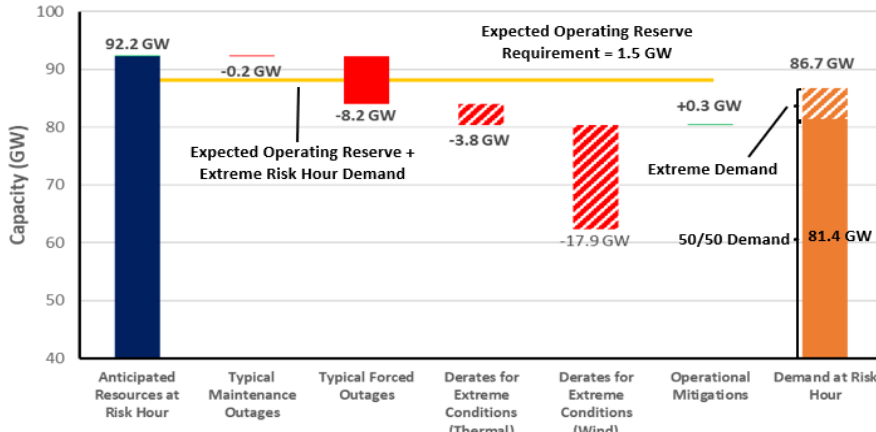
Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

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.	On-Peak Reserve Margin  <table><tr><th>Year</th><th>Anticipated Reserve Margin</th><th>Prospective Reserve Margin</th><th>Reference Margin Level</th></tr><tr><td>2024</td><td>~25.0%</td><td>~26.0%</td><td>15.0%</td></tr><tr><td>2025</td><td>~43.0%</td><td>~44.0%</td><td>15.0%</td></tr></table>	Year	Anticipated Reserve Margin	Prospective Reserve Margin	Reference Margin Level	2024	~25.0%	~26.0%	15.0%	2025	~43.0%	~44.0%	15.0%																					
Year	Anticipated Reserve Margin	Prospective Reserve Margin	Reference Margin Level																															
2024	~25.0%	~26.0%	15.0%																															
2025	~43.0%	~44.0%	15.0%																															
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 Fuel Mix  <table><tr><th>Fuel Source</th><th>Percentage</th></tr><tr><td>Nuclear</td><td>~5%</td></tr><tr><td>Wind</td><td>~10%</td></tr><tr><td>Solar</td><td>~15%</td></tr><tr><td>Natural Gas</td><td>~45%</td></tr><tr><td>Coal</td><td>~10%</td></tr></table>	Fuel Source	Percentage	Nuclear	~5%	Wind	~10%	Solar	~15%	Natural Gas	~45%	Coal	~10%	2025 Summer Risk Period Scenario (9:00 p.m. local time)  <table><tr><th>Category</th><th>Value (GW)</th></tr><tr><td>Anticipated Resources at Risk Hour</td><td>92.2</td></tr><tr><td>Typical Maintenance Outages</td><td>-0.2</td></tr><tr><td>Typical Forced Outages</td><td>-8.2</td></tr><tr><td>Derates for Extreme Conditions (Thermal)</td><td>-3.8</td></tr><tr><td>Derates for Extreme Conditions (Wind)</td><td>-17.9</td></tr><tr><td>50/50 Demand</td><td>81.4</td></tr><tr><td>Operational Mitigations</td><td>+0.3</td></tr><tr><td>Demand at Risk Hour</td><td>86.7</td></tr><tr><td>Expected Operating Reserve Requirement</td><td>88.2</td></tr></table>	Category	Value (GW)	Anticipated Resources at Risk Hour	92.2	Typical Maintenance Outages	-0.2	Typical Forced Outages	-8.2	Derates for Extreme Conditions (Thermal)	-3.8	Derates for Extreme Conditions (Wind)	-17.9	50/50 Demand	81.4	Operational Mitigations	+0.3	Demand at Risk Hour	86.7	Expected Operating Reserve Requirement	88.2	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
Fuel Source	Percentage																																	
Nuclear	~5%																																	
Wind	~10%																																	
Solar	~15%																																	
Natural Gas	~45%																																	
Coal	~10%																																	
Category	Value (GW)																																	
Anticipated Resources at Risk Hour	92.2																																	
Typical Maintenance Outages	-0.2																																	
Typical Forced Outages	-8.2																																	
Derates for Extreme Conditions (Thermal)	-3.8																																	
Derates for Extreme Conditions (Wind)	-17.9																																	
50/50 Demand	81.4																																	
Operational Mitigations	+0.3																																	
Demand at Risk Hour	86.7																																	
Expected Operating Reserve Requirement	88.2																																	



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.

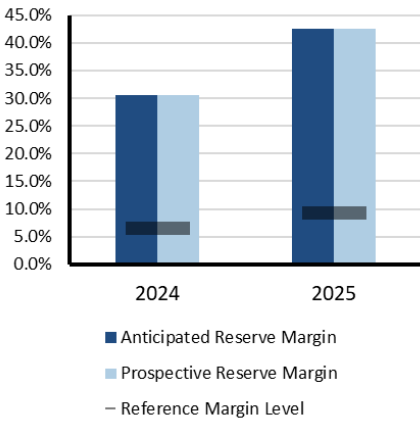
Highlights

- 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.

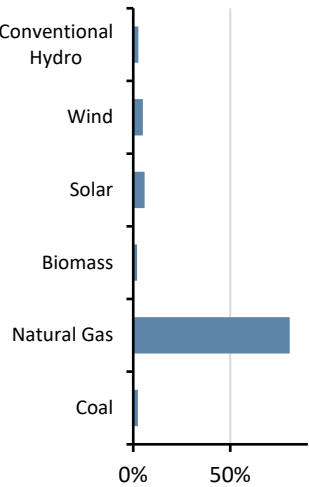
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

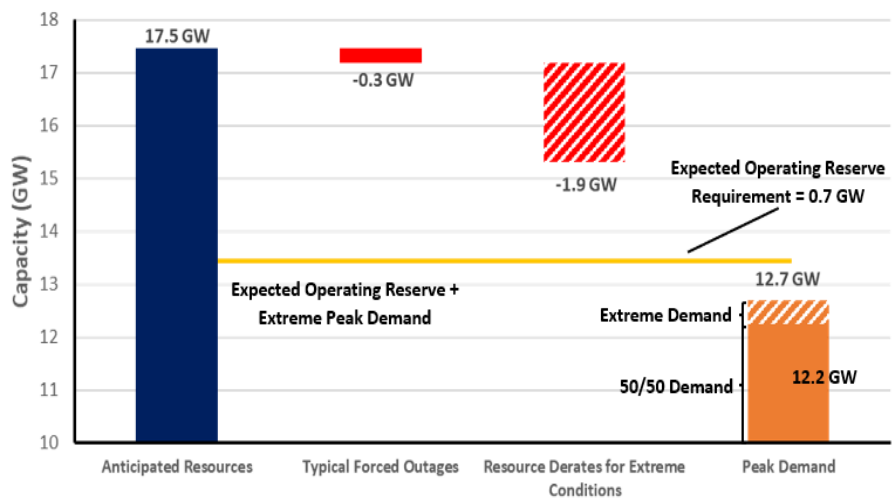
On-Peak Reserve Margin



On-Peak Fuel Mix

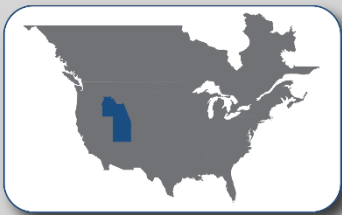


2025 Summer Risk Period Scenario



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

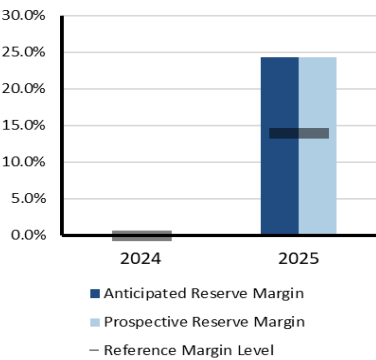
- Total internal expected demand has increased 8% and demand response has increased almost 28% for a net internal demand increase of 7.2%.
- Reserve margins are not anticipated to fall below the reference margin (14%) for the upcoming summer; an early July peak is expected at around 3:00 p.m.
- During 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

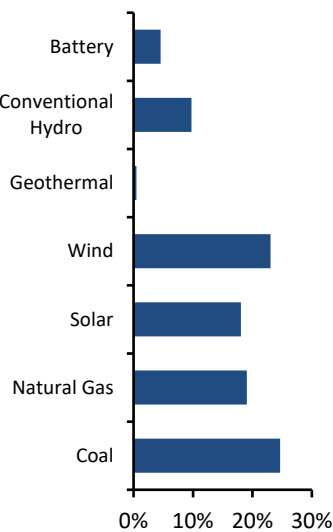
Expected resources meet operating reserve requirements under the assessed scenarios with imports.

On-Peak Reserve Margin

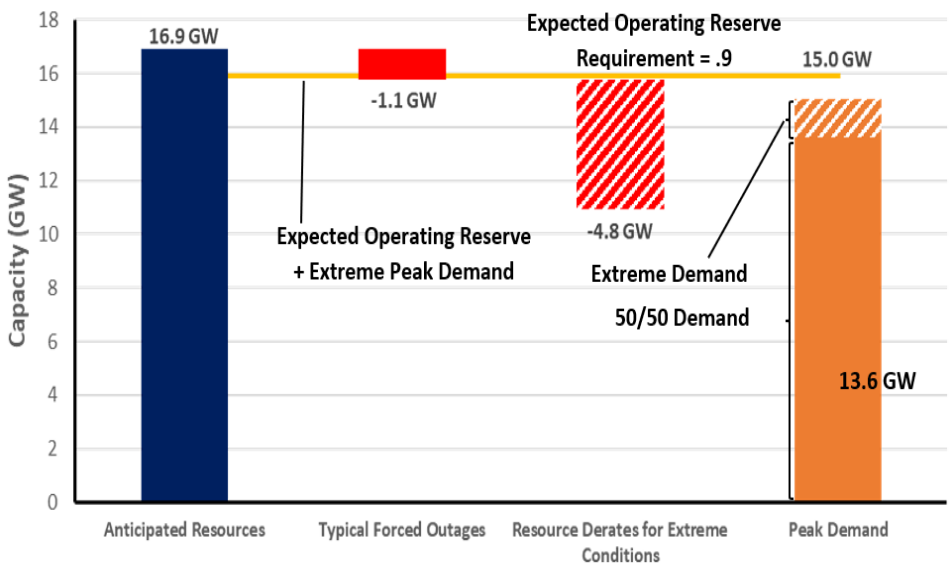
(Note: year comparison not available)



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.

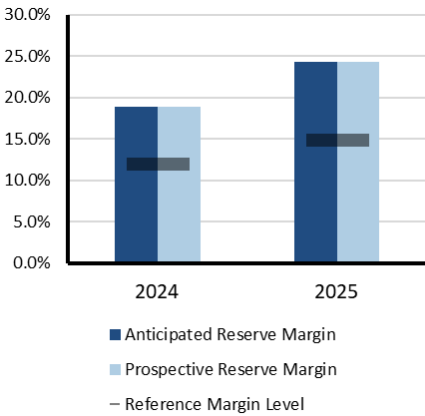
Highlights

- 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.

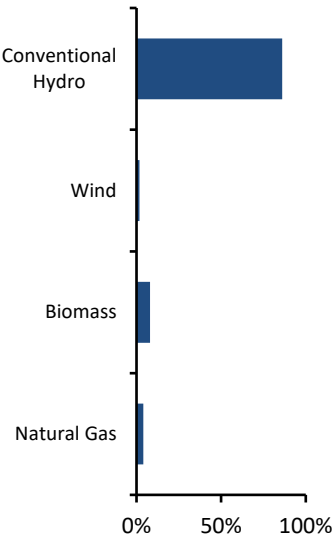
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

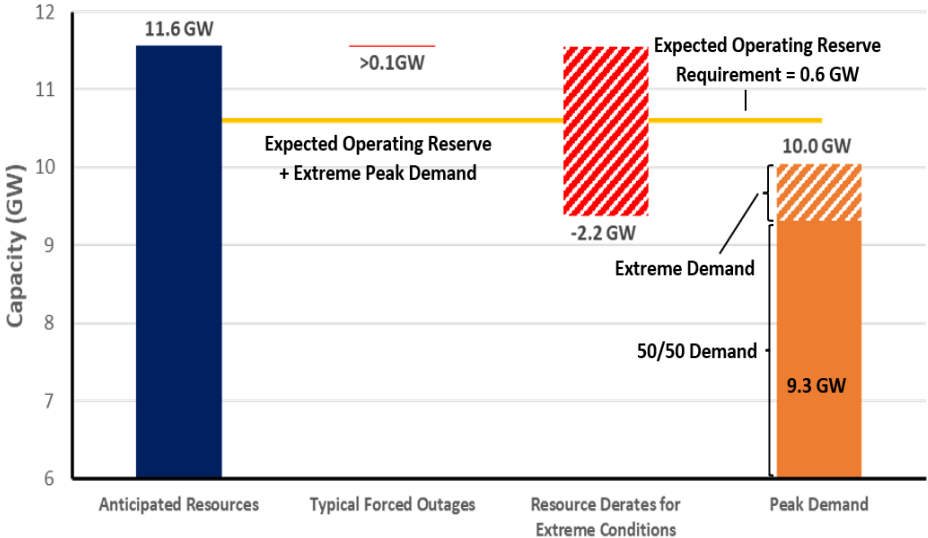
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



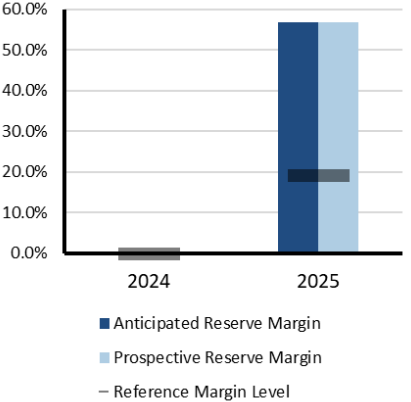
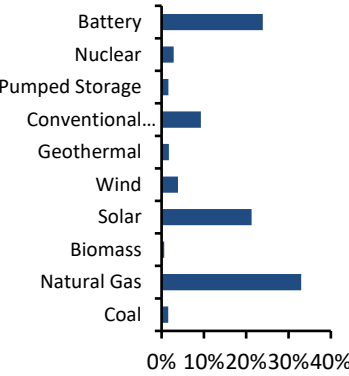
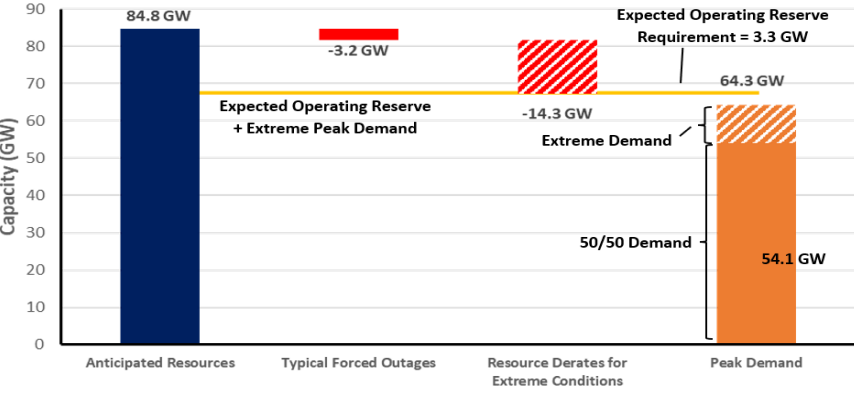
Scenario Description (See Data Concepts and Assumptions)

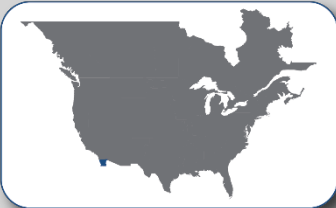
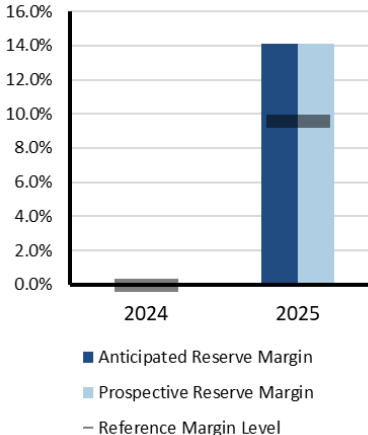
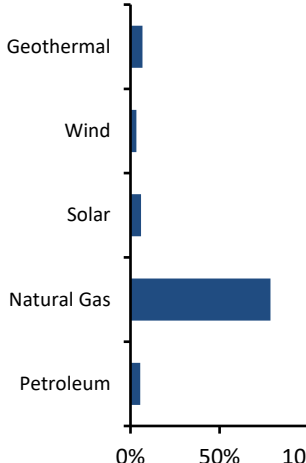
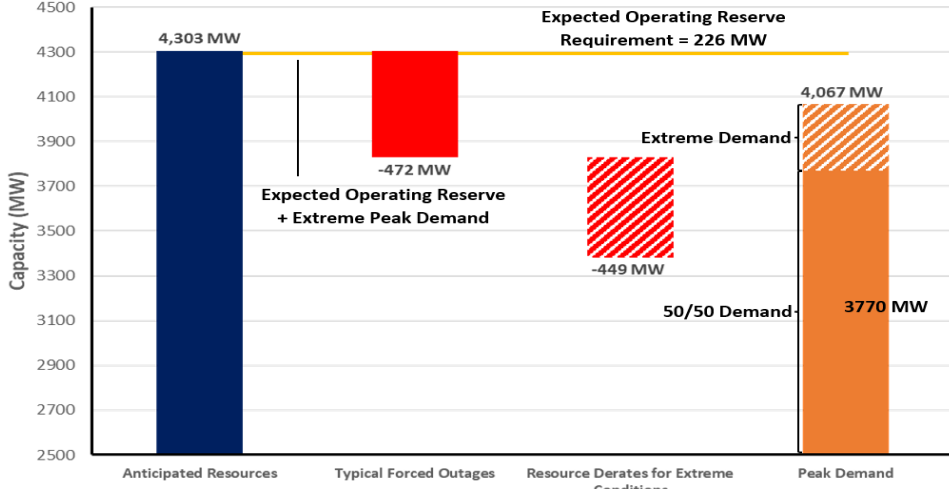
Risk Period: Highest risk for unserved energy at peak demand hour

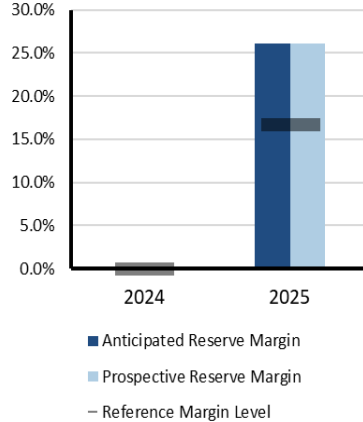
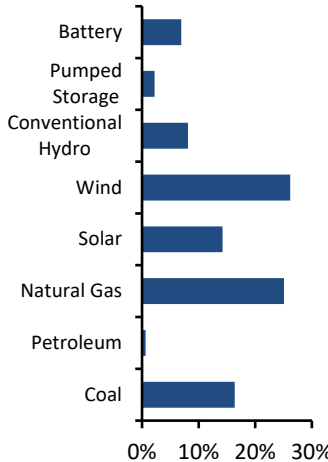
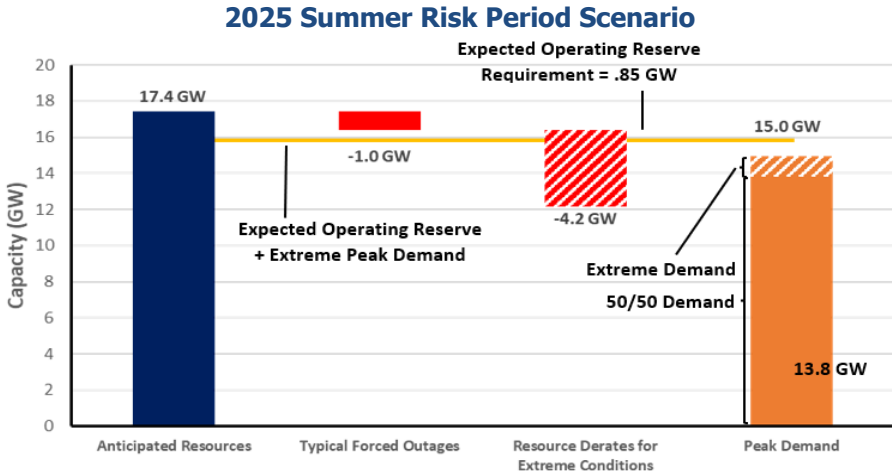
Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

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. <i>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.</i>
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.	On-Peak Reserve Margin (Note: year comparison not available) 
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 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. <i>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.</i>																												
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.		On-Peak Reserve Margin (Note: year comparison not available)  <table border="1"><thead><tr><th>Year</th><th>Anticipated Reserve Margin</th><th>Prospective Reserve Margin</th></tr></thead><tbody><tr><td>2024</td><td>~0.5%</td><td>~0.5%</td></tr><tr><td>2025</td><td>~14.1%</td><td>~14.0%</td></tr></tbody></table> ■ Anticipated Reserve Margin ■ Prospective Reserve Margin — Reference Margin Level		Year	Anticipated Reserve Margin	Prospective Reserve Margin	2024	~0.5%	~0.5%	2025	~14.1%	~14.0%																	
Year	Anticipated Reserve Margin	Prospective Reserve Margin																											
2024	~0.5%	~0.5%																											
2025	~14.1%	~14.0%																											
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 Fuel Mix  <table border="1"><thead><tr><th>Fuel Type</th><th>Percentage</th></tr></thead><tbody><tr><td>Geothermal</td><td>~5%</td></tr><tr><td>Wind</td><td>~5%</td></tr><tr><td>Solar</td><td>~5%</td></tr><tr><td>Natural Gas</td><td>~65%</td></tr><tr><td>Petroleum</td><td>~5%</td></tr></tbody></table>	Fuel Type	Percentage	Geothermal	~5%	Wind	~5%	Solar	~5%	Natural Gas	~65%	Petroleum	~5%	2025 Summer Risk Period Scenario  <table border="1"><thead><tr><th>Category</th><th>Value (MW)</th></tr></thead><tbody><tr><td>Anticipated Resources</td><td>4,303</td></tr><tr><td>Typical Forced Outages</td><td>-472</td></tr><tr><td>Resource Derates for Extreme Conditions</td><td>-449</td></tr><tr><td>50/50 Demand</td><td>3,770</td></tr><tr><td>Expected Operating Reserve Requirement</td><td>226</td></tr><tr><td>Peak Demand</td><td>4,067</td></tr></tbody></table>			Category	Value (MW)	Anticipated Resources	4,303	Typical Forced Outages	-472	Resource Derates for Extreme Conditions	-449	50/50 Demand	3,770	Expected Operating Reserve Requirement	226	Peak Demand	4,067
Fuel Type	Percentage																												
Geothermal	~5%																												
Wind	~5%																												
Solar	~5%																												
Natural Gas	~65%																												
Petroleum	~5%																												
Category	Value (MW)																												
Anticipated Resources	4,303																												
Typical Forced Outages	-472																												
Resource Derates for Extreme Conditions	-449																												
50/50 Demand	3,770																												
Expected Operating Reserve Requirement	226																												
Peak Demand	4,067																												
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. <i>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.</i>	
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.		On-Peak Reserve Margin  ■ Anticipated Reserve Margin ■ Prospective Reserve Margin — Reference Margin Level (Note: year comparison not available)
Risk Scenario Summary Expected resources meet operating reserve requirements under assessed scenarios with imports.		
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

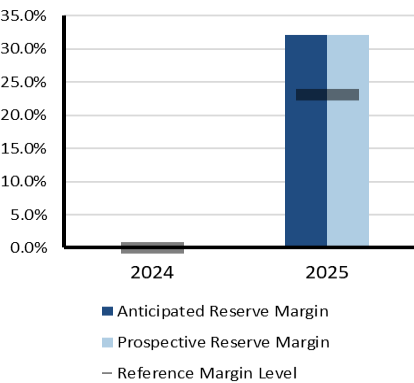
- The reserve margins (existing-certain 29% and anticipated and prospective 32%) are not anticipated to fall below the reference margin (23%) for the upcoming summer. An extreme summer peak load may be around 32,740 MW.
- Typical forced outages are forecast to be 771 MW, with derates for thermal under 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

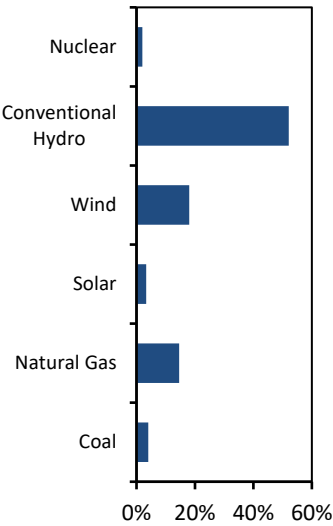
Expected resources meet operating reserve requirements under assessed scenarios with imports.

On-Peak Reserve Margin

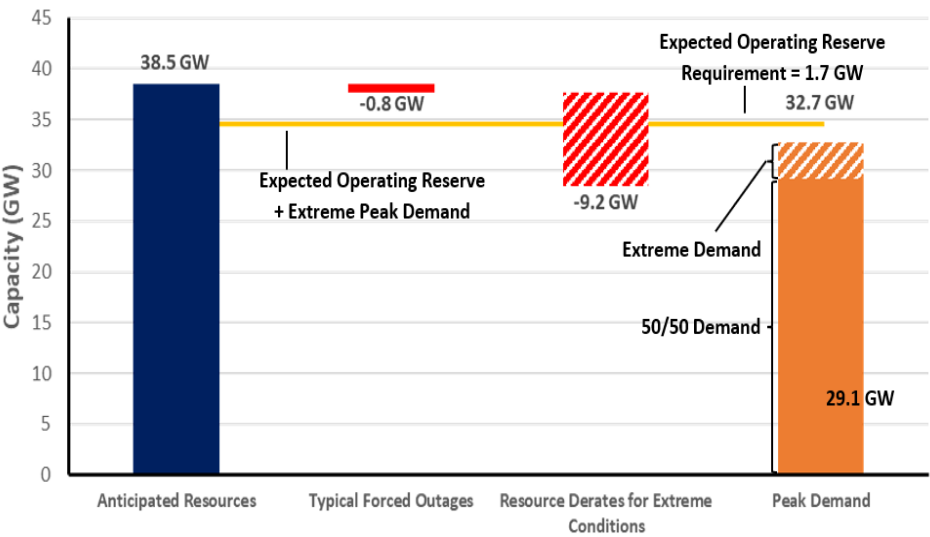
(Note: year comparison not available)



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



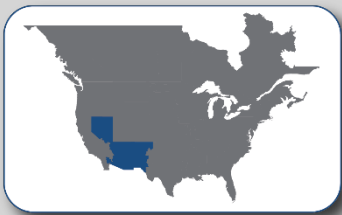
Scenario Description (See Data Concepts and Assumptions)

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

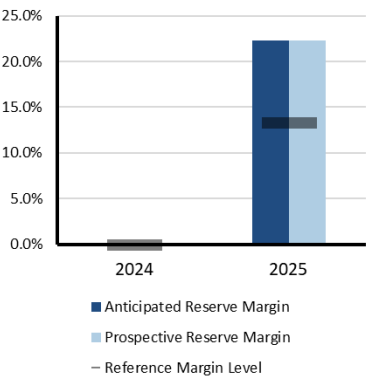
- Anticipated Reserve Margins for the summer are 22%, exceeding the Reference Margin Level for reliability calculated by WECC.
- WECC’s probabilistic analysis indicates that the area is not expected to encounter LOLH or EUE under a range of demand and resource conditions.
- The peak hour is expected 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

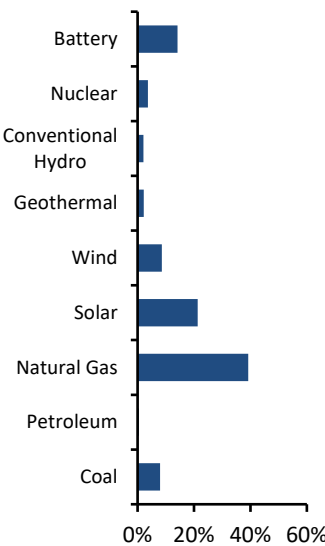
Expected resources meet operating reserve requirements under assessed scenarios with imports.

On-Peak Reserve Margin

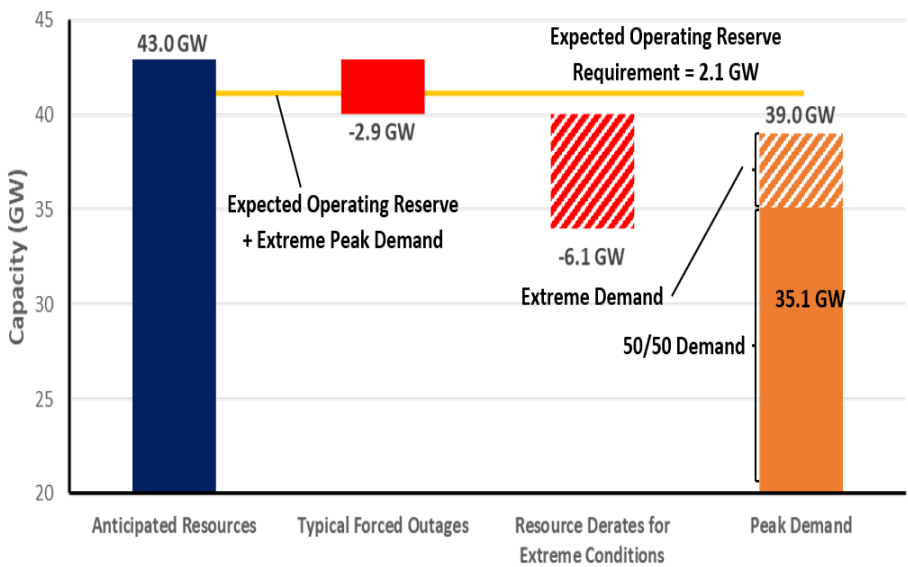
(Note: year comparison not available)



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 load¹² 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 coincident¹⁵ 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](#).

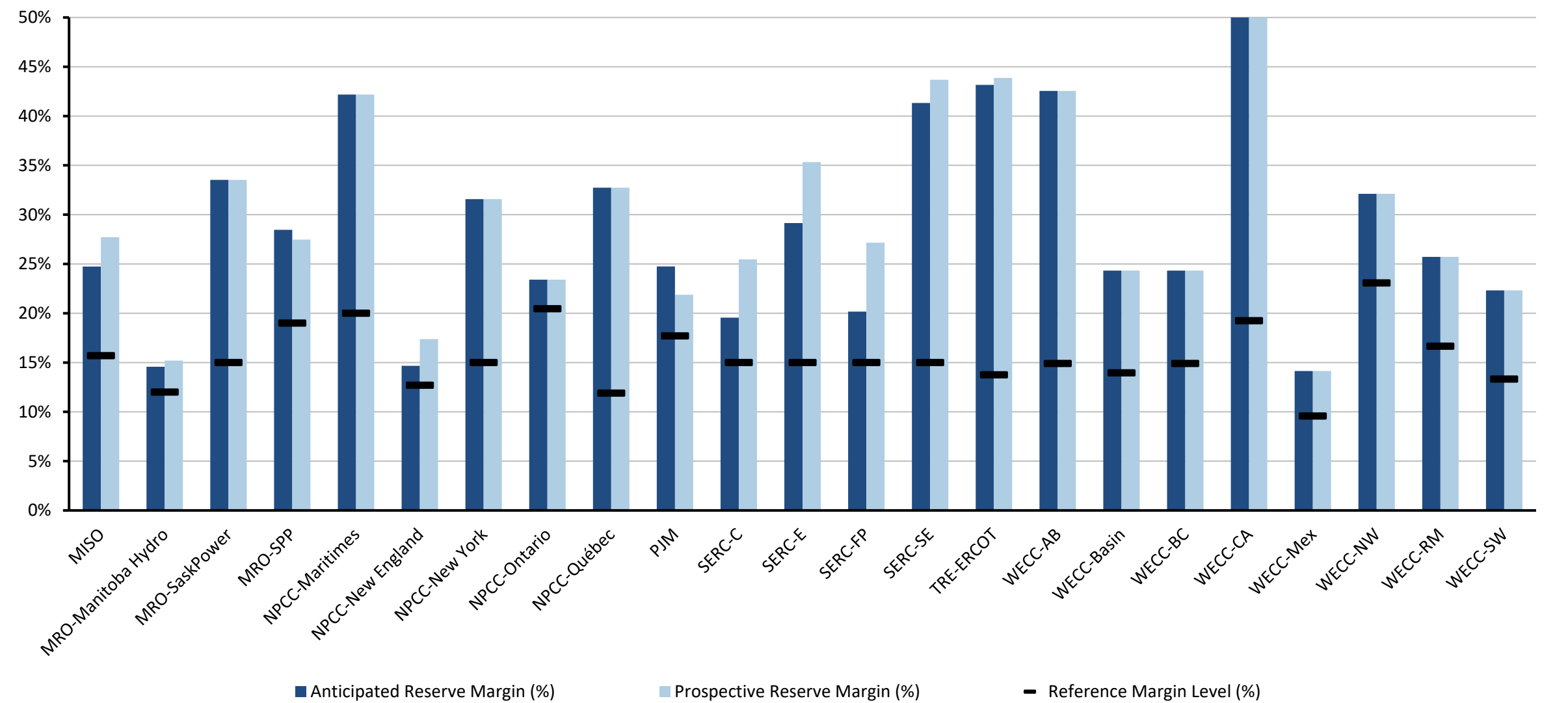


Figure 4: Summer 2025 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

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.

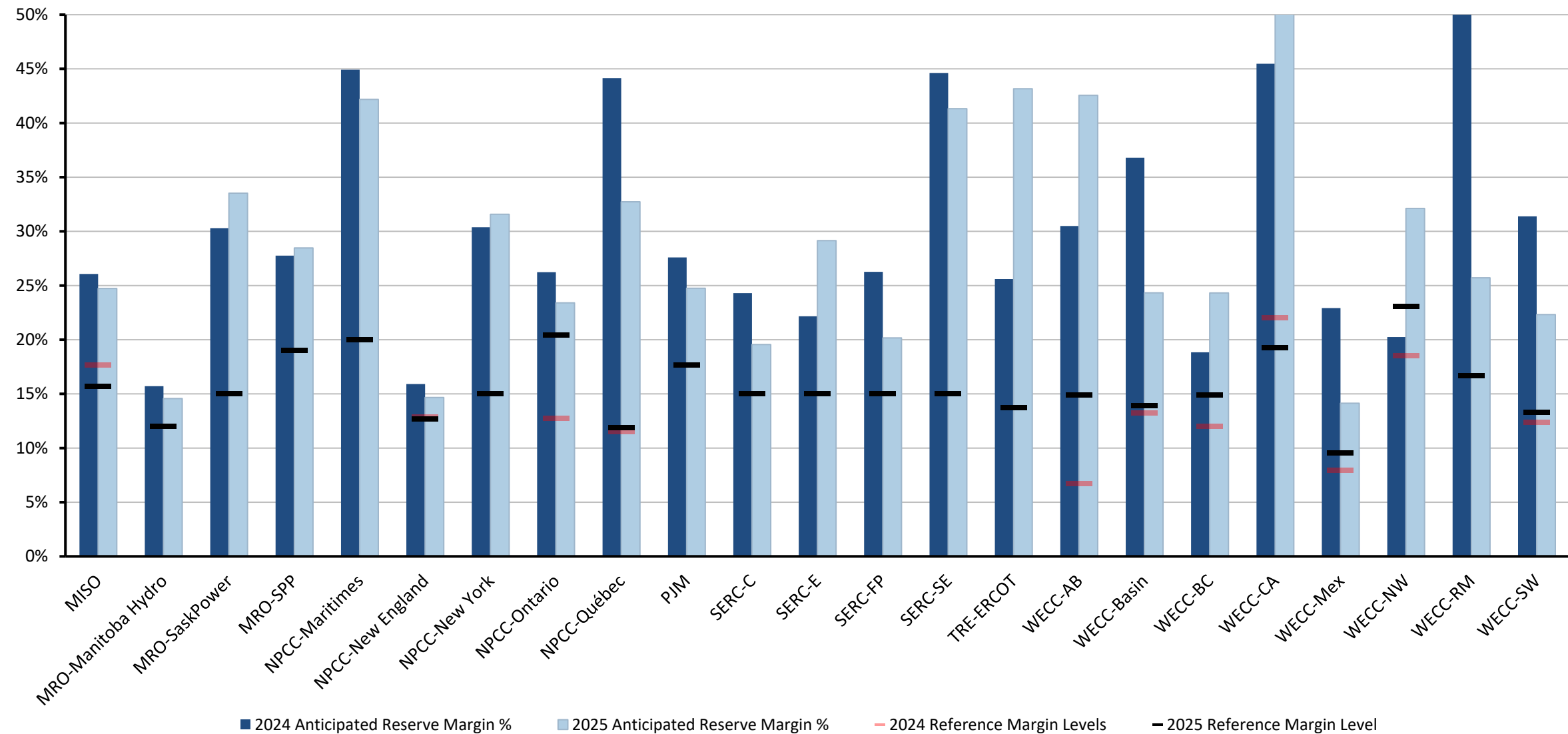


Figure 5: Summer 2024 and Summer 2025 Anticipated Reserve Margins Year-to-Year Change

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.

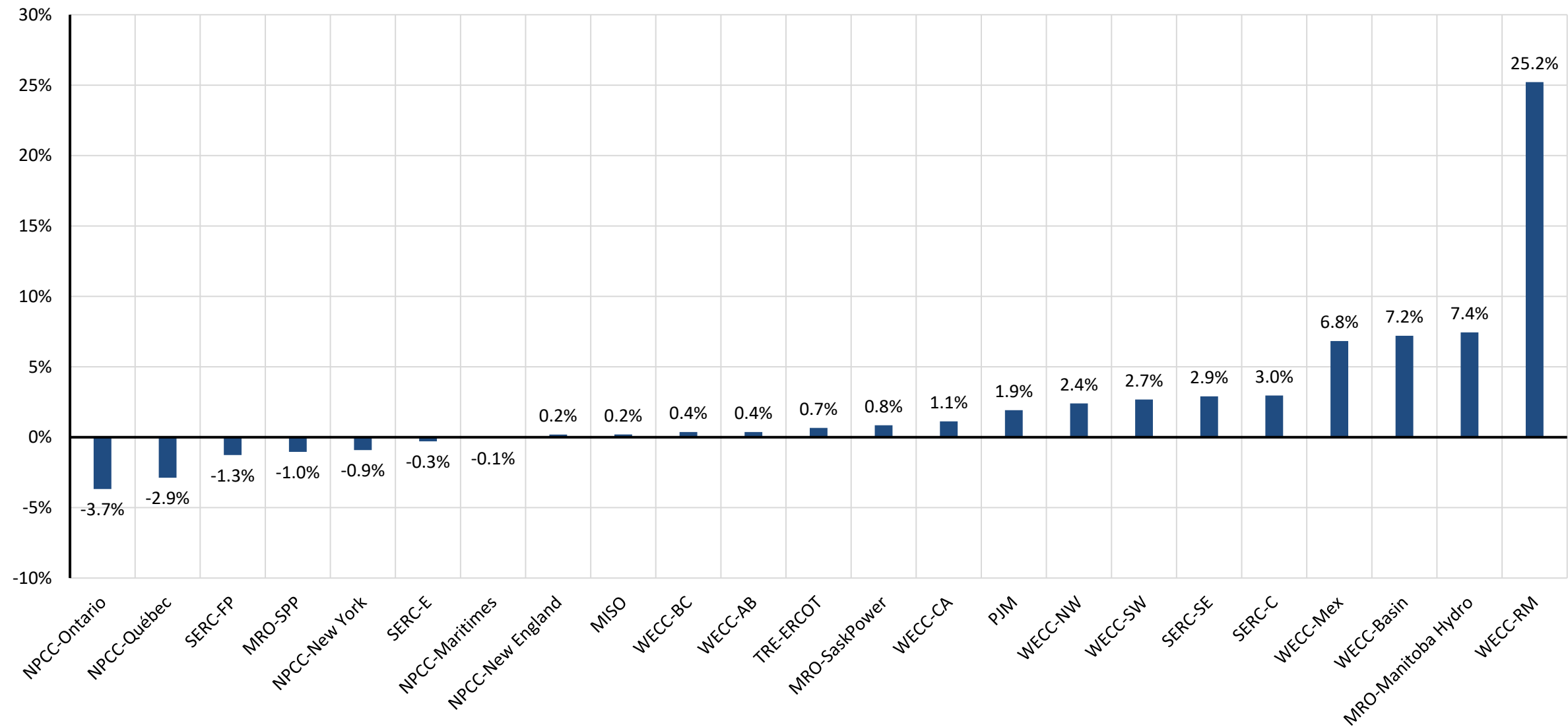


Figure 6: Changes in Net Internal Demand—Summer 2024 Forecast Compared to Summer 2025 Forecast

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-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-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-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 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-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-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

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-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

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

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

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

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-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-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-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-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

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

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 States¹⁸ 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 GW (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	4,565	5,599	5,858	4,981	4,412
		125.8					
MRO-Manitoba Hydro	3.6	3.1	50	48	0	0	290
		3.3					
MRO-SaskPower	3.7	3.5	170	208	22	6	0
		3.7					
MRO-SPP	54.3	55.3	10,869	5,876	442	486	6,046
		57.5					
NPCC-Maritimes	3.5	3.3	428	262	21	-	777
		3.6					
NPCC-New England	24.3	24.6	174	122	167	1,111	1,496
		26.5					
NPCC-New York	29	30.3	130	340	0	53	1,451
		32					
NPCC-Ontario	23.9	21.8	915	720	260	66	1,174
		23.7					
NPCC-Québec	23	22.9	2,270	-	0	-	10,500*
		24					
PJM	153.1	143.5	3,366	1,703	2,709	5,694	6,402
		156.9					
SERC-C	42.3	40.7	312	172	813	996	959
		43.9					
SERC-E	44	42.6	0	-	3,009	2,405	1,878
		44.7					
SERC-FP	52.4	50.5	0	-	5,376	5,643	
		53.6					
SERC-SE	44.9	44.4	0	-	3,507	7,217	1,007
		45.3					
TRE-ERCOT	85.5	81.3	6,286	9,070	17,566	17,797	3,622
		82.3					
WECC-AB	12.2	12.2	1,091	666	1,114	786	_**
		12.7					
WECC-BC	9.4	9.3	257	140	0.94	0	_**
		9.8					

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	1,633	1,124	10,112	13,147	921
		61.6					
WECC-NW	59.7	63	4,694	2,964	6,339	2,595	3,655
		69.7					
WECC-SW	30.8	26.4	1,179	542	3,357	1,294	2,042
		28.8					
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.							



[Home](#) > [Meet MISO](#) > [News Center](#) > [2025 - News Releases](#) > [MISO's Planning Resource Auction indicates sufficient resources](#)

MISO's Planning Resource Auction indicates sufficient resources

Improved pricing signal more accurately highlights reliability risk

For Immediate Release

April 28, 2025

Media Contact

[Brandon Morris](#)

CARMEL, Ind. — Today, MISO released the 2025 Planning Resource Auction (PRA) results indicating adequate resources are available to maintain reliability during the upcoming planning year (June 2025 – May 2026). While the 2025 auction prices reflect a tightening supply-demand balance during the summer months, there is sufficient capacity throughout the MISO footprint.

This is the first year MISO utilized a Reliability-Based Demand Curve (RBDC), which introduces a reliability-focused pricing structure that more accurately reflects the increasing value of accredited capacity as the system approaches minimum resource adequacy targets.

“MISO's market reforms continue to assist in providing pricing signals that improve market efficiency and enhance reliability across the footprint,” said Aubrey Johnson, MISO's vice president of system planning and competitive transmission. “We developed the RBDC through extensive collaboration with the Organization of MISO states, our stakeholders and our Independent Market Monitor to ensure this proactive approach helps meet the future needs of our evolving fleet.”

The seasonal Auction Clearing Prices are:

- Summer (June, July and August) \$666.50/MW-day
- Fall (September, October and November)
 - \$91.60/MW-day for the North/Central subregion
 - \$74.09/MW-day for the South subregion
- Winter (December, January and February) \$33.20/MW-day
- Spring (March, April and May) \$69.88/MW-day
- Annualized, the prices are \$217/MW-day for the North/Central region and \$212 for the South region.

The majority of MISO's Load Serving Entities (LSEs) either self-supply or secure the capacity they need before the auction. Those that enter the auction to procure capacity must pay the Auction Clearing Price and those holding excess capacity sell it at the same clearing price. The impact on consumer costs will vary and depends on factors such as the size of any capacity shortfall and the terms of wholesale power purchase agreements or state-regulated retail rates.

"This year's results underscore MISO's proactive Market Redefinition efforts to enhance resource availability as outlined in the Reliability Imperative." Johnson continues. "MISO, our states and our stakeholders continue to make progress responding to the resource adequacy challenges we face, and these results offer valuable insights to allow members to maximize their existing resources and plan for the ongoing energy transition."

MISO's Independent Market Monitor has reviewed and agreed with the offers and results of the 2025 PRA. MISO will host the [2025 Planning Resource Auction Results](#) meeting April, 29 at 10 a.m. ET.

##

MEDIA CONTACT:

[Brandon D. Morris](#)

About MISO

Midcontinent Independent System Operator (MISO) is an independent, not-for-profit organization that delivers safe, cost-effective electric power across 15 U.S. states and the Canadian province of Manitoba. 45 million people depend on MISO to generate and transmit the right amount of electricity every minute of every day. MISO is committed to reliable, nondiscriminatory operation of the bulk power transmission system and collaborating with all stakeholders to create cost-effective and innovative solutions for our changing industry. MISO operates one of the world's largest energy markets with more than \$40 billion in annual gross market energy transactions.

[News Release Link](#)



GET STARTED

[Login/Profile](#)

[Help Center](#)

[Contact Us](#)

[Code of Conduct](#)

[Compliance](#)

DISCOVER

[Calendar](#)

[Careers](#)

[MISO Matters - Blog](#)

[Notifications](#)

[Legal and Privacy](#)

POPULAR LINKS

[Market Displays](#)

[Operation Displays](#)

[Market Reports](#)

[Markets and Operations](#)

[Extranet](#)

A. Introduction

1. **Title:** **Planning Resource Adequacy Analysis, Assessment and Documentation**
2. **Number:** **BAL-502-RF-03**
3. **Purpose:** To establish common criteria, based on “one day in ten year” loss of Load expectation principles, for the analysis, assessment and documentation of Resource Adequacy for Load in the ReliabilityFirst Corporation (RF) region
4. **Applicability**
 - 4.1 Functional Entities
 - 4.1.1 Planning Coordinator
5. **Effective Date:**
 - 5.1 BAL-502-RF-03 shall become effective on the first day of the first calendar quarter that is after the date that this standard is approved by applicable regulatory authorities or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect.

B. Requirements and Measures

R1 The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning*]:

- 1.1 Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year¹ analyzed (per R1.2) being equal to 0.1. (This is comparable to a “one day in 10 year” criterion).
 - 1.1.1 The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the loss of Load probability.
 - 1.1.2 The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median² forecast peak Net Internal Demand (planning reserve margin).
- 1.2 Be performed or verified separately for each of the following planning years:

¹ The annual period over which the LOLE is measured, and the resulting resource requirements are established (June 1st through the following May 31st).

² The median forecast is expected to have a 50% probability of being too high and 50% probability of being too low (50:50).

- 1.2.1** Perform an analysis for Year One.
- 1.2.2** Perform an analysis or verification at a minimum for one year in the 2 through 5 year period and at a minimum one year in the 6 through 10 year period.
 - 1.2.2.1** If the analysis is verified, the verification must be supported by current or past studies for the same planning year.
- 1.3** Include the following subject matter and documentation of its use:
 - 1.3.1** Load forecast characteristics:
 - 1.3.1.1 Median (50:50) forecast peak Load.
 - 1.3.1.2 Load forecast uncertainty (reflects variability in the Load forecast due to weather and regional economic forecasts).
 - 1.3.1.3 Load diversity.
 - 1.3.1.4 Seasonal Load variations.
 - 1.3.1.5 Daily demand modeling assumptions (firm, interruptible).
 - 1.3.1.6 Contractual arrangements concerning curtailable/Interruptible Demand.
 - 1.3.2** Resource characteristics:
 - 1.3.2.1 Historic resource performance and any projected changes
 - 1.3.2.2 Seasonal resource ratings
 - 1.3.2.3 Modeling assumptions of firm capacity purchases from and sales to entities outside the Planning Coordinator area.
 - 1.3.2.4 Resource planned outage schedules, deratings, and retirements.
 - 1.3.2.5 Modeling assumptions of intermittent and energy limited resource such as wind and cogeneration.
 - 1.3.2.6 Criteria for including planned resource additions in the analysis
 - 1.3.3** Transmission limitations that prevent the delivery of generation reserves
 - 1.3.3.1** Criteria for including planned Transmission Facility additions in the analysis

- 1.3.4 Assistance from other interconnected systems including multi-area assessment considering Transmission limitations into the study area.
 - 1.4 Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included:
 - 1.4.1 Availability and deliverability of fuel.
 - 1.4.2 Common mode outages that affect resource availability
 - 1.4.3 Environmental or regulatory restrictions of resource availability.
 - 1.4.4 Any other demand (Load) response programs not included in R1.3.1.
 - 1.4.5 Sensitivity to resource outage rates.
 - 1.4.6 Impacts of extreme weather/drought conditions that affect unit availability.
 - 1.4.7 Modeling assumptions for emergency operation procedures used to make reserves available.
 - 1.4.8 Market resources not committed to serving Load (uncommitted resources) within the Planning Coordinator area.
 - 1.5 Consider Transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included
 - 1.6 Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis
 - 1.7 Document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis
- M1** Each Planning Coordinator shall possess the documentation that a valid Resource Adequacy analysis was performed or verified in accordance with R1
- R2** The Planning Coordinator shall annually document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis [*Violation Risk Factor: Lower*] [*Time Horizon: Long-term Planning*].
- 2.1 This documentation shall cover each of the years in Year One through ten.

- 2.2 This documentation shall include the Planning Reserve margin calculated per requirement R1.1 for each of the three years in the analysis.
- 2.3 The documentation as specified per requirement R2.1 and R2.2 shall be publicly posted no later than 30 calendar days prior to the beginning of Year One.

M2 Each Planning Coordinator shall possess the documentation of its projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis on an annual basis in accordance with R2.

R3 The Planning Coordinator shall identify any gaps between the needed amount of planning reserves defined in Requirement R1, Part 1.1 and the projected planning reserves documented in Requirement R2 [*Violation Risk Factor: Lower*] [*Time Horizon: Long-term Planning*].

M3 Each Planning Coordinator shall possess the documentation identifying any gaps between the needed amounts of planning reserves and projected planning reserves in accordance with R3.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Applicable Entity shall keep data or evidence to show compliance with Requirements R1 through R3, and Measures M1 through M3 from the most current and prior two years.

If an Applicable Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit
Self-Certification
Spot Checking

Compliance Investigation
Self-Reporting
Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	VIOLATION SEVERITY LEVEL			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Medium	The Planning Coordinator Resource Adequacy analysis failed to consider 1 or 2 of the Resource availability characteristics subcomponents under Requirement R1, Part 1.4 and documentation of how and why they were included in the analysis or why they were not included OR The Planning Coordinator Resource Adequacy analysis failed to consider Transmission maintenance outage schedules and document how and why they were included in the analysis or why they were not included per Requirement R1, Part 1.5	The Planning Coordinator Resource Adequacy analysis failed to express the planning reserve margin developed from Requirement R1, Part 1.1 as a percentage of the net Median forecast peak Load per Requirement R1, Part 1.1.2 OR The Planning Coordinator Resource Adequacy analysis failed to include 1 of the Load forecast Characteristics subcomponents under Requirement R1, Part 1.3.1 and documentation of its use OR	The Planning Coordinator Resource Adequacy analysis failed to be performed or verified separately for individual years of Year One through Year Ten per Requirement R1, Part 1.2 OR The Planning Coordinator failed to perform an analysis or verification for one year in the 2 through 5 year period or one year in the 6 through 10 year period or both per Requirement R1, Part 1.2.2 OR The Planning Coordinator Resource Adequacy analysis failed to include 2 or	The Planning Coordinator failed to perform and document a Resource Adequacy analysis annually per R1. OR The Planning Coordinator Resource Adequacy analysis failed to calculate a Planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year analyzed for each planning period being equal to 0.1 per Requirement R1, Part 1.1 OR

				The Planning Coordinator Resource Adequacy analysis failed to include 1 of the Resource Characteristics subcomponents under Requirement R1, Part 1.3.2 and documentation of its use OR The Planning Coordinator Resource Adequacy analysis failed to document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis per Requirement R1, Part 1.7	more of the Load forecast Characteristics subcomponents under Requirement R1, Part 1.3.1 and documentation of their use OR The Planning Coordinator Resource Adequacy analysis failed to include 2 or more of the Resource Characteristics subcomponents under Requirement R1, Part 1.3.2 and documentation of their use OR The Planning Coordinator Resource Adequacy analysis failed to include Transmission limitations and documentation of its use	The Planning Coordinator failed to perform an analysis for Year One per Requirement R1, Part 1.2.1
--	--	--	--	--	--	---

					per Requirement R1, Part 1.3.3 OR The Planning Coordinator Resource Adequacy analysis failed to include assistance from other interconnected systems and documentation of its use per Requirement R1, Part 1.3.4 OR The Planning Coordinator Resource Adequacy analysis failed to consider 3 or more Resource availability characteristics subcomponents under Requirement R1, Part 1.4 and documentation of how and why they were included in the analysis or why they were not included	
--	--	--	--	--	--	--

					OR The Planning Coordinator Resource Adequacy analysis failed to document that capacity resources are appropriately accounted for in its Resource Adequacy analysis per Requirement R1, Part 1.6	
R2	Long-term Planning	Lower	The Planning Coordinator failed to publicly post the documents as specified per requirement Requirement R2, Part 2.1 and Requirement R2, Part 2.2 later than 30 calendar days prior to the beginning of Year One per Requirement R2, Part 2.3	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for one of the years in the 2 through 10 year period per Requirement R2, Part 2.1. OR The Planning Coordinator failed to document the Planning	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for year 1 of the 10 year period per Requirement R2, Part 2.1. OR The Planning Coordinator failed to document the projected Load and resource	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis per Requirement R2, Part 2.

				Reserve margin calculated per requirement R1.1 for each of the three years in the analysis per Requirement R2, Part 2.2.	capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for two or more of the years in the 2 through 10 year period per Requirement R2, Part 2.1.	
R3	Long-term Planning	Lower	None	None	None	The Planning Coordinator failed to identify any gaps between the needed amount of planning reserves and the projected planning reserves, per R3

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

None

Version History

Version	Date	Action	Change Tracking
BAL-502-RFC-02	12/04/08	ReliabilityFirst Board Approved	
BAL-502-RFC-02	08/05/09	NERC BoT Approved	
BAL-502-RFC-02	03/17/11	FERC Approved	
BAL-502-RFC-03	06/01/17	ReliabilityFirst Board Approved	
BAL-502-RF-03	08/10/17	NERC BOT Approved	
BAL-502-RF-03	10/16/17	FERC Approved	

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

Consumers Energy Company	)	
	)	
	)	Docket No. EL25-90-000
v.	)	
	)	
Midcontinent Independent System Operator, Inc.	)	
	)	

**ANSWER OF THE
MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC.**

The Midcontinent Independent System Operator, Inc. (“MISO” or “Respondent”) submits¹ this Answer to the Complaint of Consumers Energy Company (“Consumers Energy” or “Complainant”). Consumers Energy filed the Complaint in response to an order issued by the U.S. Secretary of Energy pursuant to Federal Power Act (“FPA”) section 202(c) and section 201(b) of the Department of Energy Authorization Act.² The DOE Order determined “that an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes[.]”³ To address that emergency, the DOE Order directs MISO and Consumers Energy to take all measures necessary to ensure that the J.H. Campbell coal-fired power plant in West Olive, MI (“Campbell Plant”) is available to operate.⁴ Consumers Energy’s Complaint requests that MISO’s Open Access Transmission, Energy and Operating Reserve Markets Tariff (“Tariff”) be revised to permit

¹ See Rules 206 and 213 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission (“FERC” or “Commission”), 18 C.F.R. § 385.206(f) (2025); 18 C.F.R. § 385.213 (2025).

² U.S. Department of Energy, Order No. 202-25-3, at 2 (May 23, 2025) (“DOE Order”).

³ DOE Order at 1.

⁴ DOE Order at 2.

recovery of costs incurred incident to the DOE Order, and provides draft Tariff language for the Commission's review.

As recognized by the Order, MISO's Planning Resource Auction for the 2025-2026 Planning Year demonstrated sufficient capacity for all zones within the MISO Region.⁵ While MISO does not intend to contest, within the context of this docket, the characterization within the Order that an emergency exists "due to a shortage of electric energy . . . [or] a shortage of facilities," it is important to recognize existing processes have cleared sufficient electric generating capacity across MISO for the periods of time covered by the Order. The clearing of sufficient capacity to meet anticipated demand across the MISO Region for the 2025-2026 Planning Year reflects the diligent efforts of MISO's members, Market Participants, Relevant Electric Retail Regulatory Authorities (RERRA) and the Federal Energy Regulatory Commission (FERC) to establish policies and processes that address both immediate, and future capacity requirements. MISO continues to work with these parties in the context of anticipated growing demand for electricity, planned electric generating facility retirements, and an evolving mix of new electric generating resources to refine processes that address the challenges ahead. MISO is confident that these collaborative efforts do not require further intervention and will help ensure the region continues to procure sufficient capacity to meet demand.

MISO acknowledges that the DOE Order directs Consumers Energy "to file with the Federal Energy Regulatory Commission Tariff revisions or waivers necessary to effectuate this order."⁶ MISO also acknowledges that the DOE Order provides that "[r]ate recovery is available pursuant to 16 U.S.C. § 824a(c)."⁷ MISO supports the addition of a cost recovery schedule to the

⁵ Department of Energy Order No. 202-25-3 (May 23, 2025) at p. 2.

⁶ DOE Order at 3.

⁷ DOE Order at 3.

Tariff, subject to the reservations noted below, and believes that a Commission finding that such a mechanism be incorporated in the Tariff would further compliance with the DOE Order by both Consumers and MISO.

I. BACKGROUND

The Secretary of Energy issued the DOE Order on May 23, 2025.⁸ The DOE Order identifies an “emergency situation” in the MISO region and states that MISO “faces potential tight reserve margins during the summer 2025 period, particularly during periods of high demand or low generation resource output.”⁹ The DOE Order notes that the Campbell Plant is scheduled to cease operations on May 31, 2025,” and concludes that the Campbell Plant’s retirement “would further decrease available dispatchable generation within MISO’s service territory[.]”¹⁰ The DOE Order states that, although MISO and Consumers Energy incorporated the Campbell Plant’s planned retirement into their supply forecasts and acquired a 1,200 MW natural gas plant in Covert, MI, the North American Electric Reliability Corporation’s (“NERC”) analysis still anticipates an “elevated risk of operating reserve shortfalls.”¹¹ The DOE Order concludes that “additional dispatch of the Campbell Plant is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c).”¹²

The DOE Order directs MISO and Consumers Energy to “take all measures necessary to ensure that the Campbell Plant is available to operate.”¹³ MISO is “directed to take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers” and “to provide the [DOE] with information concerning the measures it has taken and is planning to take to ensure

⁸ DOE Order at 3.

⁹ DOE Order at 1.

¹⁰ DOE Order at 1.

¹¹ DOE Order at 2.

¹² DOE Order at 3.

¹³ DOE Order at 2.

the operational availability and economic dispatch of the Campbell Plant consistent with the public interest.”¹⁴ MISO notes that it is working closely with Consumers and the other owners of the Campbell Plant to ensure the plant is available to operate in compliance with the DOE Order.

The DOE Order states that, to “[t]he extent to which MISO’s current Tariff provisions are inapposite to effectuate the dispatch and operation of the units for the reasons specified herein, the relevant governmental authorities are directed to take such action and make accommodations as may be necessary to do so.”¹⁵ The Order further provides that “Consumers [Energy] is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers necessary to effectuate this order.”¹⁶ The DOE Order states that “[r]ate recovery is available pursuant to 16 U.S.C. § 824a(c).”¹⁷

II. ANSWER

A. The Tariff Does Not Currently Include a Mechanism to Allow Cost Recovery Pursuant to the DOE Order.

Consumers Energy observes that there is no MISO Tariff provision that would permit Consumers Energy’s costs of complying with the DOE Order to be allocated to Load Serving Entities (“LSEs”) in MISO’s northern and central zones, and that MISO does not have the unilateral authority to offer Consumers Energy a section 202(c) rate agreement.¹⁸ MISO agrees. MISO acknowledges that its Tariff does not currently include a mechanism to allow the cost recovery contemplated by the DOE Order. As discussed below, MISO does not oppose the addition of a cost recovery schedule to its Tariff that would allow Consumers Energy to recover its costs as contemplated by the DOE Order.

¹⁴ DOE Order at 2-3.

¹⁵ DOE Order at 3.

¹⁶ DOE Order at 3.

¹⁷ DOE Order at 3.

¹⁸ Complaint at 18.

B. MISO Does Not Oppose the Addition of a Cost Recovery Schedule for the Recovery of These Costs, and Will File a Cost Recovery Schedule to the Extent Directed by the Commission.

MISO does not oppose the addition of a cost recovery schedule that would permit Consumers Energy to recover the costs incurred as a result of its efforts to comply the DOE Order. MISO will file such a schedule if directed by the Commission.

C. MISO Reserves Its Right to Modify or Otherwise Change the Cost Recovery Allocation Formula, As Necessary, to Account for Existing Tariff Requirements or Changes.

MISO reserves the right to modify, adjust, or otherwise change the cost recovery allocation formula proposed by Consumers, should it be necessary, to account for existing Tariff requirements and to include other clarifications as may be appropriate.

III. ADMISSIONS AND DENIALS; AFFIRMATIVE DEFENSES

MISO denies all allegations in the Complaint not specifically and expressly admitted herein.¹⁹

IV. COMMUNICATIONS

All notices and communications with respect to this proceeding should be directed to:

Timothy Caister*
Vice President, Legal & Federal
Regulatory Affairs
Michael Kessler
Managing Assistant General Counsel
Midcontinent Independent
System Operator, Inc.
720 City Center Drive
Carmel, IN 46032
Telephone: (317) 249-5400
tcaister@misoenergy.org
mkessler@misoenergy.org

James C. Holsclaw*
Taylor M. Carpenter
Calfee, Halter & Griswold, LLP
3900 Salesforce Tower
111 Monument Circle
Indianapolis, IN 46204
317-308-4266
jholsclaw@calfee.com
tcarpenter@calfee.com

*Persons designated to receive official service

¹⁹ 18 C.F.R. § 385.213(c)(2)(i)-(ii).

V. CONCLUSION

WHEREFORE, MISO respectfully requests that the Commission accept this answer.

Respectfully submitted,

/s/ Timothy Caister

Timothy Caister

Vice President, Legal & Federal

Regulatory Affairs

Michael Kessler

Managing Assistant General Counsel

Midcontinent Independent

System Operator, Inc.

720 City Center Drive

Carmel, IN 46032

Telephone: (317) 249-5400

tcaister@misoenergy.org

mkessler@misoenergy.org

James C. Holsclaw

Taylor M. Carpenter

Calfee, Halter & Griswold, LLP

3900 Salesforce Tower

111 Monument Circle

Indianapolis, IN 46204

Telephone: (317) 308-4266

jholsclaw@calfee.com

tcarpenter@calfee.com

*Counsel for Midcontinent Independent System
Operator, Inc.*

CERTIFICATE OF SERVICE

I hereby certify that I have on this day e-served a copy of this document upon all parties listed on the official service list compiled by the Secretary in the above-captioned proceeding, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated this 19th day of June, 2025 in Carmel, Indiana.

/s/ Adriana Rodriguez
Adriana Rodriguez
Midcontinent Independent
System Operator, Inc.

Dated: June 19, 2025

MISO IMM Blasts NERC Long-term Assessment, Says RTO in Good RA Spot

By Amanda Durish Cook

MINNEAPOLIS — MISO Independent Market Monitor David Patton called NERC's Long-Term Reliability Assessment inaccurate for labeling MISO a high-risk area and said he believes MISO is in a good reliability position.

"We find that it is completely inaccurate. MISO should not be colored in red," Patton said at a June 10 Markets Committee meeting of the MISO Board of Directors.

Patton faulted NERC for apparently conflating installed capacity with unforced capacity in the assessment's totals. He said NERC tallied unforced capacity values for MISO when calculating a margin that it ultimately compared to an installed capacity requirement. He said the blunder lowered the footprint's capacity sums on paper by more than 10 GW.

"I don't frankly understand how they did this," Patton said. "They basically presented an apples and oranges assessment."

NERC's Long-Term Reliability Assessment predicted MISO could be confronted with capacity shortfalls in 2025. It assumed the RTO would have 132.2 GW in generating capacity, or 124.4 GW after factoring in all retirement announcements. (See [NERC Warns Challenges 'Mounting' in Coming Decade](#).)

Ahead of summer, MISO reported it has 143.1 GW in offered capacity available to it to meet a likely 123-GW annual peak. (See [MISO Prepping for Likely 123-GW Summer 2025 Peak](#).) Altogether, the RTO has 203 GW of installed capacity.

Patton said NERC's lapse is influencing national policy, evidenced by the Department of Energy's directive to keep Consumers Energy's 1.4-GW J.H. Campbell coal plant in Michigan operating over the summer. (See [Consumers Energy Seeking Compensation for Keeping Campbell Open](#).) He said NERC's projection could bleed into other rule changes.

"That sort of initiative can lead to FERC ordering market changes that are unnecessary," Patton said.

Patton also said MISO overstated load

predictions used in NERC's assessment by submitting non-coincident peak forecasts instead of coincident peaks, raising its load requirements and lowering the calculated capacity margin.

Patton said of the four RTO markets he monitors, "I would say MISO is most reliable of the four."

"It seems like a combination of errors that seems correctable here, but there isn't a path for correction," MISO Director Barbara Krumsiek said.

Patton said he hopes NERC will rectify its methods that inform the long-term assessment by the next December report. He said he has reached out to NERC and committed to working with the regulatory authority on its approach.

Michelle Bloodworth, CEO of coal lobby organization America's Power, questioned whether it was appropriate for the MISO Market Monitor to question a "credible institution" such as NERC. She said she believed MISO's "elevated risk" status under the assessment was apt.

Bloodworth praised the DOE's actions to keep J.H. Campbell available for a little while longer. She noted that Cleco's 568-MW Big Cajun II Unit 1 shuttered March 31 due to a settlement decree; she said having the coal plant online at the time might have helped matters during MISO's load shedding orders in the New Orleans area on May 25. (See [NOLA City Council Puts Entergy, MISO in Hot Seat over Outages](#).)

At the same meeting, MISO said it likely will manage higher-than-normal temperatures paired with drought over the summer.

"If you're dry and have a pervasive heatwave going on, it can compound challenges in the operating room," MISO Executive Director of Market Operations JT Smith said.

Smith said a doubled-in-size solar fleet also likely will test MISO's ramp and regulation capabilities in its ancillary market. He said MISO operators could be managing unavailable resources and higher-than-expected load throughout summer.

Why This Matters

MISO IMM David Patton panned the RTO's precarious standing in NERC's Long-Term Reliability Assessment. He waved away resource adequacy concerns and said NERC botched a margin-to-capacity requirement comparison, apparently mixing up unforced capacity and installed capacity.

As part of a five-year update, Vice President of Operations Renuka Chatterjee said MISO finds itself in the most "dynamic and demanding" operating environment it ever has. She cited steeper evening ramps and mounting long-duration outages, forecasting challenges and stability risks.

MISO entered summer June 1 with a \$666.50/MW-day capacity price, signifying the premium the RTO has put on new capacity. (See [MISO Summer Capacity Prices Shoot to \\$666.50 in 2025/26 Auction](#).)

Carrie Milton, of the IMM staff, said if generation operators had held off on powering down about 1.6 GW until September, it would have lowered capacity prices to \$472/MW-day in the summer.

But Milton said the Campbell plant is not factored into MISO's clearing prices and isn't necessary for reliability during the season. She said MISO's auction already returned a better than one-day-in-10-years standard without the large coal plant.

"We are more than adequate," Patton said. He repeated that he has "no material concerns" over MISO's resource adequacy for the upcoming summer.

Patton said factoring in imports and typical planned and forced outages, MISO has a comfortable, 12.2% reserve margin. ■

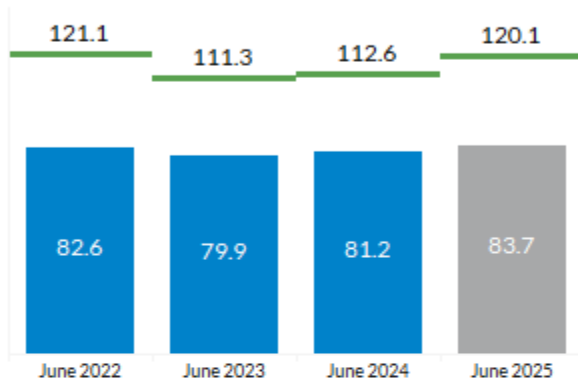


MISO Monthly Operations Report

June 2025

Reliability, markets and operational functions performed as expected in June

AVERAGE & PEAK LOAD (GW)



SYSTEM-WIDE LOAD PEAK



120 GW

June 23, Hour Ending (HE) 16

SOLAR PEAK



13.1 GW

Jun 22, 2025, HE 11

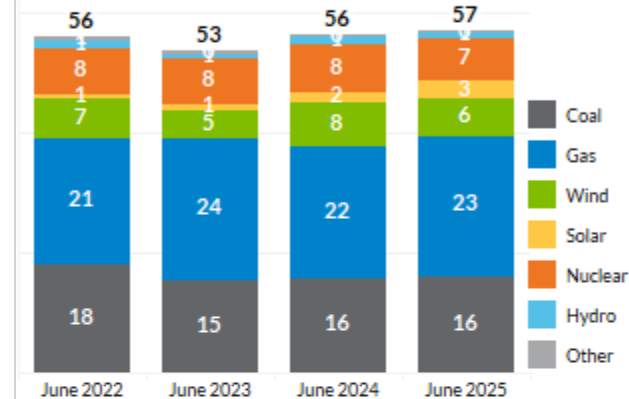
WIND PEAK



21.5 GW

Jun 20, 2025, HE 23

ENERGY FUEL MIX (TWh)



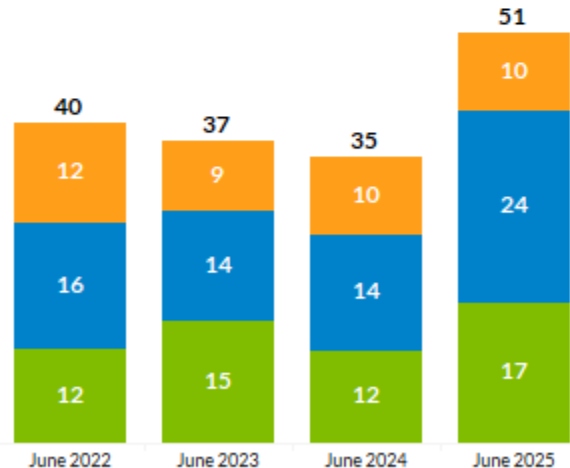
REAL-TIME LMP (\$/MWh)



AVERAGE FUEL PRICE (\$/MMBtu)



AVERAGE DAILY GENERATION OUTAGE (GW)



KEY OPERATING DECLARATIONS

JUNE 2025

1	2	3	4	5	6	7
8	9	10	11	12	13	14
15	16	17	18	19	20	21
22	23	24	25	26	27	28
29	30					

06/06-06/08 South: Conservative Operations
06/12 South: Severe Weather Alert
06/18 Central: Severe Weather Alert
06/20-06/21 North: Severe Weather Alert
06/21-06/24 N/C: Hot Weather Alert
06/23 N/C: Max Gen Event - Step 1b
06/24 N/C: Max Gen Warning
06/21-06/27 System: Conservative Operations

- All-Time Solar Peak: 13.5 GW on May 31, 2025, HE 13
- All-Time Wind Peak: 25.7 GW on Jan 12, 2024, HE 19
- All-Time Load Peak: 127.1 GW on Jul 20, 2011, HE17

- Awareness and Weather
- Alerts and Warnings
- Reliability Actions and Events

Dashboard

Metric	Chart	June 2025	May '25	Apr '25	Mar '25	Metric	Chart	June 2025	May '25	Apr '25	Mar '25
Market Efficiency Metric	D	▼	●	●	●	Unit Commitment Efficiency	H	●	●	●	●
Percentage Price Deviation	A	■	■	■	●	Day Ahead Wind Generation Forecast Error	K	●	●	●	●
Monthly Average Gross Virtual Profitability	B	●	●	●	●	Day-Ahead Solar Generation Forecast Error	T	●	●	●	●
FTR Funding	C	●	●	●	●	Tie Line Error	L	●	●	●	●
RSG per MWh to Energy Price	E	●	●	●	●	Control Performance – BAAL	M	●	●	●	●
Day Ahead Mid-Term Load Forecast	F	●	■	▼	▼	Control Performance – CPS1 and CPS1 12-month rolling	N	●	●	●	●
Short-Term Load Forecast	G	●	●	■	●	ARS Deployment	P	●	●	●	●
Real-Time Obligation fulfilled by Day-Ahead Supply at the Peak Hour	I	●	●	●	●						
System Impact Study Performance	Q	▼	●	▼	▼	Settlement Disputes	S	●	●	●	●

● Expected ■ Concern/Monitor ▼ Review

Three metrics fell outside of the expected range for this month

Metric	Expected Criteria	Actual	Status	Comments
Percentage Price Deviation	Absolute DA-RT price difference divided by DA LMP ≤28.6%	32.8%	Monitor	Periods of congestion, especially on June 23 and June 24, and Real-Time ancillary service product scarcity pricing throughout the month resulted in some price divergence between the Day-Ahead and Real-Time markets.
Market Efficiency Metric	≥ 95%	90.5%	Review	Excess Congestion Fund (ECF) performance for the month of June was largely impacted by the effects of the notable heat days (6/21-6/24) as well as outlier constraints. The high impact ECF constraints were driven by large Joint Operating Agreement payments to SPP, outages, Real-Time congestion management actions, and congestion forecast.
System Impact Study Performance	Studies completed in less than 60 days ≥85%	Completed studies were done in more than 60 days	Review	Resource constraints impacted study completion timing.

Appendix

MISO has worked collaboratively with stakeholders to review and implement the following changes on the Monthly Operations Report

Removed

- Price Duration Curve – Peak Hours
- Price Duration Curve – Off-Peak Hours
- MISO Hubs RT Price Duration – Peak Hours
- MISO Hubs RT Price Duration – Off-Peak Hours
- Load Duration Curve
- Solar Energy and Daily Peak

Modified

- Add hours to Manual Redispatch/Cap summary on the Reliability slide
- Provided regional breakdown for Real-Time Congestion Dollars
- Consolidated load and temperature information

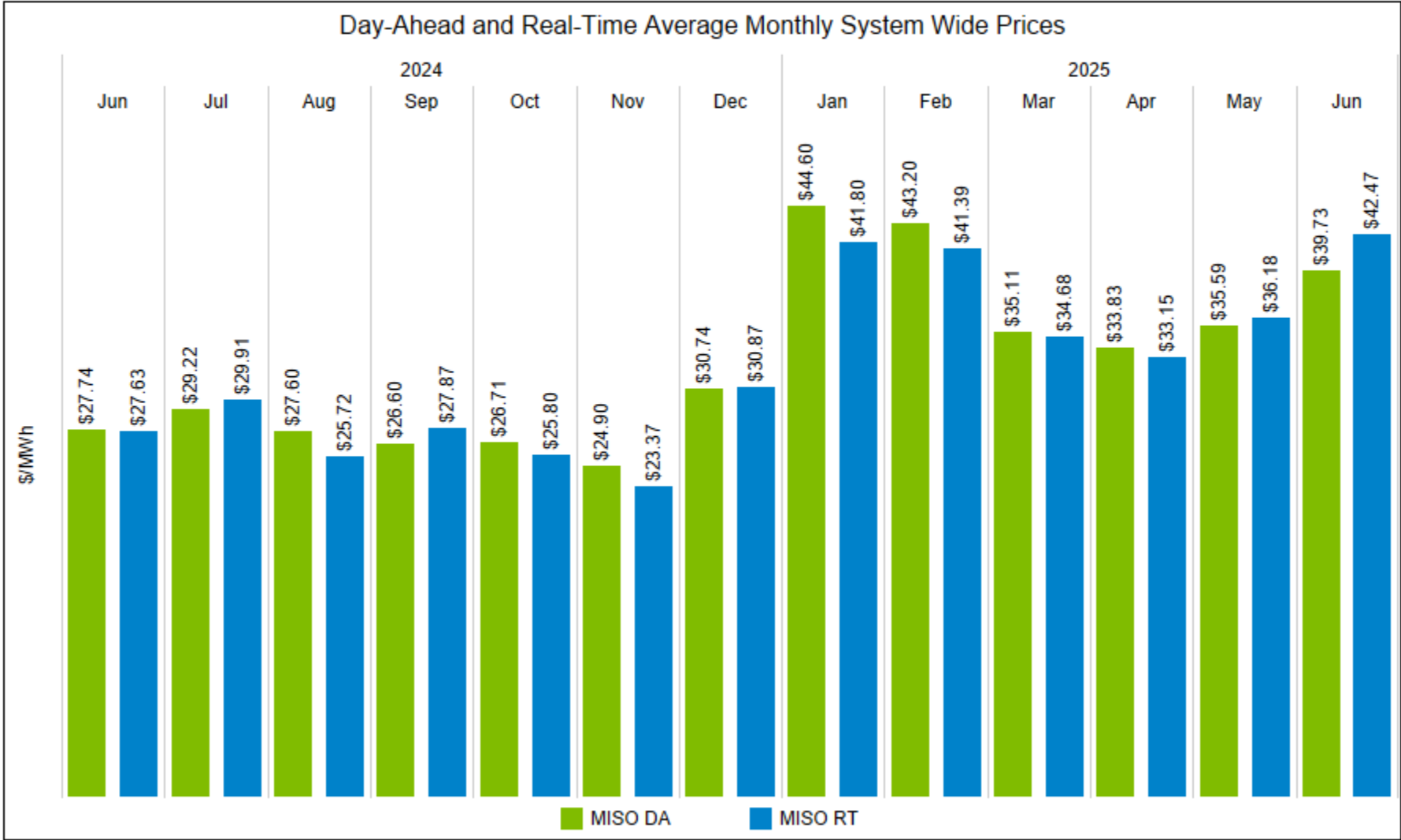
Added

- Add an Operator Actions for congestion management slide with details on Manual Redispatches/Caps
- Added a monthly solar slide that resembles the monthly wind slide
- Added a daily solar slide that resembles the daily wind slide

Contents

Pricing	MISO System-wide DA and RT LMPs	8	Generation	Marginal Fuel	34
	Price Convergence: DA and RT LMP	9		RT Generation Fuel Mix	35
	MISO DA and RT Hub LMPs	10		Dispatched Generation Fuel Mix by Region	36
	Ancillary Services – DA and RT Market Clearing Prices	11		DA Wind Forecast Performance: MAE	37
	Ancillary Services – DA and RT Market Clearing Prices	12		DA Wind Forecast Performance: MAPE	38
	Nominal Fuel Prices	13		Monthly Wind Energy	39
Settlements	Monthly Average Gross Virtual Profitability	14		Daily Wind Generation and Curtailment	40
	Daily Gross Cleared Virtual Profitability	15		DA Solar Forecast Performance: MAE	41
	DA Congestion Collections	16		DA Solar Forecast Performance: MAPE	42
	Real-Time Congestion Dollars by Region	17		Monthly Solar Energy	43
	FTR Monthly and YTD Allocation Funding	18		Daily Solar Generation and Curtailment	44
	Market Efficiency Metric	19		Carbon Emissions	45
	DA and RT Revenue Sufficiency Guarantee	20		Monthly Generation Outages and Derates	46
	Price Volatility and Make Whole Payment	21		Generation Outages by Fuel	47
	DA and RT Cleared Physical Energy	22	Reliability	Transmission Outages	48
Load	Monthly System Load and Temperature	23		Inadvertent Balance	49
	Day-Ahead Mid-Term Load Forecast	24		Generation Notifications	50
	Short-Term Load Forecast	25		Tie Line and BAAL Performance	51
	Average Load by Region	26		CPS1 Performance	52
	Market Participant Entered LMR Availability	27		Reliability – Other Metrics	53
	Regional Directional Transfer	28		Operator Actions: Manual Redispatch and Caps	54
Unit Commitment	Unit Commitment Efficiency	29	Transmission Planning	Transmission Service Request	55
	DA Supply and RT Obligation at the Peak Load Hour	30		Generator Suspension/ Retirement – New and Resolved	56
	Self-Committed and Economically Dispatched Energy	31		Generation Suspension/Retirement – Overall	57
	Trend in Self Commitment and Economically Dispatched Energy	32	Customer Service	Settlements/Customer Service	58
	Offered Capacity and RT Peak Load Obligation	33		Market Operations IT Applications Availability	59

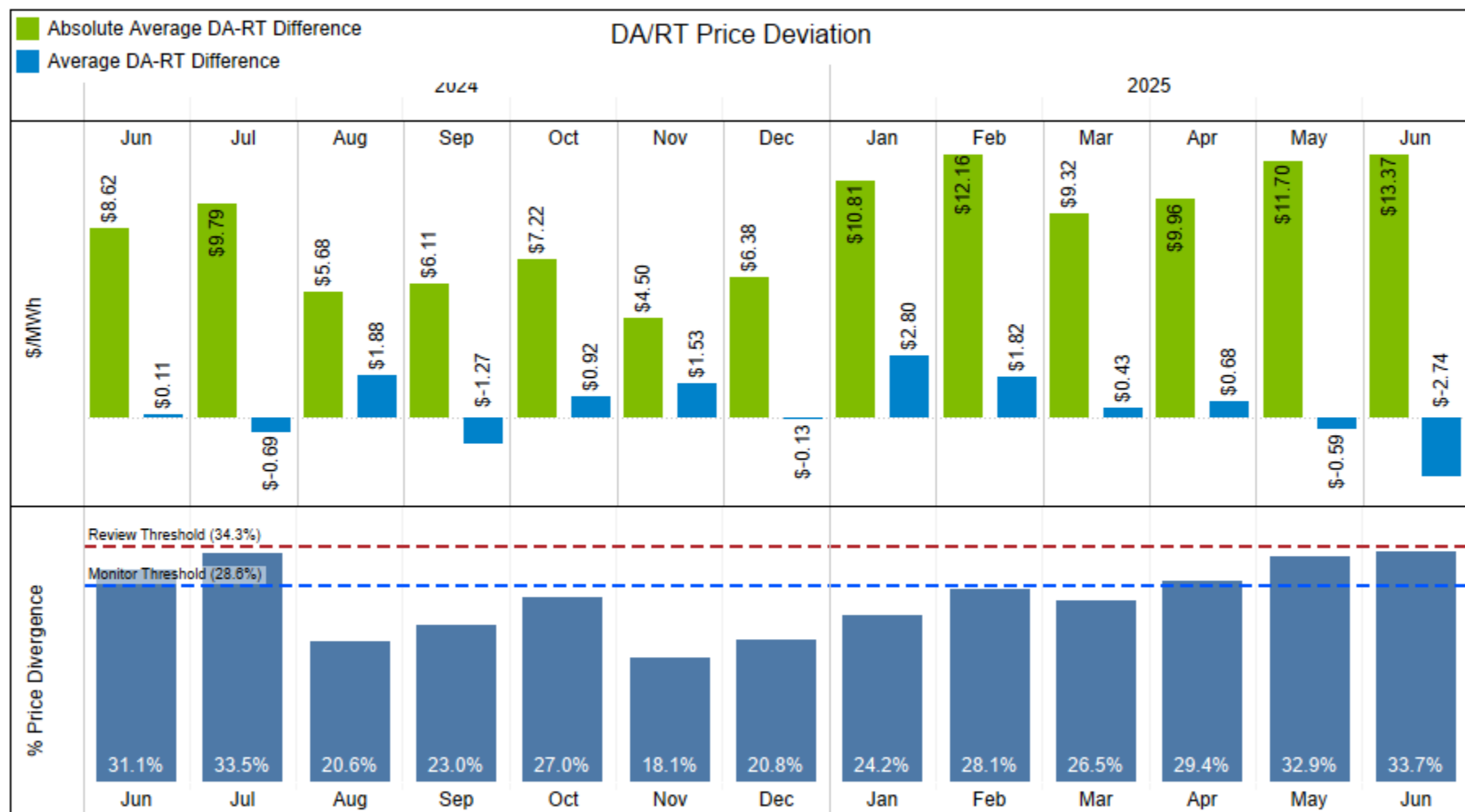
MISO System-wide Day-Ahead and Real-Time Locational Marginal Pricing



Note: MISO System-Wide price is based on the monthly hourly average of the active hubs
Source: MISO Market and Operations Analytics Department

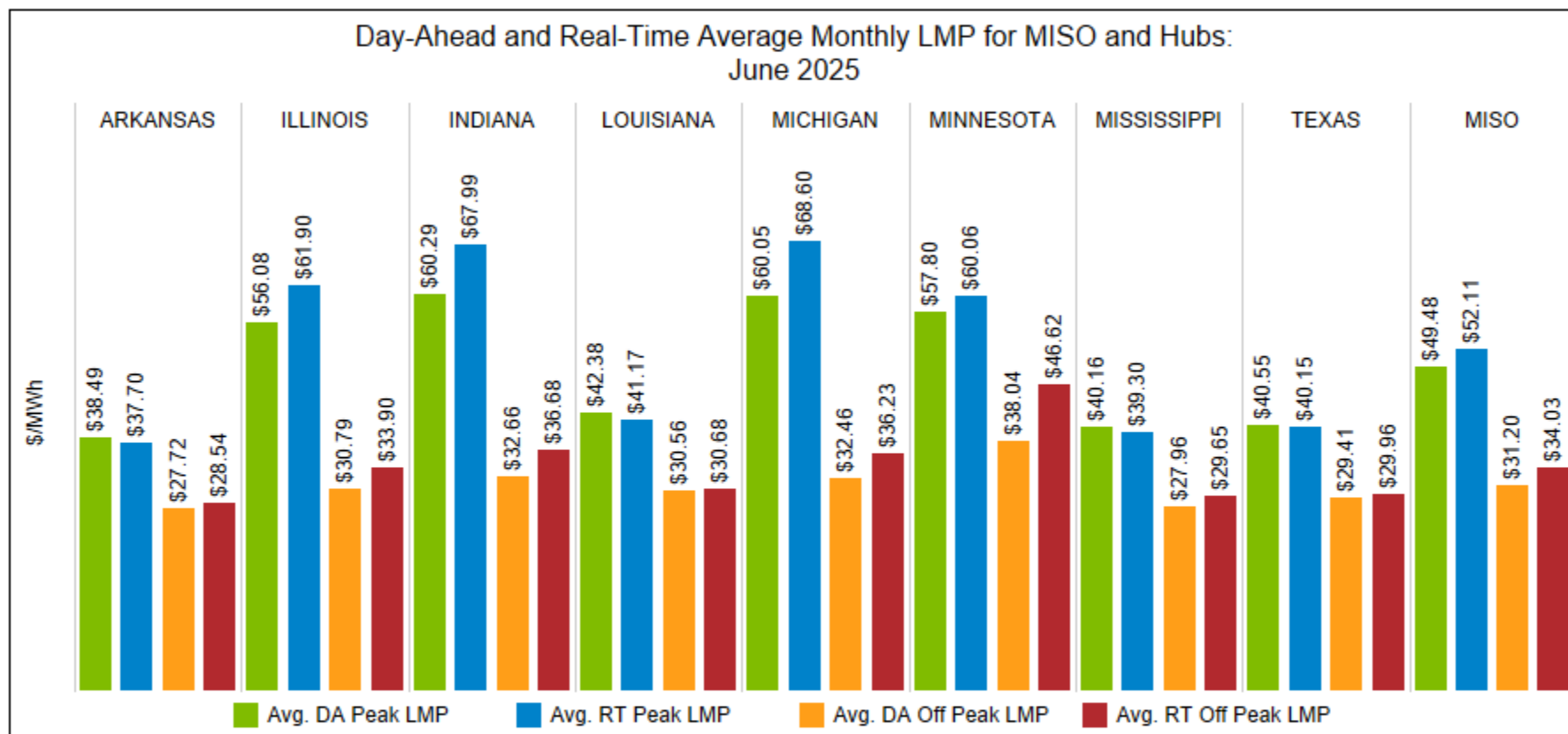
Price Convergence: Day-Ahead and Real-Time Locational Marginal Pricing

A



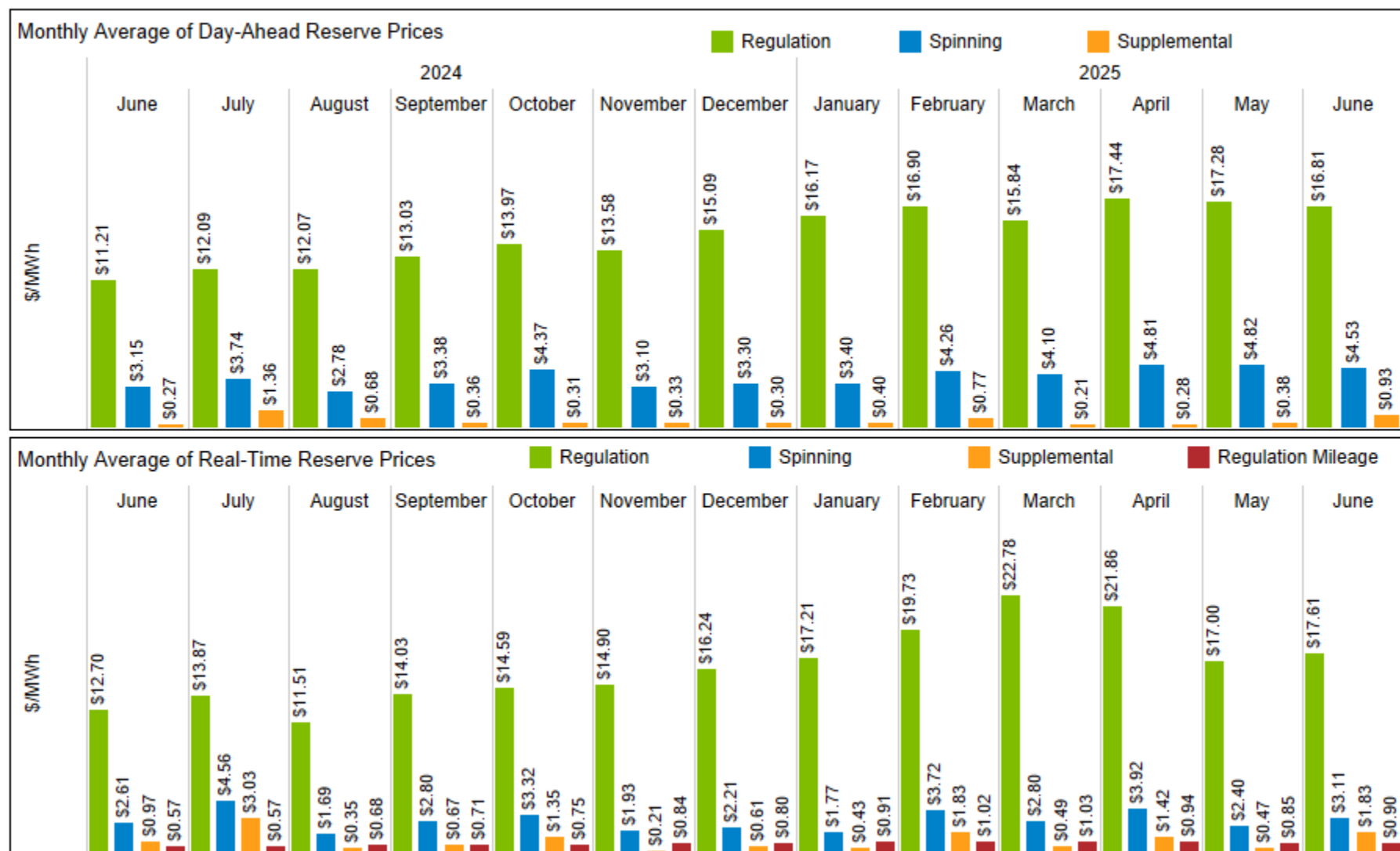
*Monthly deviation, expressed as a percent of average DA LMP, is calculated as the average of hourly absolute (DA-RT) price difference divided by the average of hourly DA LMPs for the month

MISO Day-Ahead and Real-Time Hub Locational Marginal Pricing

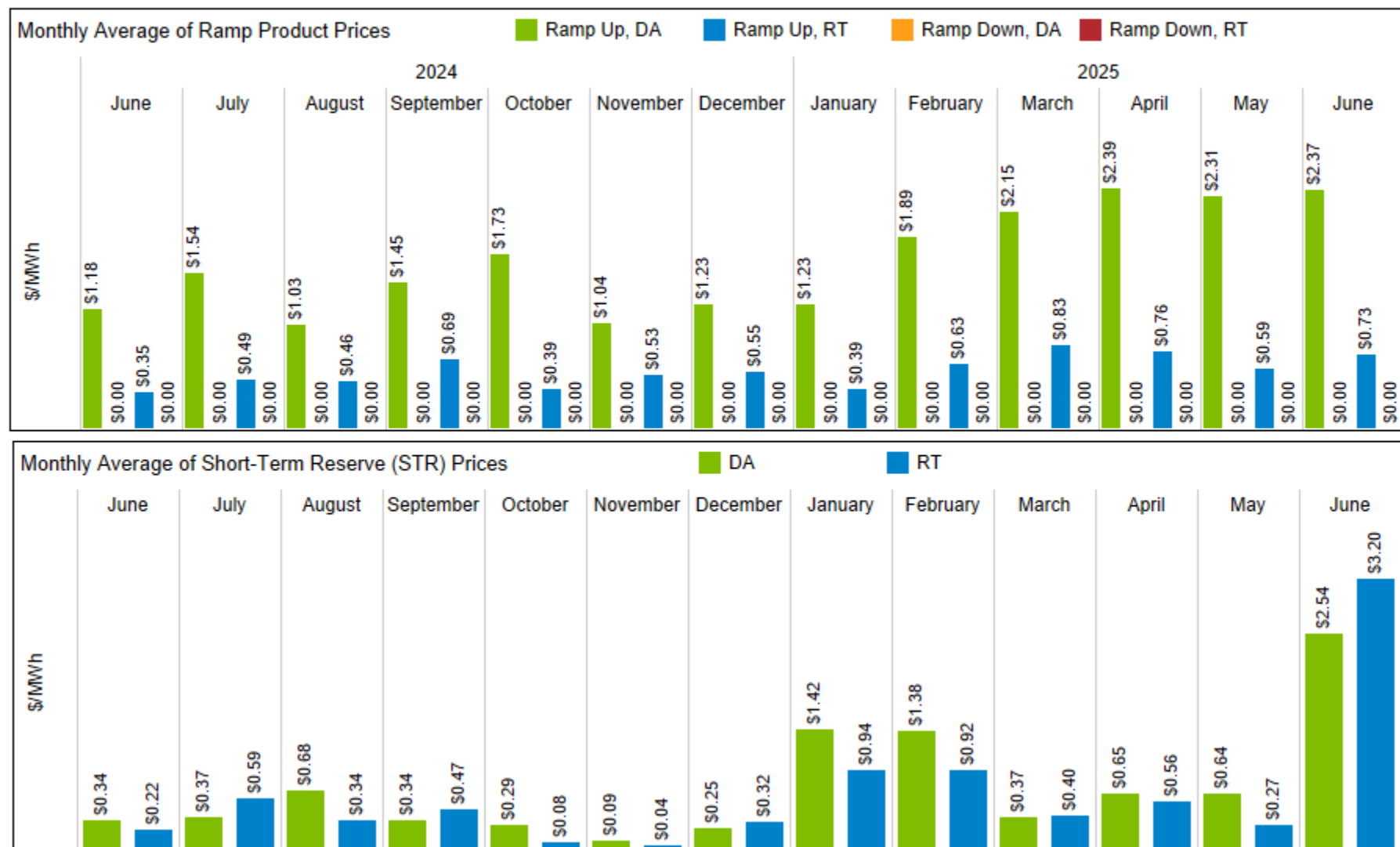


		ARKANSAS	ILLINOIS	INDIANA	LOUISIANA	MICHIGAN	MINNESOTA	MISSISSIPPI	TEXAS	MISO
Marginal Congestion Component of LMP (\$/MWh)	DA Peak	-16.62	-0.48	1.78	-14.90	1.82	-0.63	-16.19	-15.79	-7.63
	RT Peak	-23.91	-1.42	2.06	-22.70	2.91	-2.36	-23.51	-23.17	-11.51
	DA Off Peak	-3.55	-0.81	-0.24	-2.16	-0.23	5.13	-3.96	-2.61	-1.06
	RT Off Peak	-5.71	-0.78	0.54	-5.11	0.35	10.78	-5.28	-5.53	-1.34

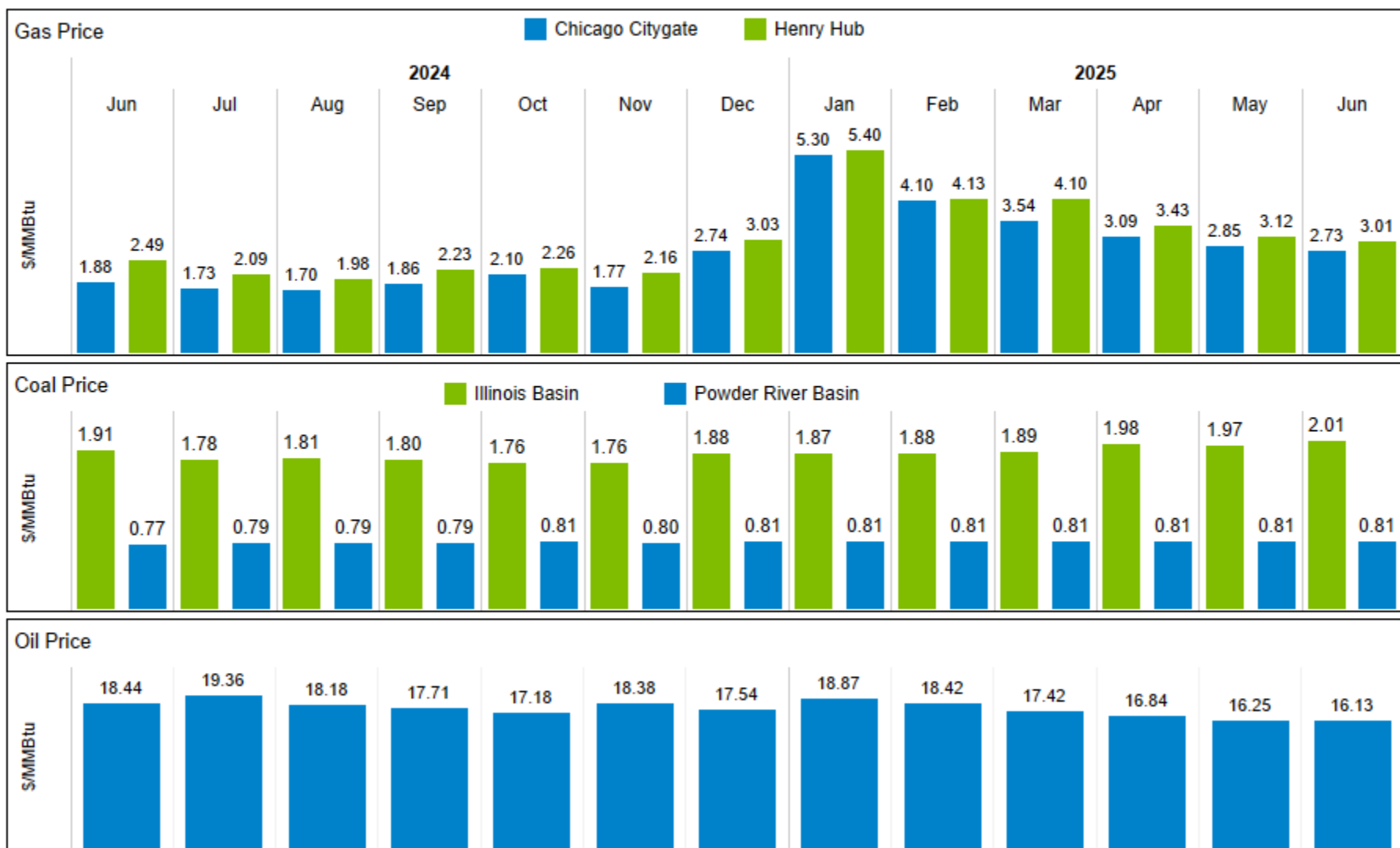
Ancillary Services - Day-Ahead and Real-Time Market Clearing Prices



Ancillary Services - Day-Ahead and Real-Time Market Clearing Prices



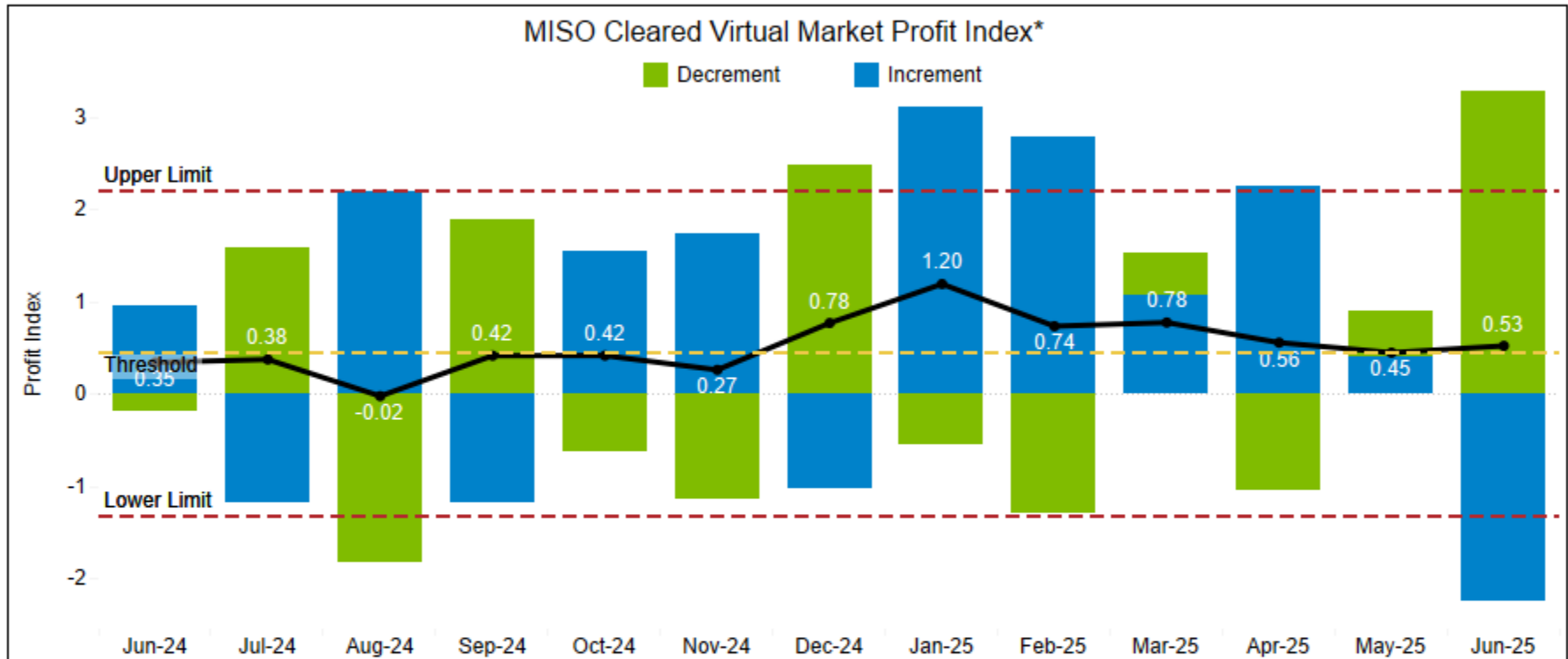
Nominal Fuel Prices



Monthly oil prices are estimates and subject to change upon finalization
Source: EIA

Monthly Average Gross Virtual Profitability

B



Monthly Standard Deviation

Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25
1.09	2.96	0.86	1.32	1.21	1.74	1.50	2.60	2.21	1.16	1.15	2.04	1.61

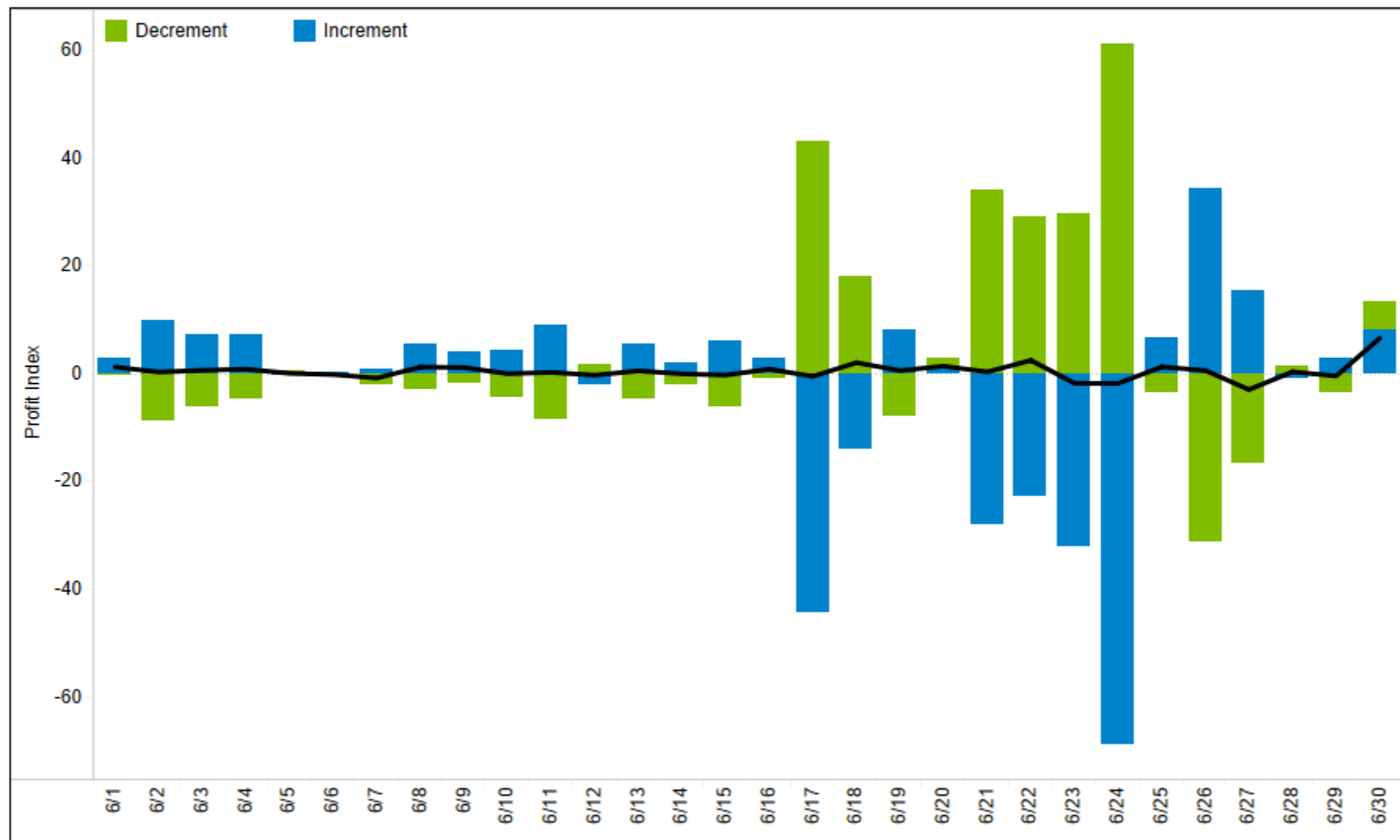
* The virtual profitability market index is defined as the sum of profits/losses for all cleared virtual transactions divided by the volume (MWh) of total cleared transactions.

* Virtual profits/losses are calculated by multiplying the cleared virtual MW and the imbalance between RT LMP and DA LMP for a cpnode, then summed across all cpnodes, all hours.

* Upper Limit is Threshold (average of monthly indices from the previous year) plus Daily Average Standard Deviation for the previous 13 months (current reporting month inclusive)

* Lower Limit is Threshold (average of monthly indices from the previous year) minus Daily Average Standard Deviation for the previous 13 months (current reporting month inclusive).

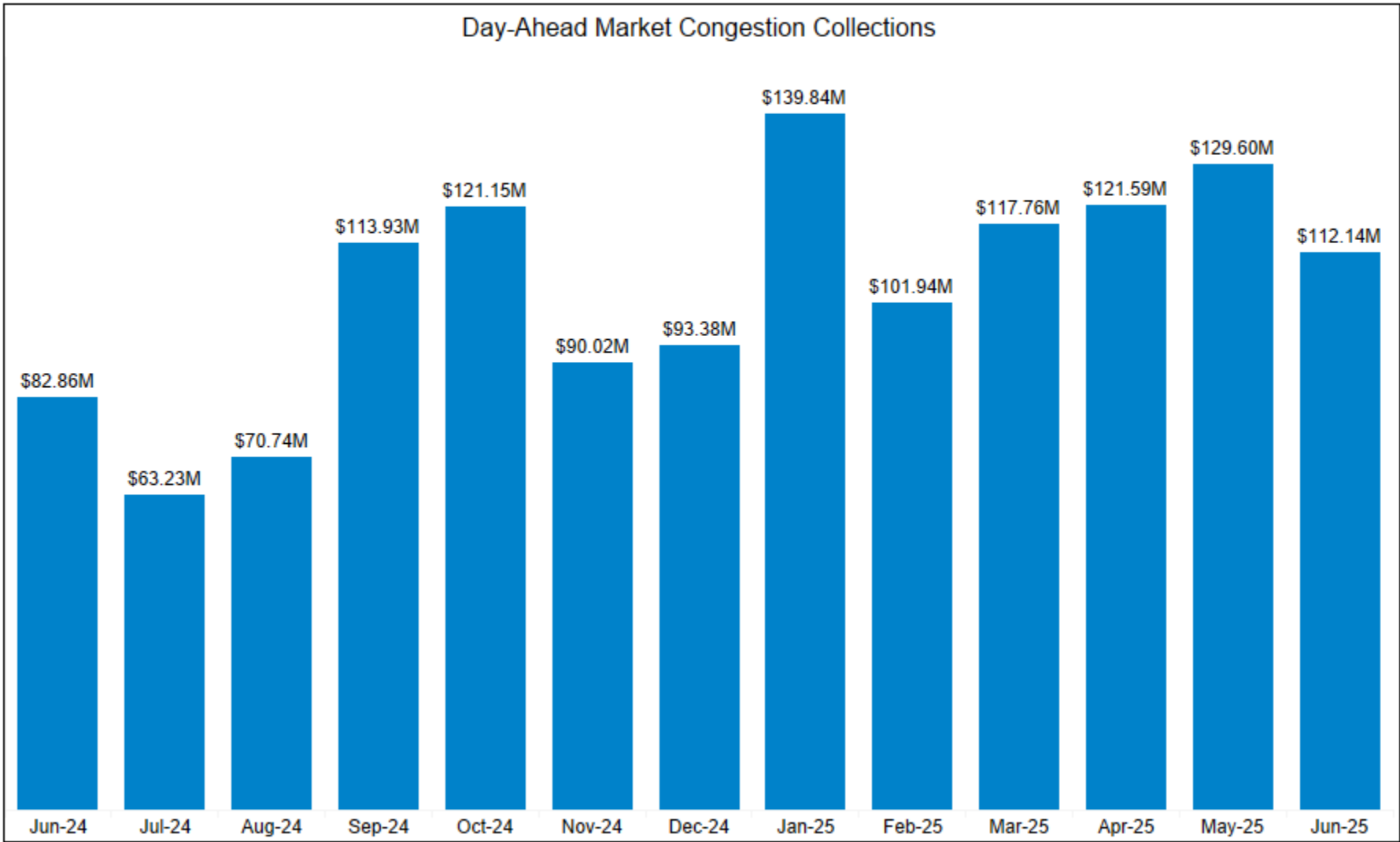
Daily Gross Cleared Virtual Profitability



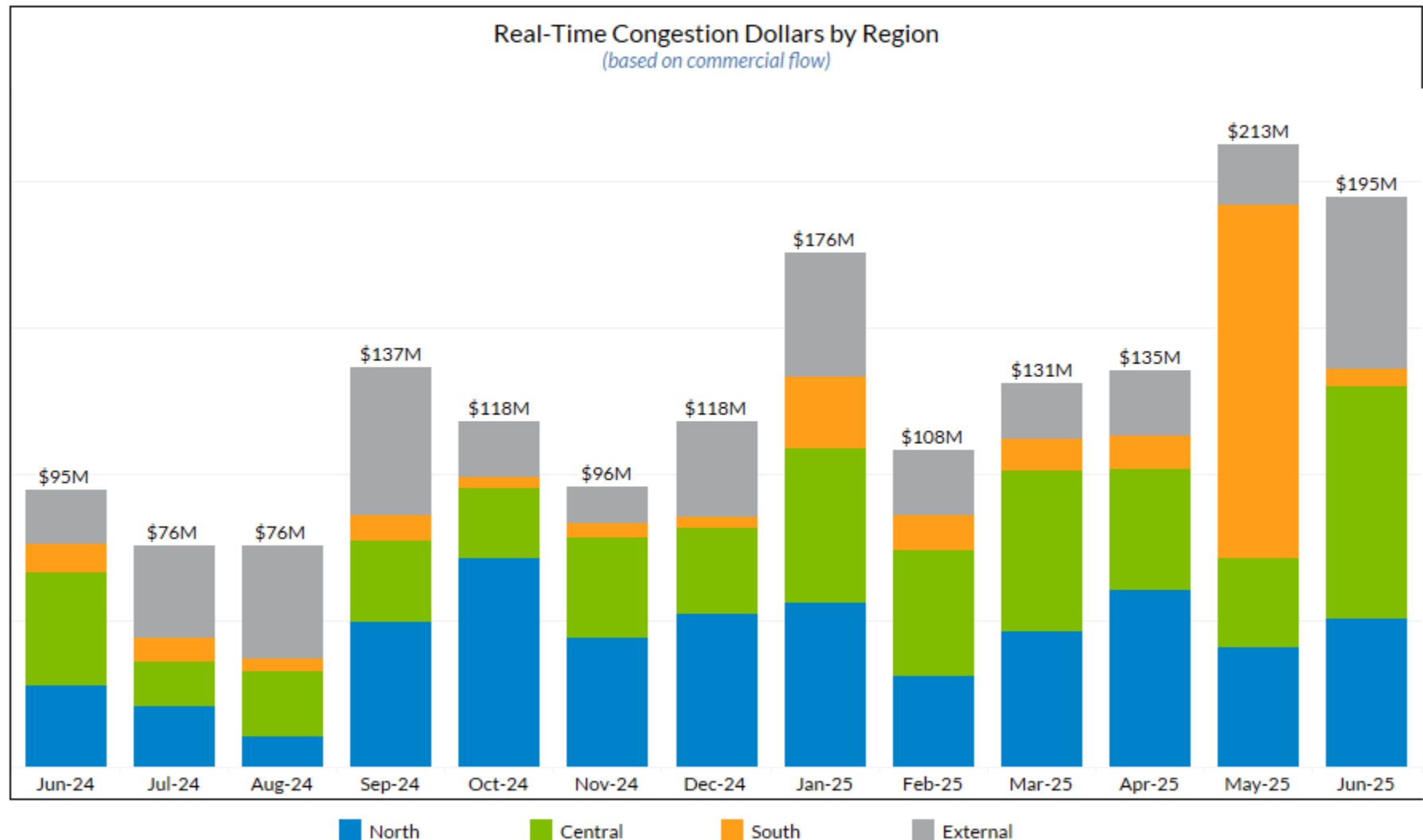
The virtual profitability market index is defined as the sum of profits/losses for all cleared virtual transactions divided by the volume (MWh) of total cleared transactions

Source: MISO Market and Operations Analytics Department

Day-Ahead Congestion Collections



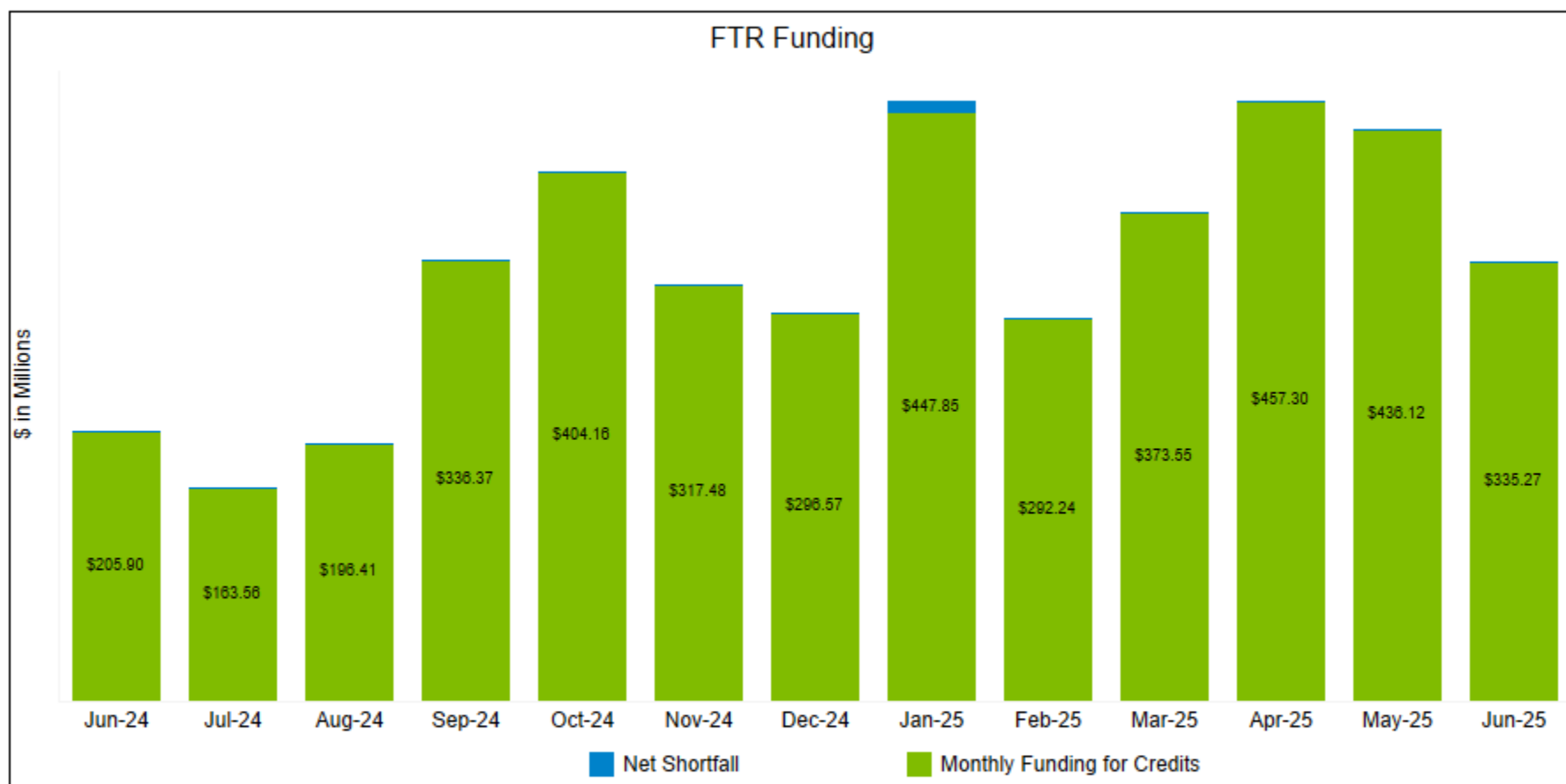
Real-Time Congestion Dollars by Region



Includes External Constraints
Commercial Flow excludes phase angle regulators and loop flows
Source: MISO Market and Operations Analytics Department

Financial Transmission Rights, Monthly and Rolling Year-to-Date Allocation Funding

C

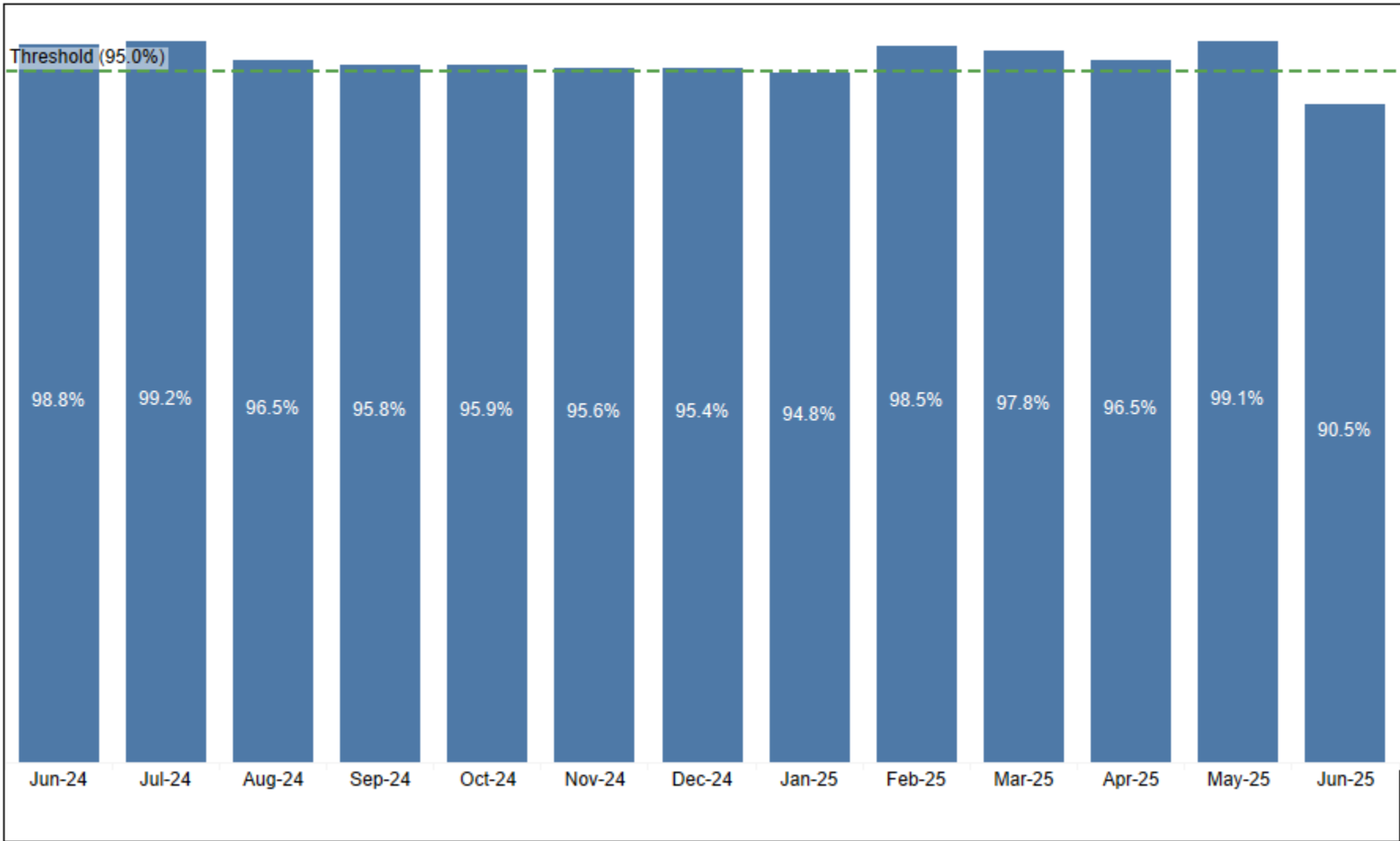


	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25
Monthly FTR Allocation (%)	100.0%	100.0%	100.0%	99.9%	100.0%	100.0%	100.0%	97.8%	100.0%	100.0%	100.0%	100.0%	100.0%
YTD FTR Allocation (%)	95.6%	96.3%	96.7%	97.1%	97.5%	97.8%	98.0%	NA	NA	NA	100.0%	100.0%	100.0%

YTD metric is applied beginning April
 Values may change due to resettlement
 Source: MISO Market ECF Report

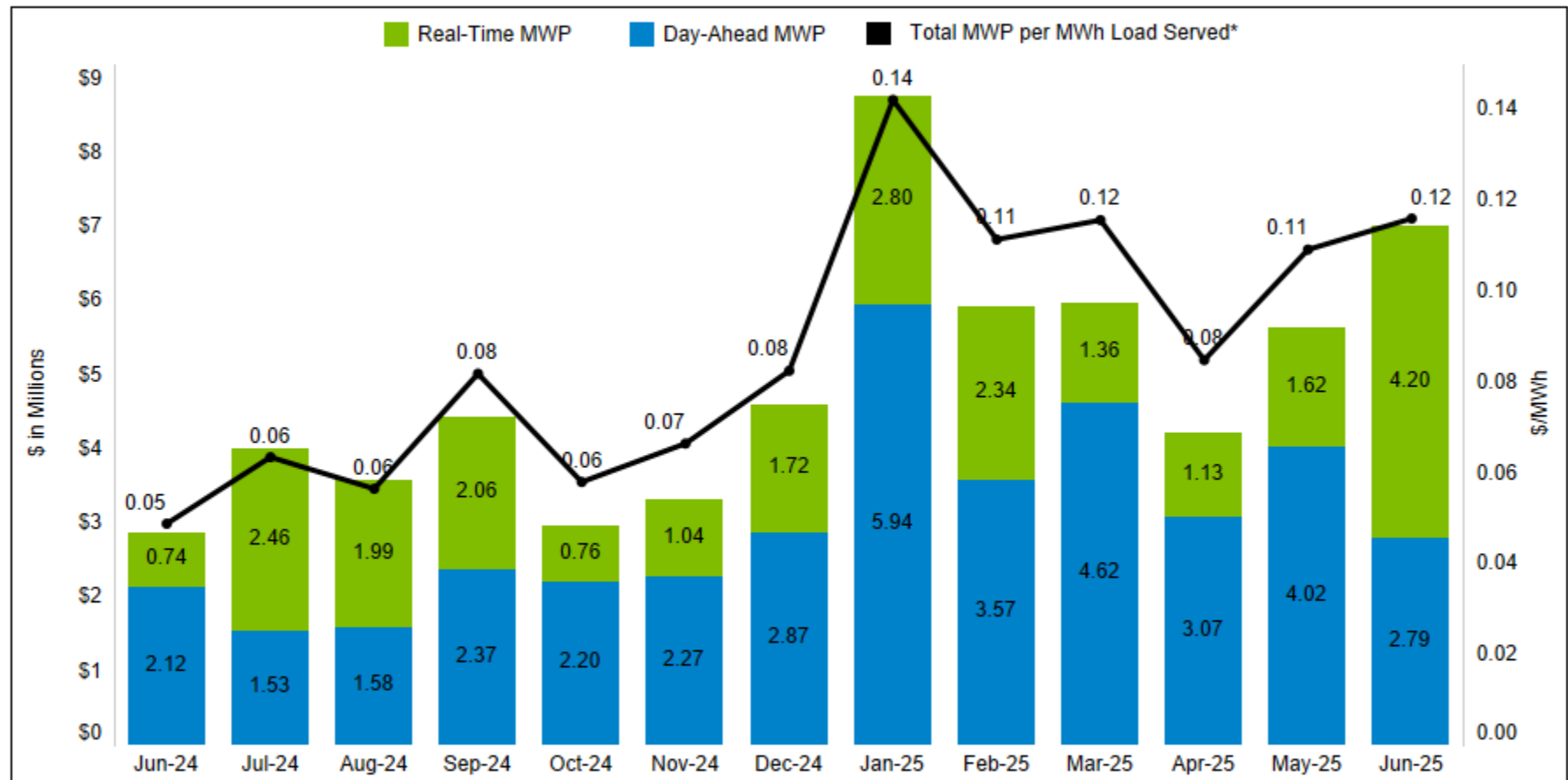
Market Funding Efficiency

D



Values may change due to resettlement
Source: MISO Market ECF Report

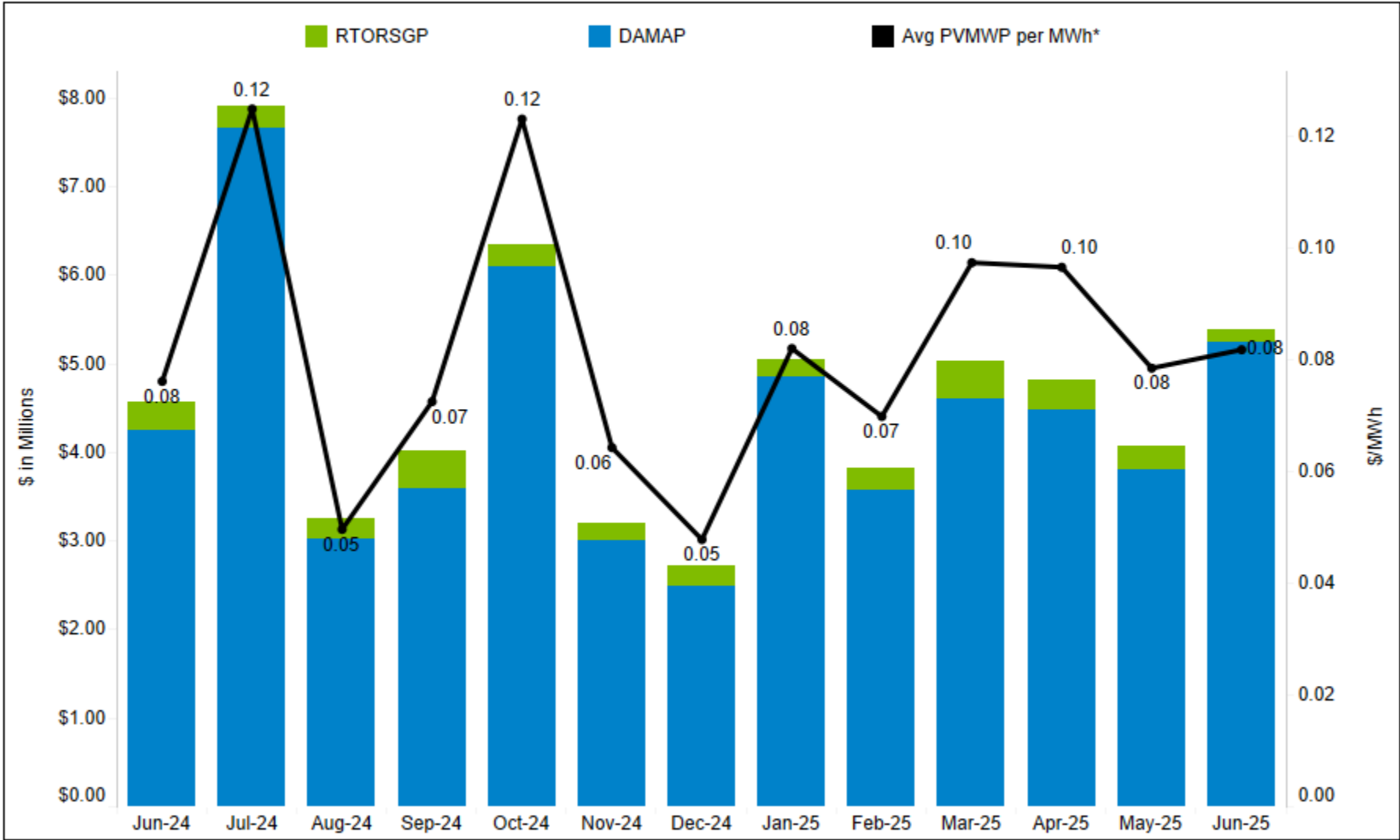
Day-Ahead and Real-Time Revenue Sufficiency Guarantee E



	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25
Chicago Gas Prices (\$/MMBtu)	1.88	1.73	1.70	1.86	2.10	1.77	2.74	5.30	4.10	3.54	3.09	2.85	2.73
Henry Gas Prices (\$/MMBtu)	2.49	2.09	1.98	2.23	2.26	2.16	3.03	5.40	4.13	4.10	3.43	3.12	3.01
^^RSG Per MWh to Energy Price (%)	0.18	0.22	0.20	0.31	0.22	0.27	0.27	0.32	0.26	0.33	0.25	0.31	0.29

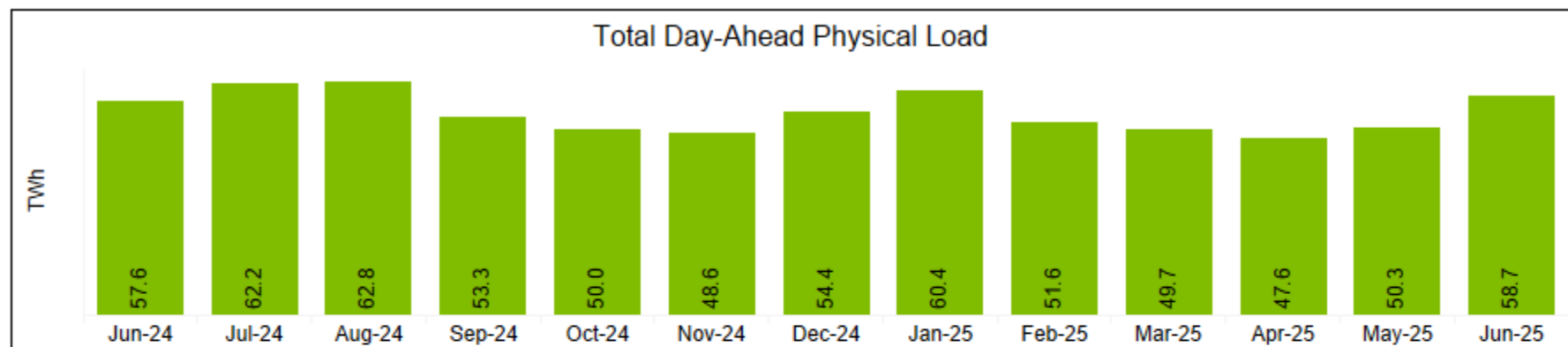
*Based on hourly ICCP Data; ^^metric value
 Values may change due to resettlement
 Source: The Web-based Revenue Sufficiency Guarantee Report

Price Volatility Make Whole Payment



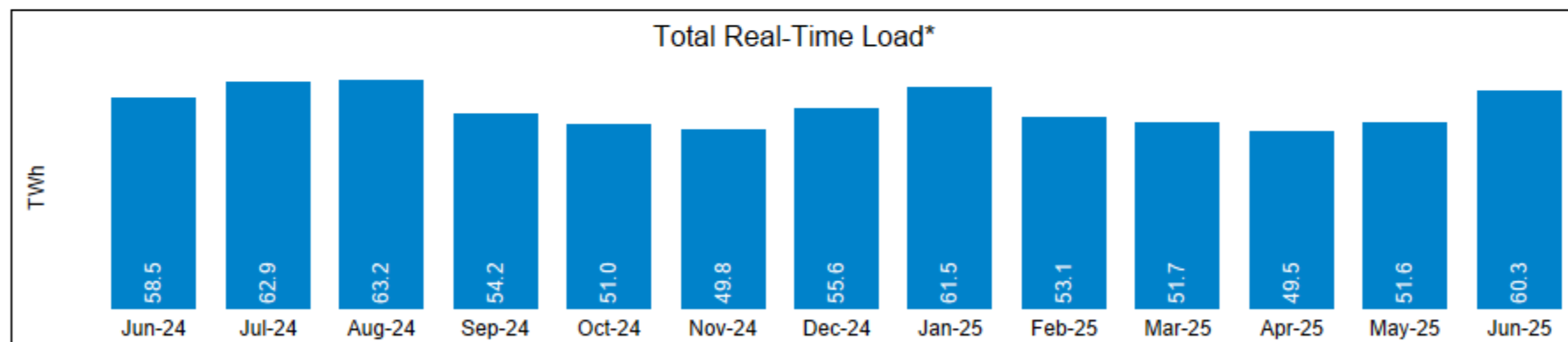
*Hourly ICCP data
Source: Web-based Revenue Neutrality Uplift Report

Day-Ahead and Real-Time Cleared Physical Energy



Day-Ahead Cleared Load Value (including Virtuals)

Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25
\$1.92B	\$2.37B	\$2.20B	\$1.74B	\$1.57B	\$1.44B	\$2.06B	\$3.20B	\$2.68B	\$1.93B	\$1.87B	\$2.14B	\$2.97B

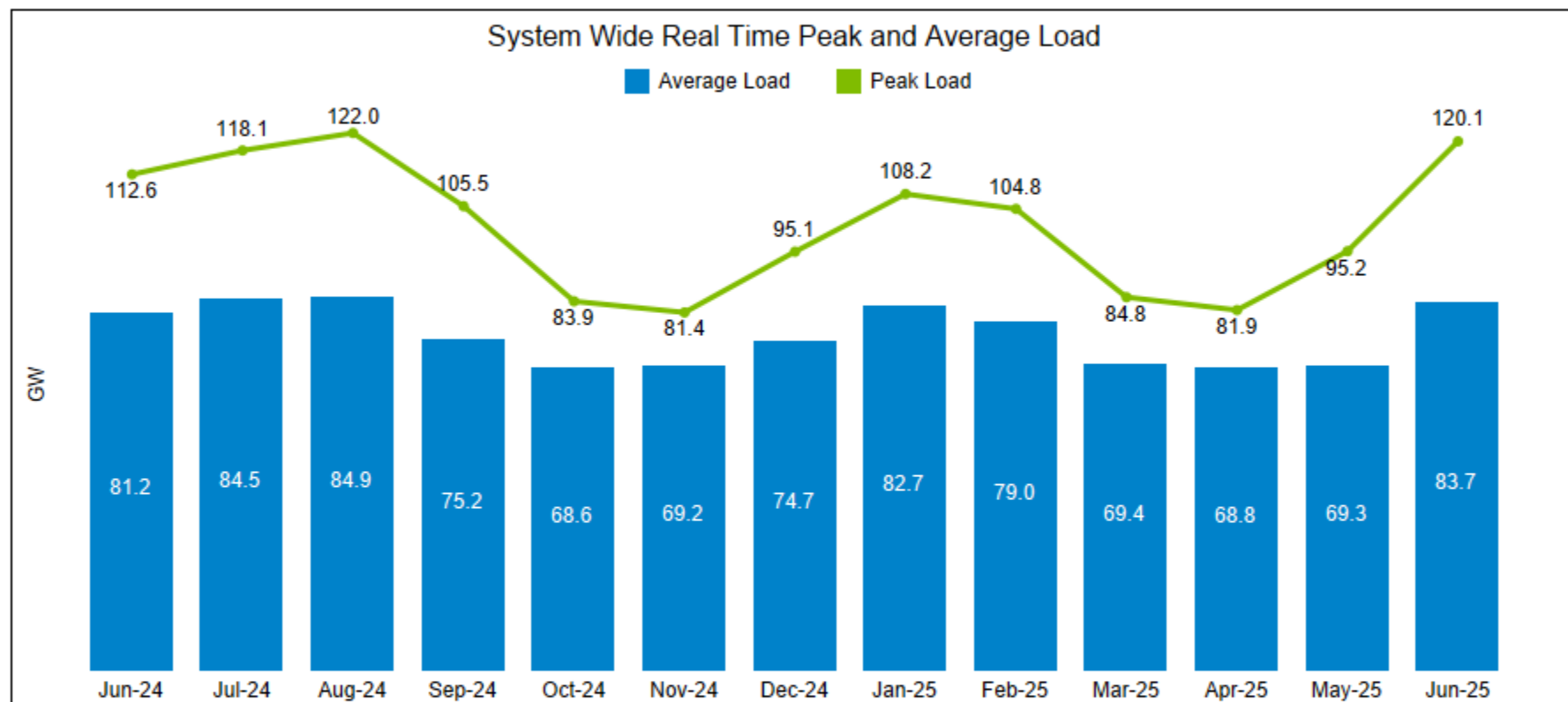


Real-Time Cleared Load Value (\$ in Billions)

Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25
\$1.66B	\$2.14B	\$1.81B	\$1.63B	\$1.29B	\$1.18B	\$1.83B	\$2.64B	\$2.21B	\$1.65B	\$1.55B	\$1.95B	\$3.00B

*Sum of Hourly ICCP Load Data
Source: MISO Market and Operations Analytics Department

Monthly System Load and Temperature



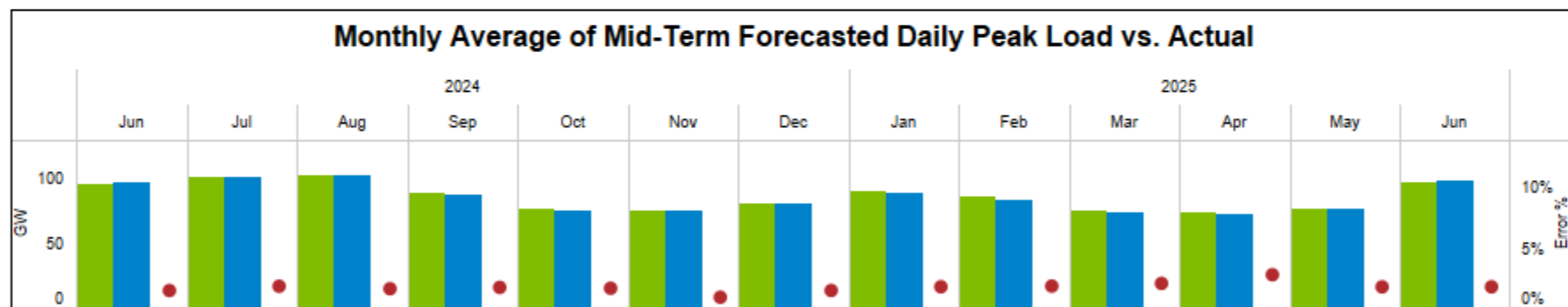
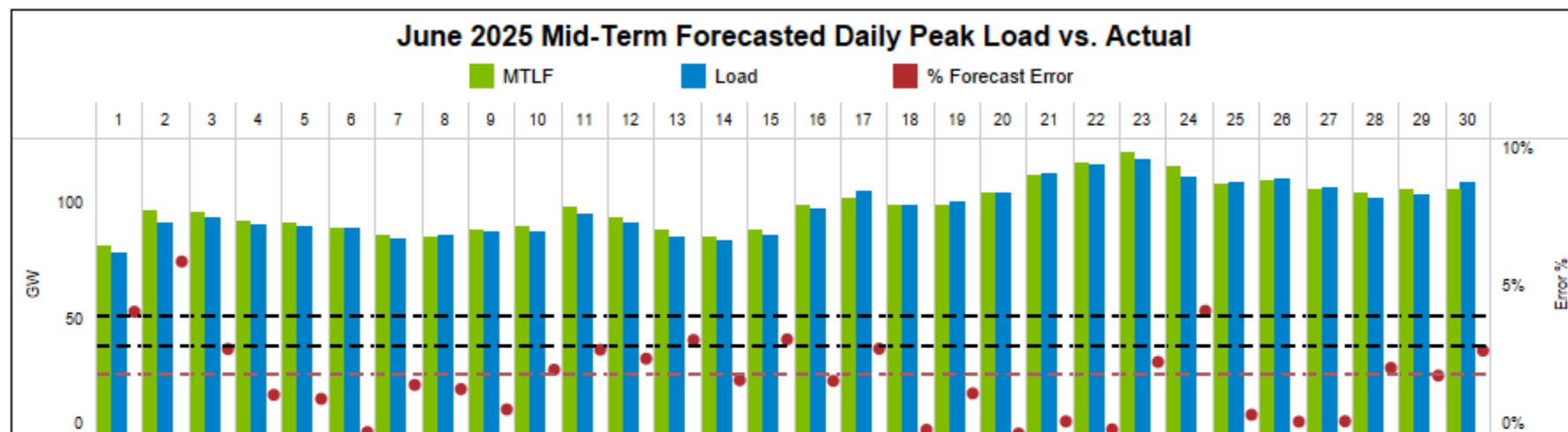
System Wide Load Weighted Temperature			
	Jun-24	May-25	Jun-25
Average	77°F	63°F	76°F
Maximum	93°F	83°F	100°F
Minimum	55°F	47°F	52°F

Load Weighted Heating & Cooling Degree Days				
	Average HDD	Std Dev HDD	Average CDD	Std Dev CDD
Jun-25	0.14	0.94	14.60	8.60
May-25	2.30	3.41	3.73	4.90
Jun-24	0.07	0.56	14.60	7.77

Hours with Load Greater than:			
	100 GW	80 GW	60 GW
Jun-25	110	415	709
May-25	0	62	653
Jun-24	67	364	695

Day-Ahead Mid-Term Load Forecast*

F



	2024							2025					
	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
% Std of Error (CV)	90.18	76.54	67.80	71.09	68.94	101.98	81.76	77.55	60.87	54.00	40.07	78.67	71.95
Mean of Error (MW)	1,594	1,980	1,845	1,700	1,418	814	1,334	1,742	1,674	1,671	2,191	1,474	1,852
Std of Error (MW)	1,437	1,515	1,251	1,209	978	830	1,090	1,351	1,019	902	878	1,159	1,332

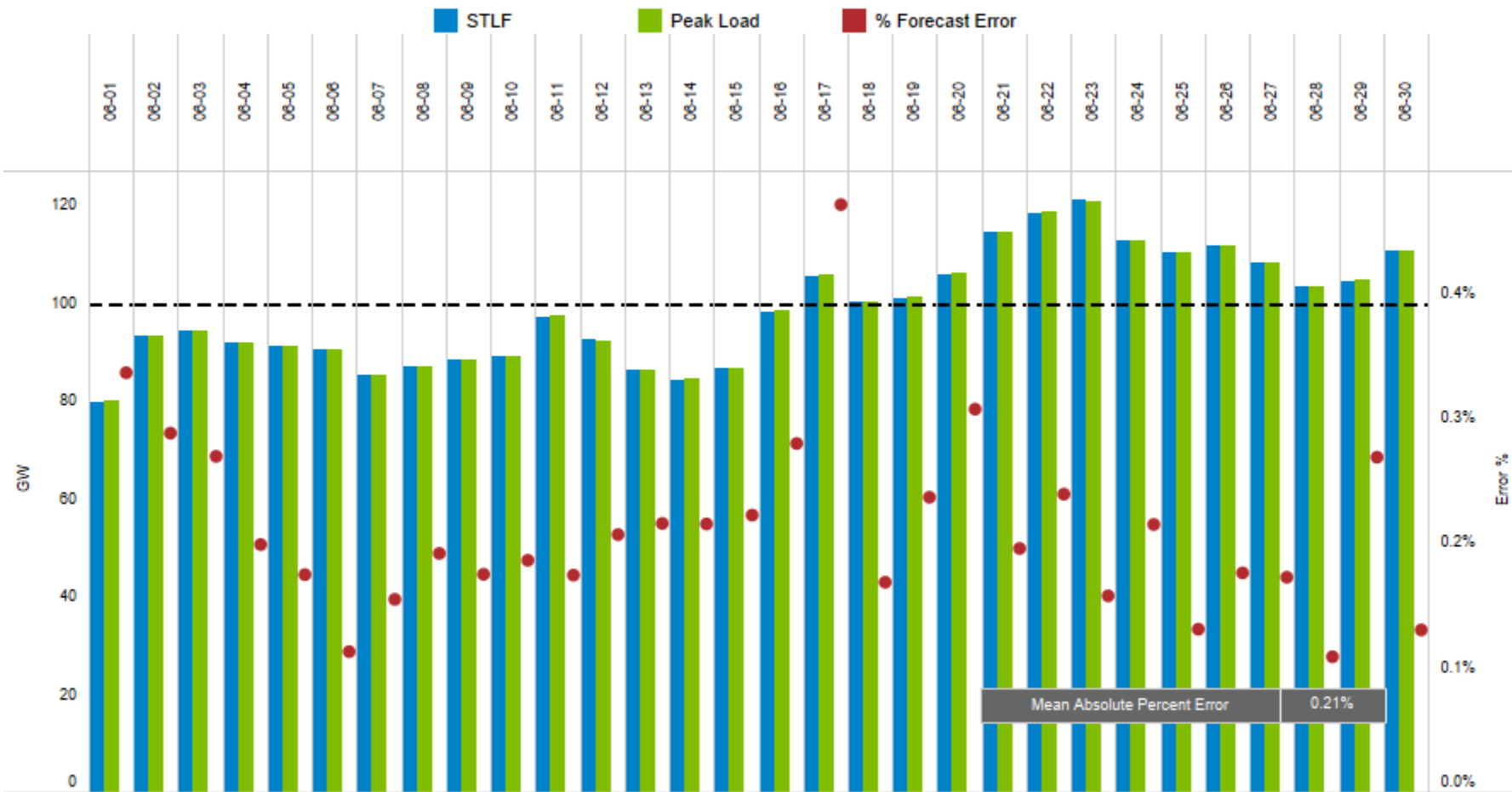
* Monthly data based on the average of the daily integrated peak hours in the month

* Daily data based on the integrated peak hour of the day

* Peak Day and Hour End based on Hourly Integrated Peak Load Hour

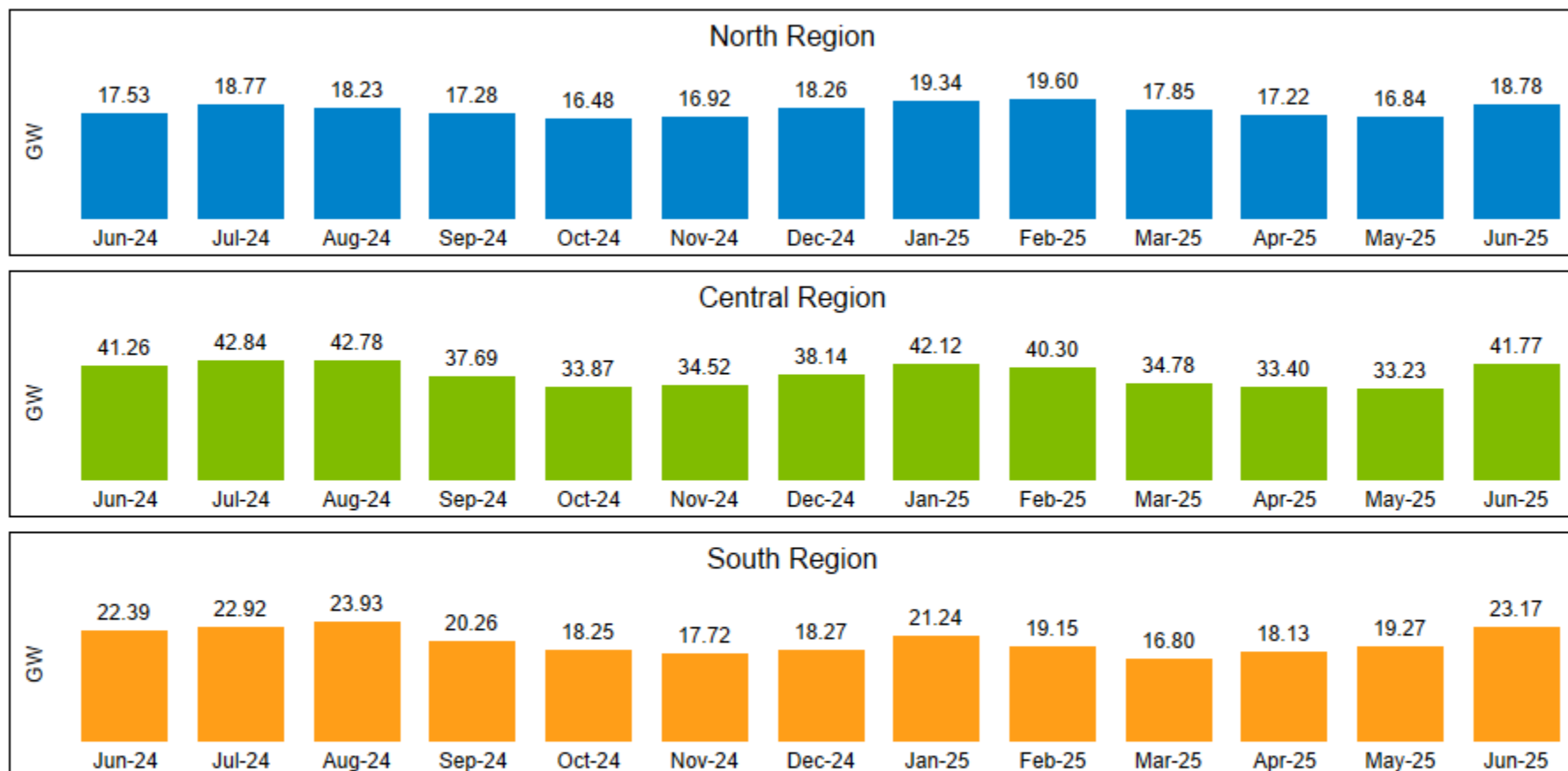
Short-Term Load Forecast*

June 2025 Short-Term Forecasted Daily Peak Load vs Actual



Daily data based on the average of five-minute interval data at the peak hour of the day
Error Threshold calculated as 95% quantile of Forecast Error from Jan-Dec of the previous year
Peak Day and Hour End based on Hourly Integrated Peak Load Hour

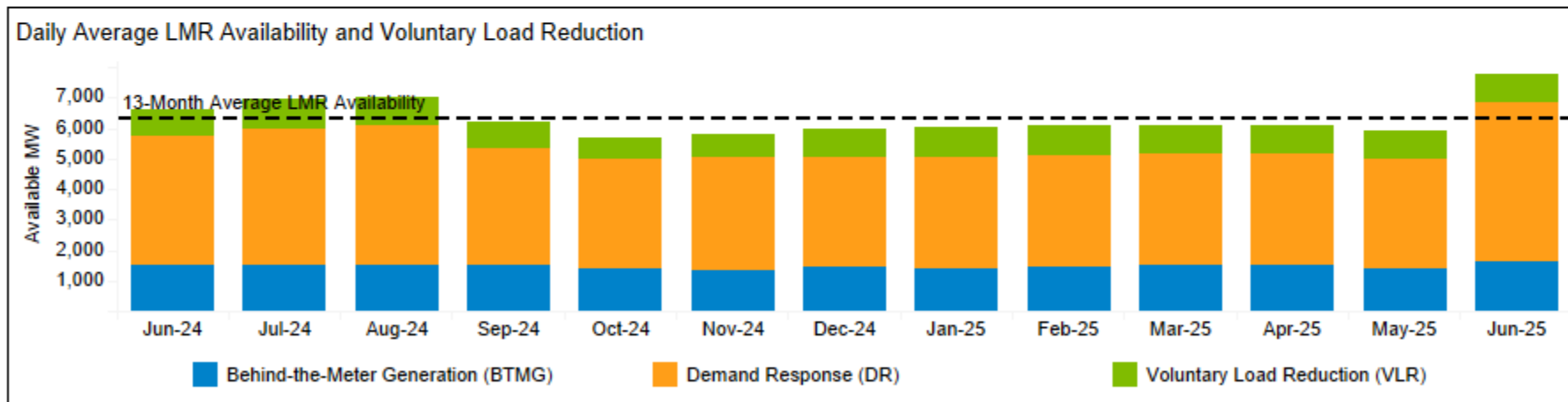
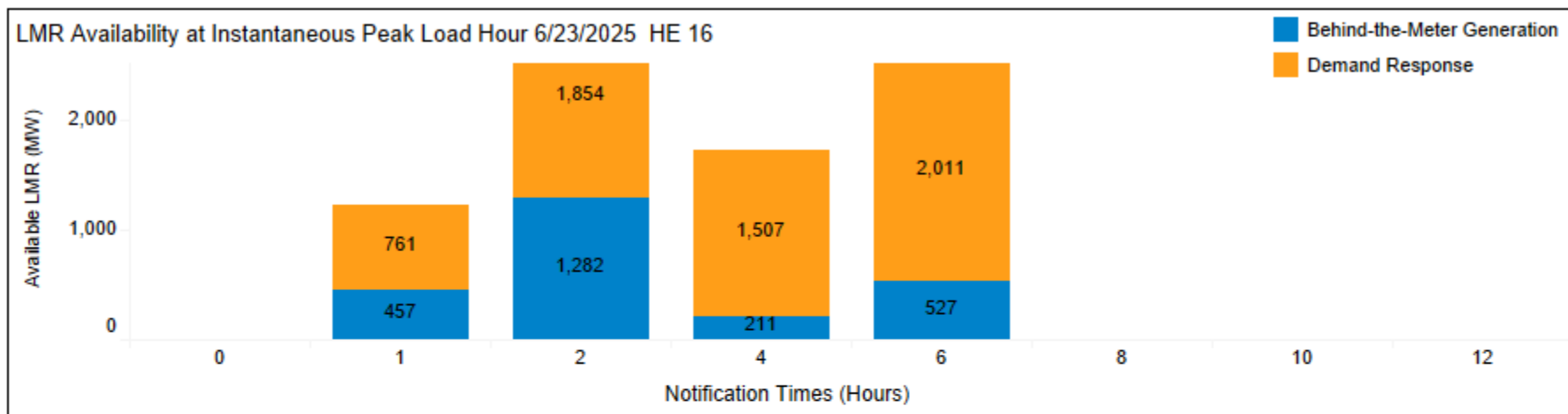
Average Load by Region



Hourly Integrated System Load Peak Hour Ending: 06/23/2025 16 EST

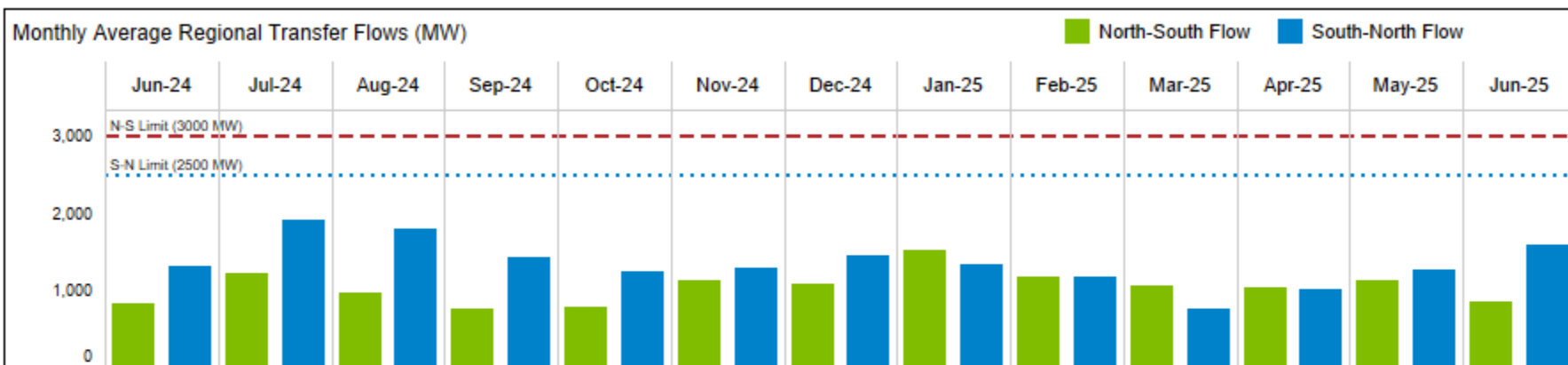
North	25.86 GW
Central	65.78 GW
South	30.29 GW
MISO	119.31 GW

Market Participant entered Load Modifying Resource (LMR) Availability



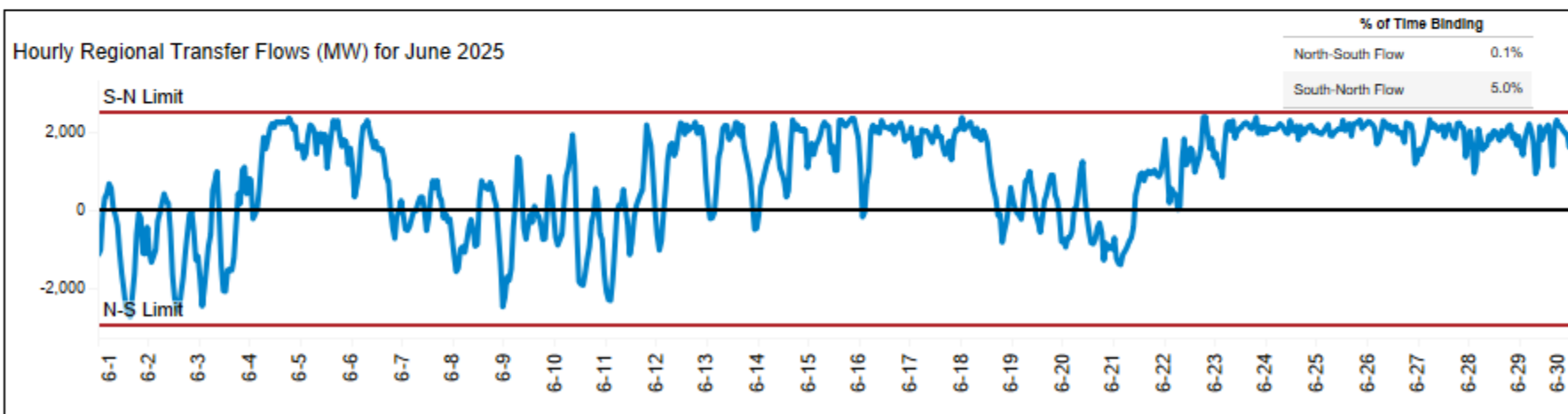
PRA Auction	BTMG (MW)	DR (MW)	Total BTMG and DR (MW)
Summer 2024	4,144	8,109	12,253
Summer 2025	4,283	9,004	13,287

Regional Directional Transfer**



Percentage of Time Regional Directional Flow

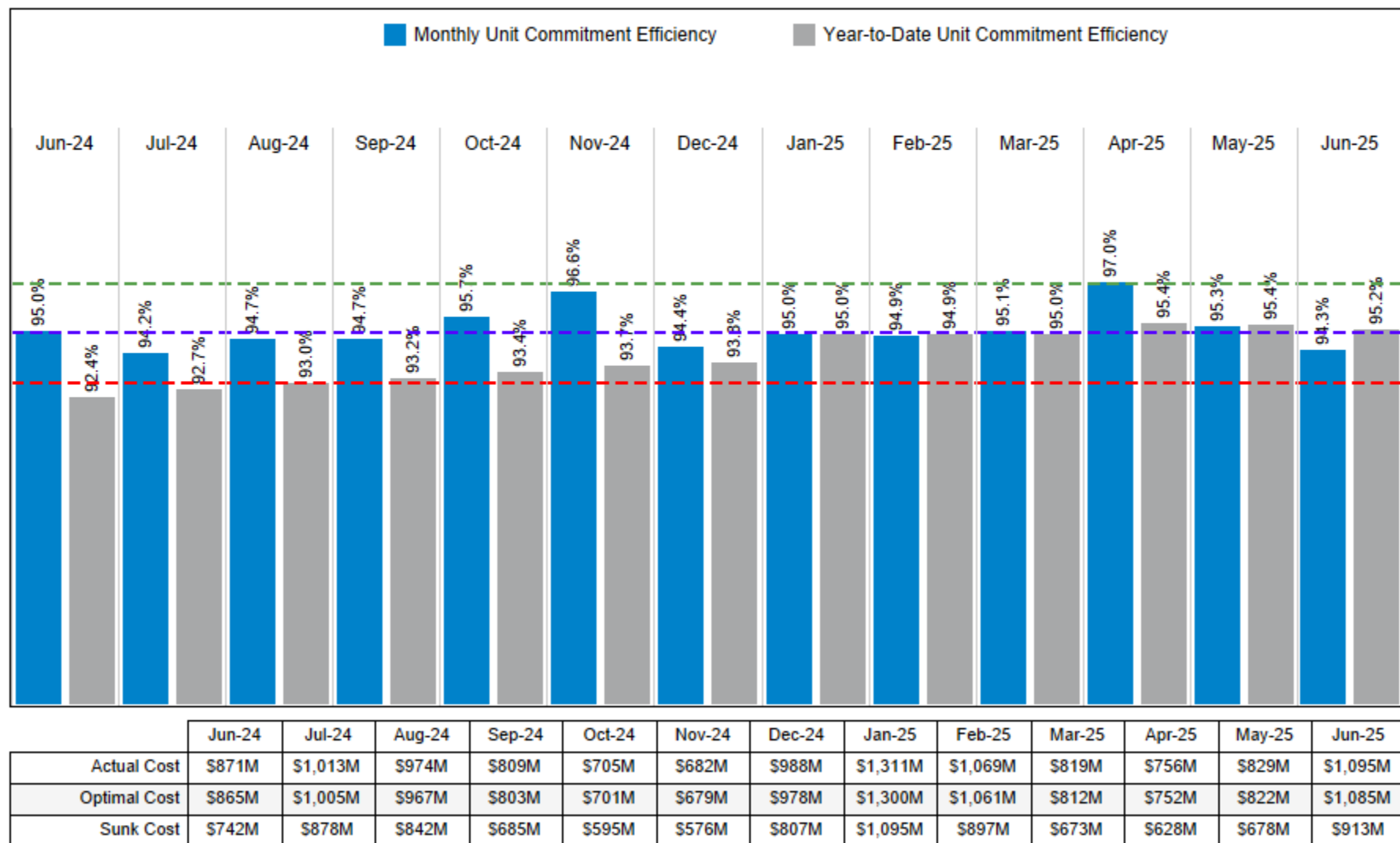
	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25
North-South Flow	34%	8%	10%	21%	17%	23%	22%	29%	40%	61%	44%	49%	26%
South-North Flow	66%	92%	90%	79%	83%	78%	78%	71%	60%	39%	56%	51%	74%



Unit Commitment Efficiency

Effectively commit generation to meet demand obligations and mitigate constraints

H

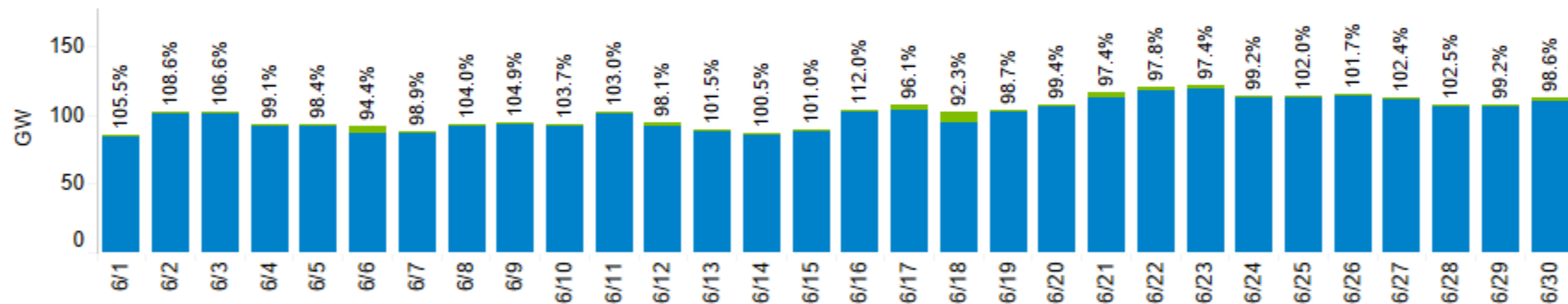
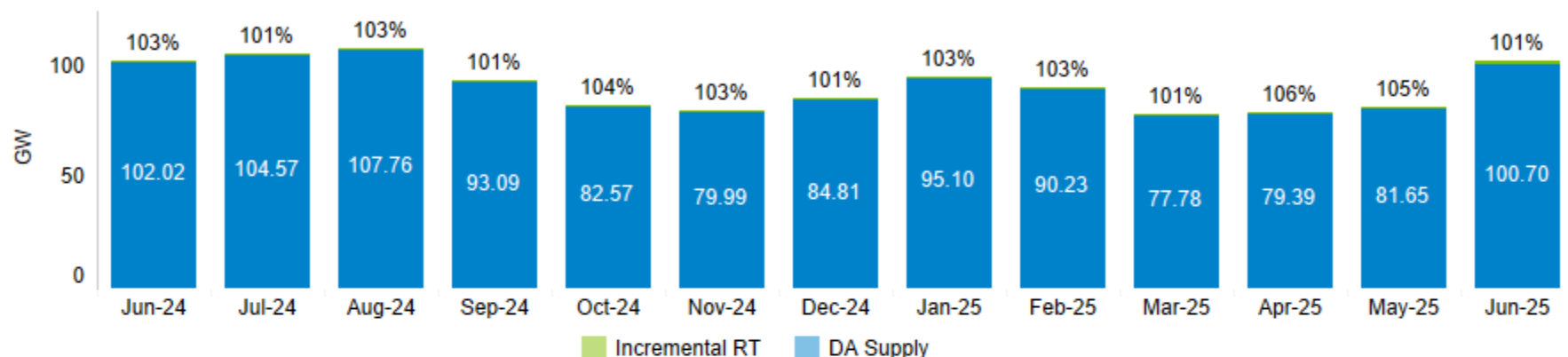


Source: MISO Optimal Dispatch Calculator (ODC)

Unit Commitment Efficiency = $1 - ((\text{Actual cost} - \text{Optimal cost}) / (\text{Actual cost} - \text{Sunk cost}))$



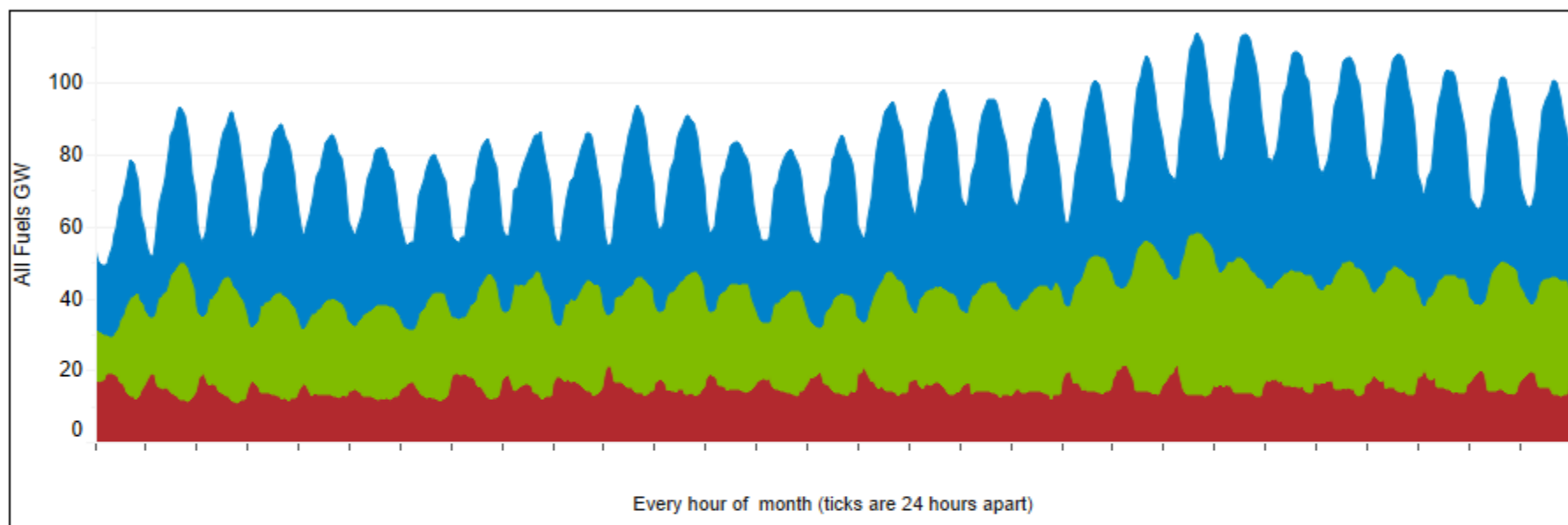
Day-Ahead Supply and Real-Time Load Obligation at the Peak Load Hour



Incremental GW Committed in Real-Time

Day-Ahead Supply is the Day-Ahead Economic Maximum received in Real-Time plus Behind-the-Meter plus Day-Ahead NSI at the Peak Hour
 Real-Time Obligation is the Real-Time ICCP Load plus Real-Time Regulation Requirement plus Real-Time Spinning Requirement at the Peak Hour
 Real-Time Increment is the Real-Time Obligation less Day-Ahead Supply at the Peak Hour
 Percents calculated as Day-Ahead Supply divided by Real-Time Obligation

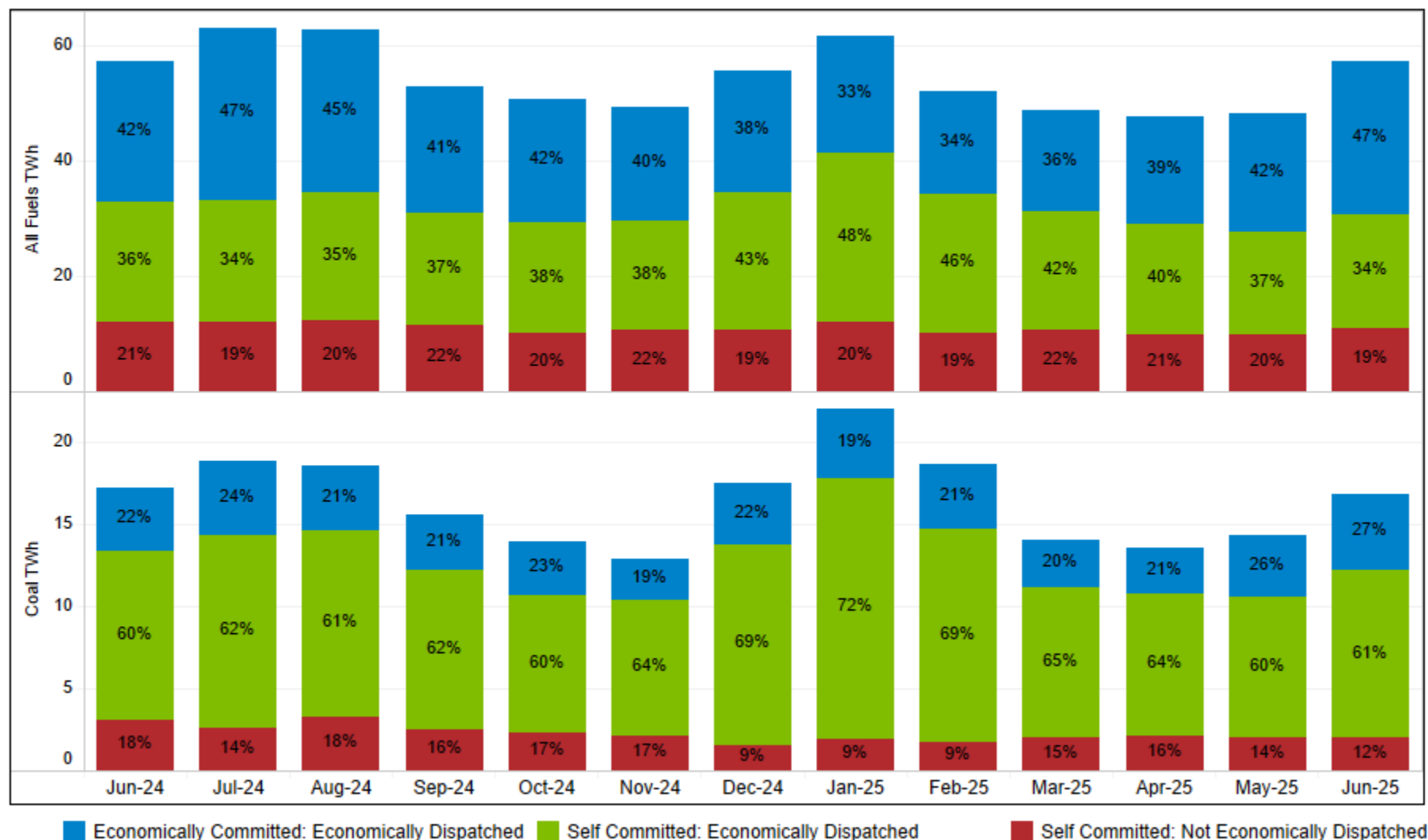
Self Committed and Economically Dispatched Energy - June 2025



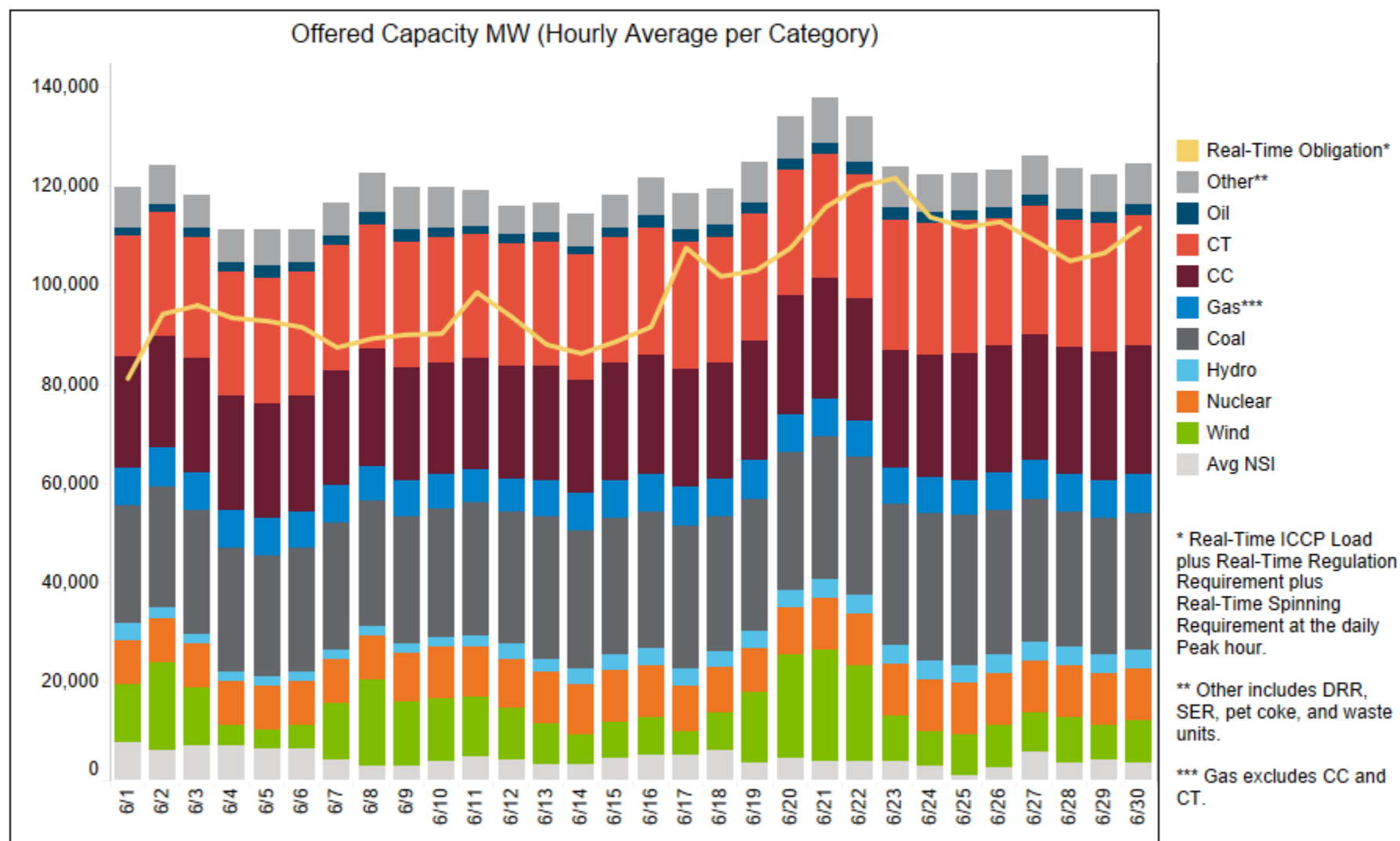
	All Fuels		Coal		Gas	
	TWh	%	TWh	%	TWh	%
Economically Committed: Economically Dispatched	26.8	47%	4.6	27%	17.8	75%
Self Committed: Economically Dispatched	19.8	34%	10.2	61%	4.9	21%
Self Committed: Not Economically Dispatched	10.9	19%	2.0	12%	1.0	4%
Grand Total	57.5	100%	16.8	100%	23.7	100%

	Economically Committed: Economically Dispatched	Generation committed by MISO and dispatched on economic offers.
	Self Committed: Economically Dispatched	Generation that is self-committed, but Resource Owners allow MISO to dispatch economically after the self-schedule portion of their resource offer is satisfied. Self-commitments can be used to manage local reliability, operational constraints, and fuel contract constraints.
	Self Committed: Not Economically Dispatched	Energy from self-committed generation produced at its minimum level or is block-loaded and cannot be dispatched. Block Loaded energy is not necessarily uneconomic, but MISO has no ability to dispatch it based on economics.

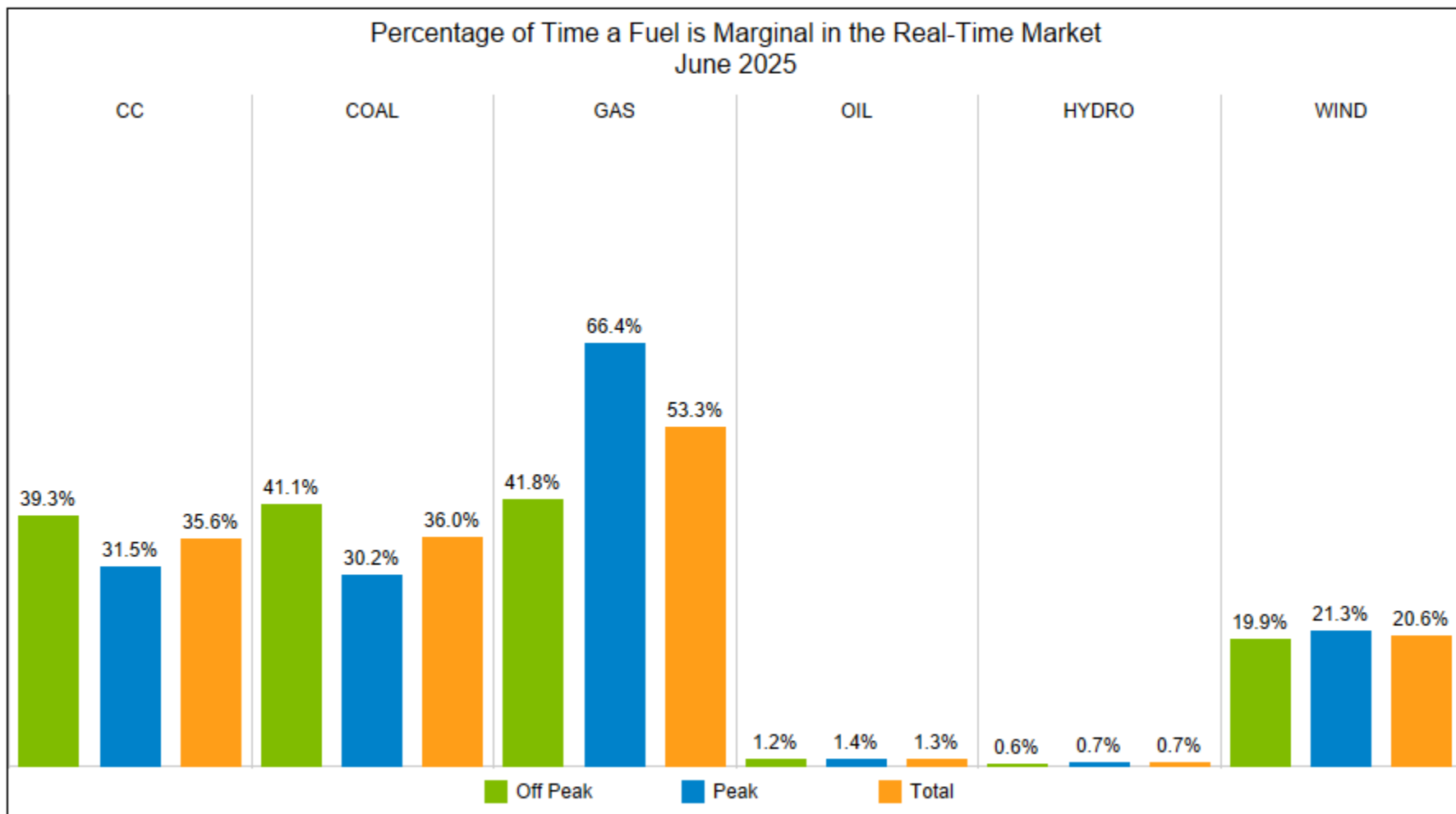
Monthly Trend - Self Committed and Economically Dispatched Energy



Offered Capacity and Real-Time Peak Load Obligation

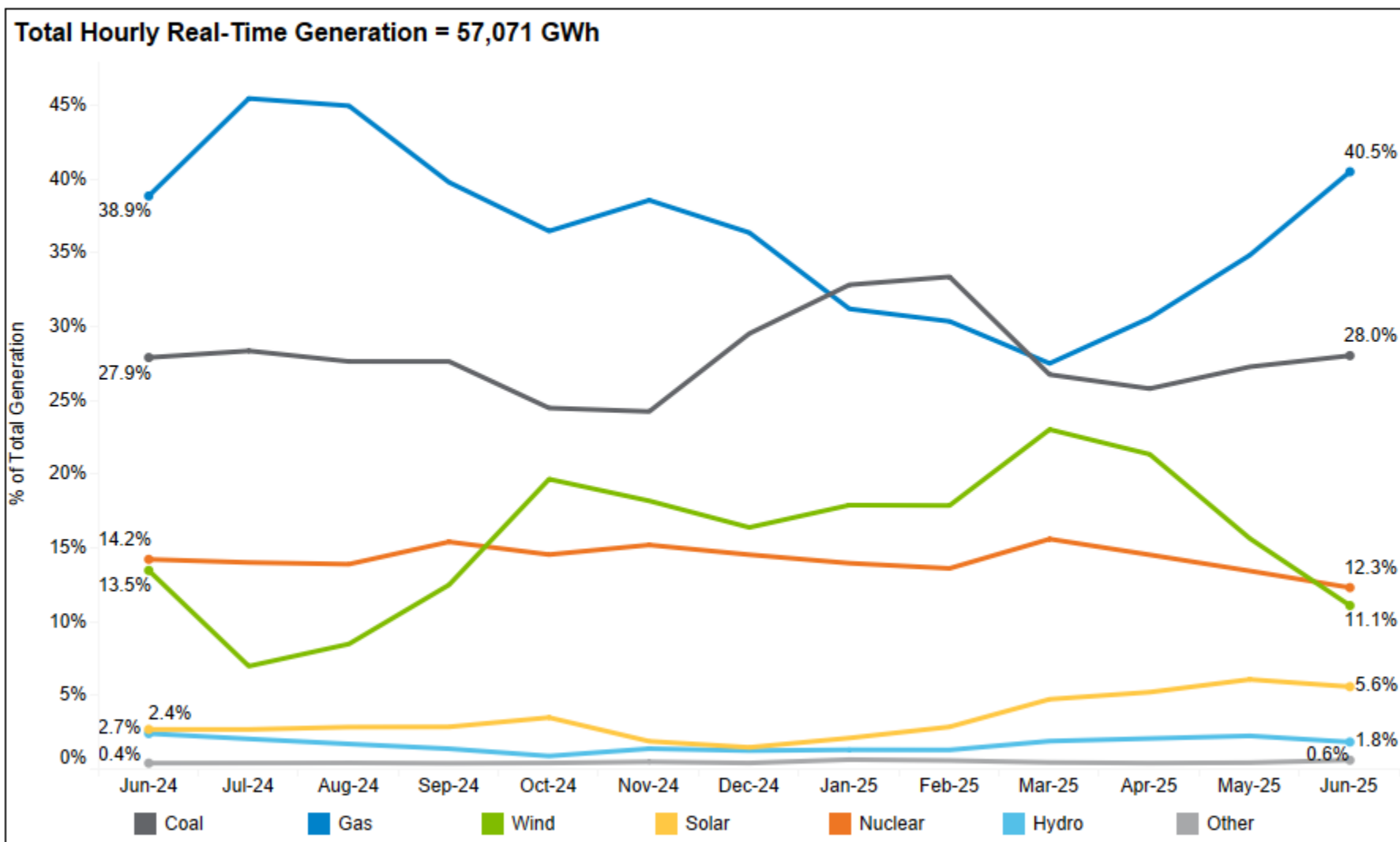


Marginal Fuel



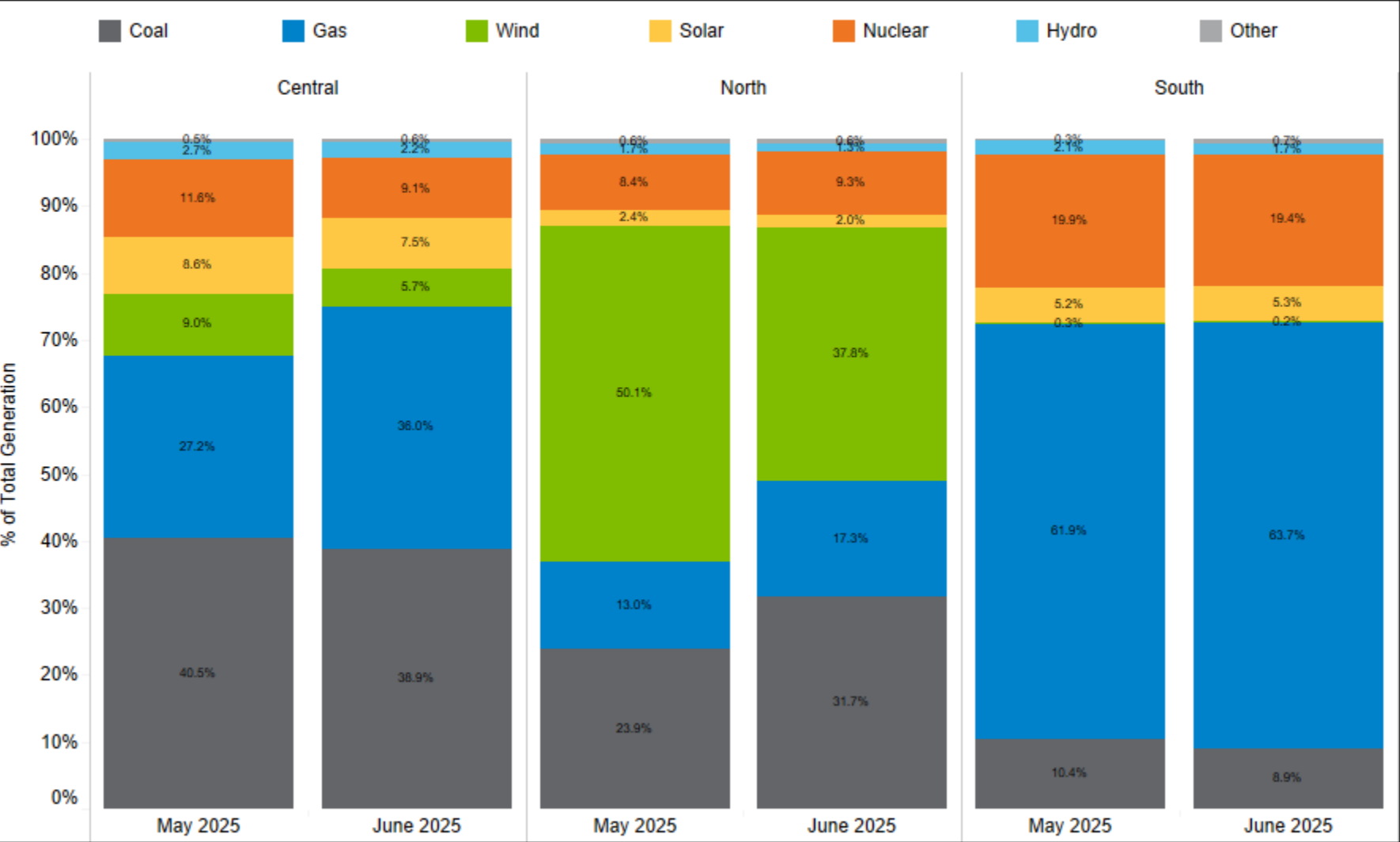
Note: Binding transmission constraints can produce instances where more than one unit is marginal in the system. Consequently, more than one fuel may be on the margin; and since each marginal unit is included in the analysis, the percentage may sum to more than 100%.

Real-Time Generation Fuel Mix



Based on hourly unit level state estimator data
 Other includes: Battery, Oil, Pet Coke, Waste and Other fuels
 Source: MISO Market and Operations Analytics Department

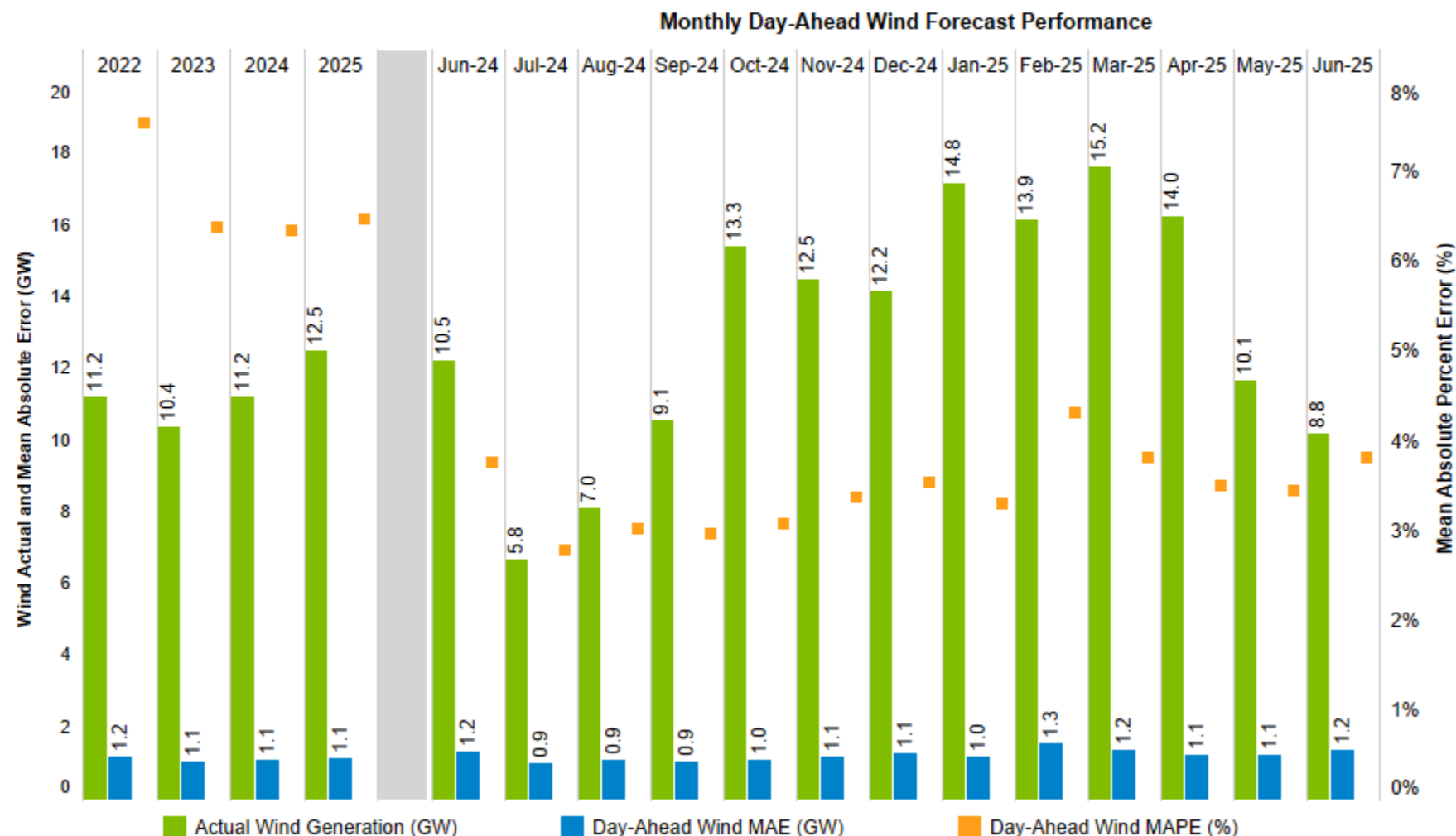
Real-Time Generation Fuel Mix by Region



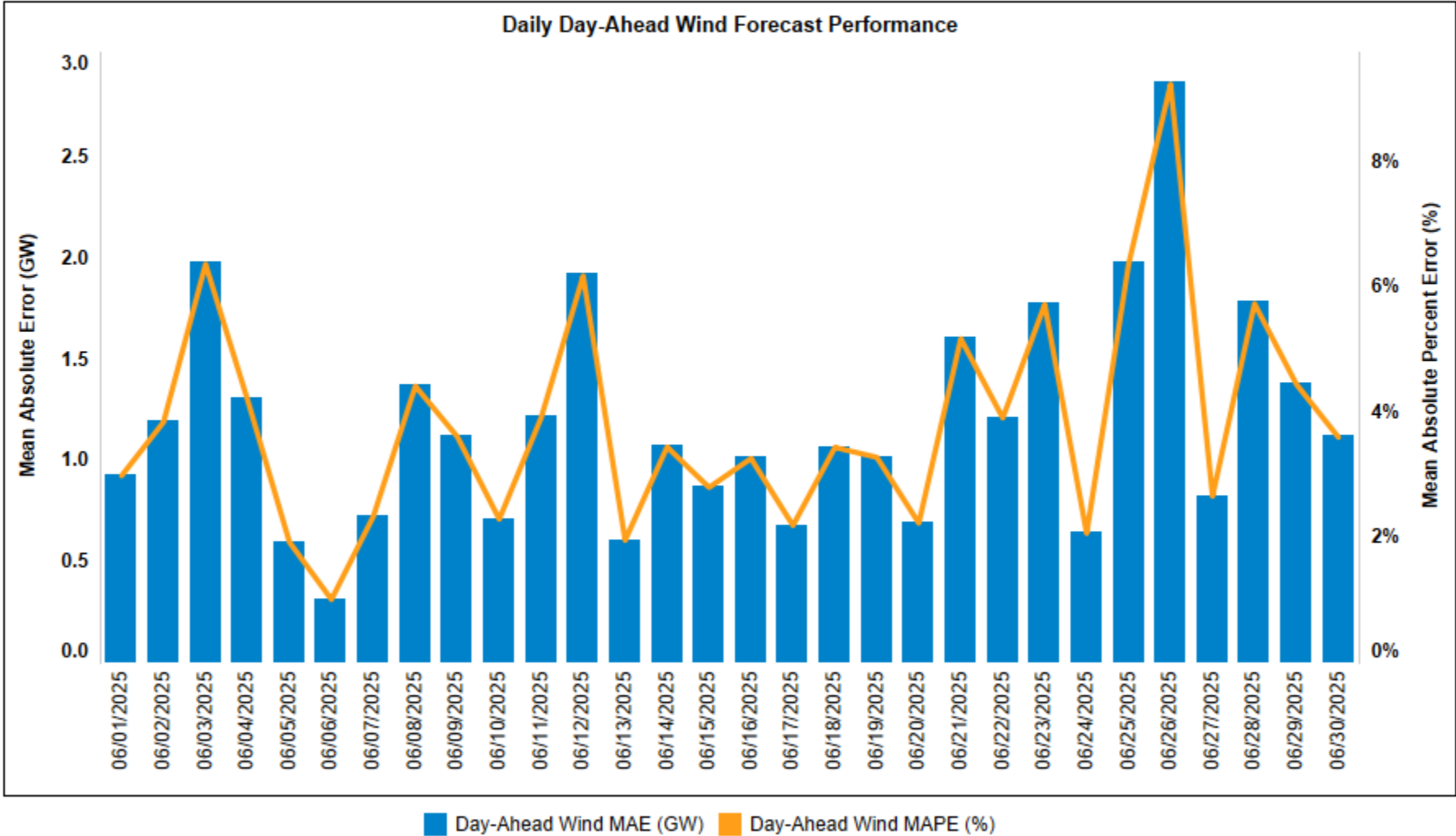
Based on hourly unit level state estimator data
Other includes: Battery, Oil, Pet Coke, Waste and Other fuels
Source: MISO Market and Operations Analytics Department

Monthly Day-Ahead Wind Forecast Performance: Mean Absolute Error (MAE) and Mean Absolute Percent Error (MAPE)

K



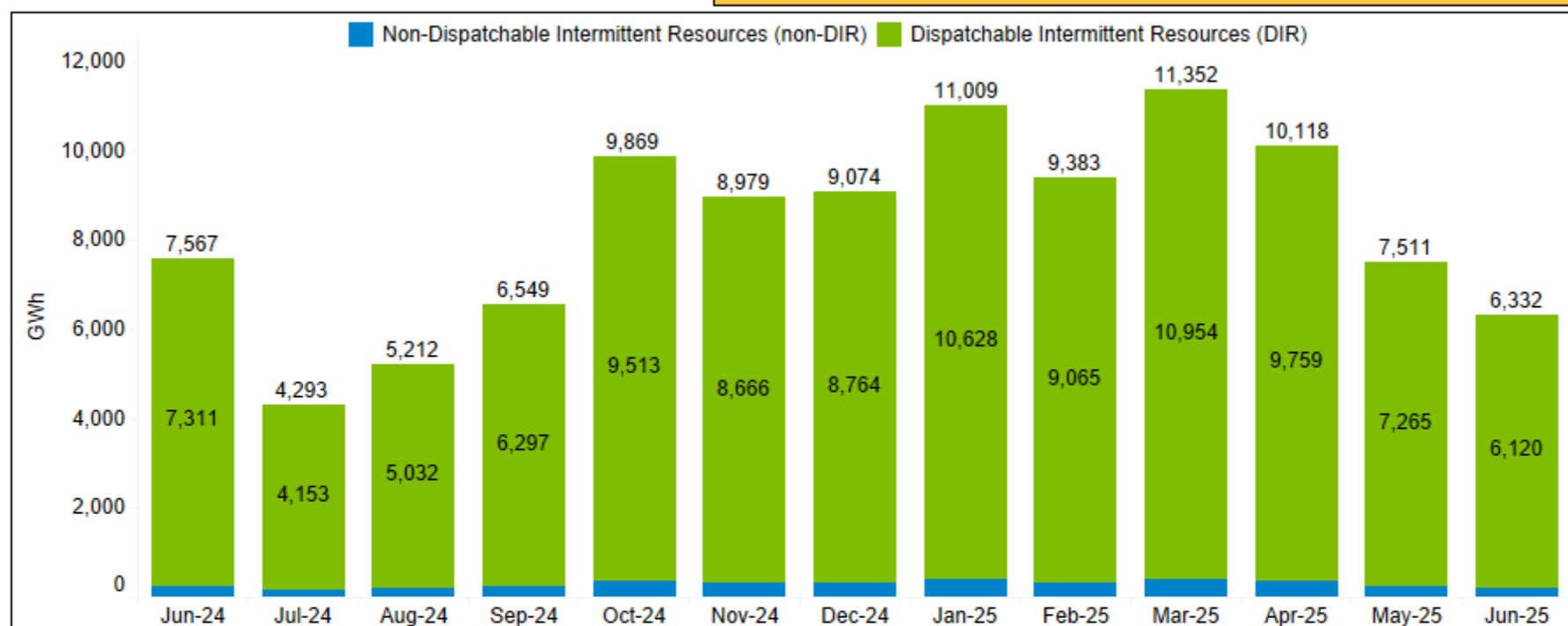
Daily Day-Ahead Wind Forecast Performance: Mean Absolute Error (MAE) and Mean Absolute Percent Error (MAPE)



Monthly Wind Energy Generation

As of 06/04/2025

Registered Wind Capacity = 31,650 MW; Inservice Wind Capacity = 31,315 MW
Registered DIR Capacity = 30,122 MW; Inservice DIR Capacity = 29,787 MW



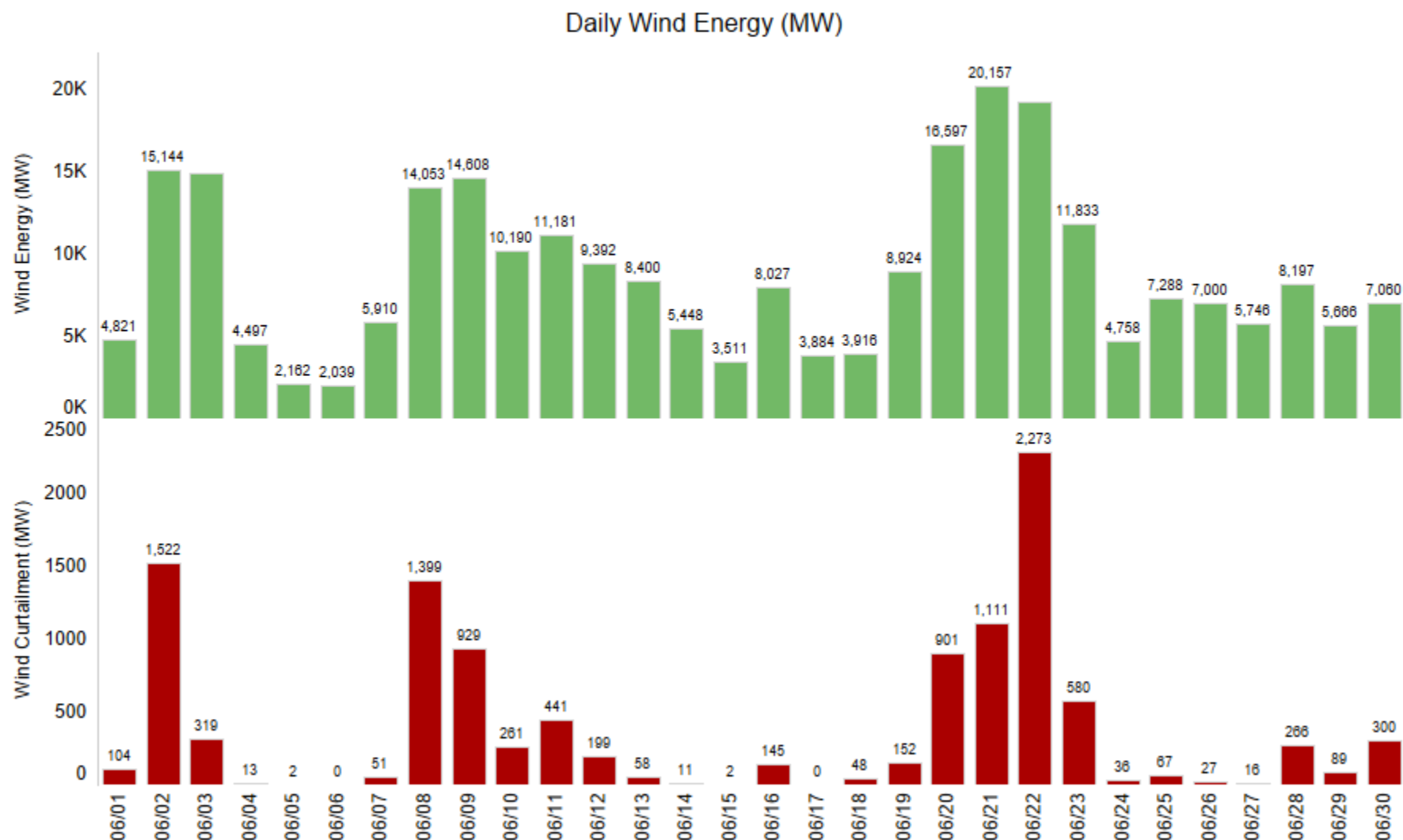
	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25
Peak Wind Date and Hour Ending	6/6 17	7/1 23	8/6 4	9/12 24	10/30 2	11/20 16	12/4 11	1/28 21	2/28 22	3/23 15	4/28 19	5/16 21	6/21 15
Peak hourly wind output (MW)	21,341	18,465	15,418	16,944	22,683	21,272	24,044	25,218	24,646	24,172	23,582	22,803	21,086
Peak wind output as % of MISO load in that hour	24.1%	24.0%	21.2%	24.2%	36.1%	29.0%	28.7%	31.2%	34.1%	34.6%	28.6%	28.6%	19.3%
Wind Energy as a percent of MISO Energy	13.7%	7.3%	8.8%	12.8%	19.9%	18.4%	16.3%	18.2%	18.1%	23.2%	21.5%	15.6%	11.3%
DIR dispatch below Max as % of avail. DIR	3.0%	2.1%	2.7%	4.9%	4.0%	3.4%	2.3%	3.3%	2.0%	3.1%	4.3%	3.3%	3.3%

*Hourly State Estimator data

Source: MISO Market and Operations Analytics Department

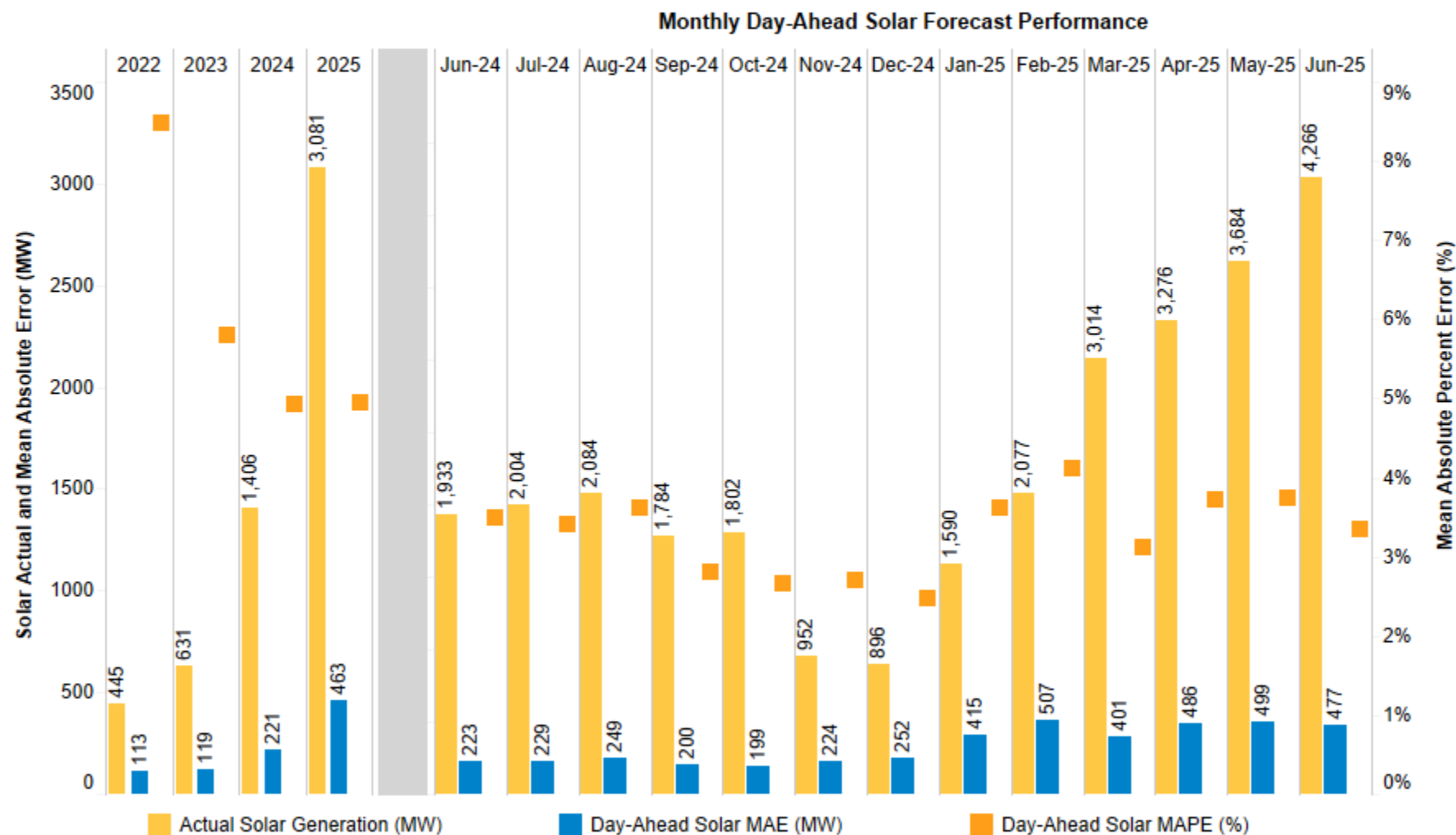


Daily Average Wind Energy and Curtailment

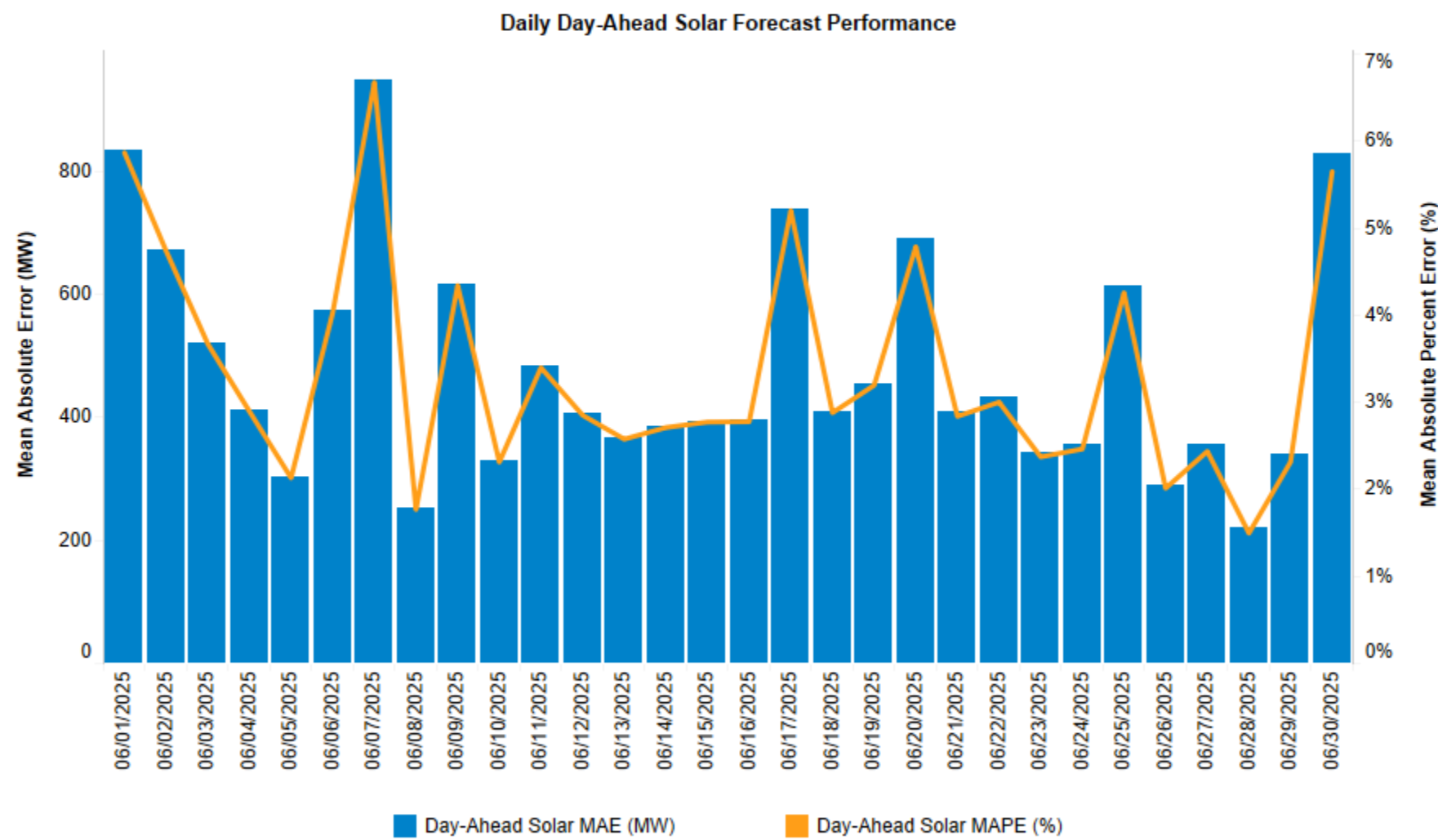


Source: MISO Market and Operations Analytics Department

Monthly Day-Ahead Solar Forecast Performance: Mean Absolute Error (MAE) and Mean Absolute Percent Error (MAPE)



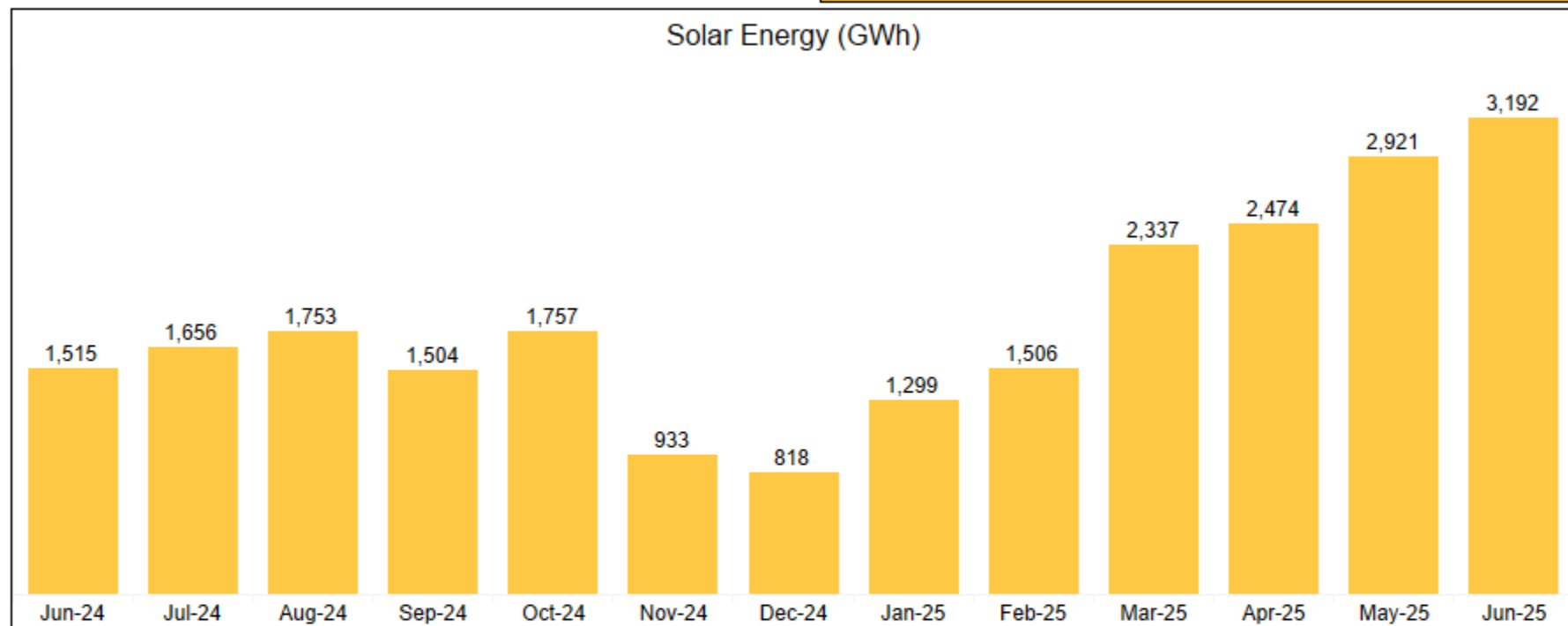
Daily Day-Ahead Solar Forecast Performance: Mean Absolute Error (MAE) and Mean Absolute Percent Error (MAPE)



Monthly Solar Energy

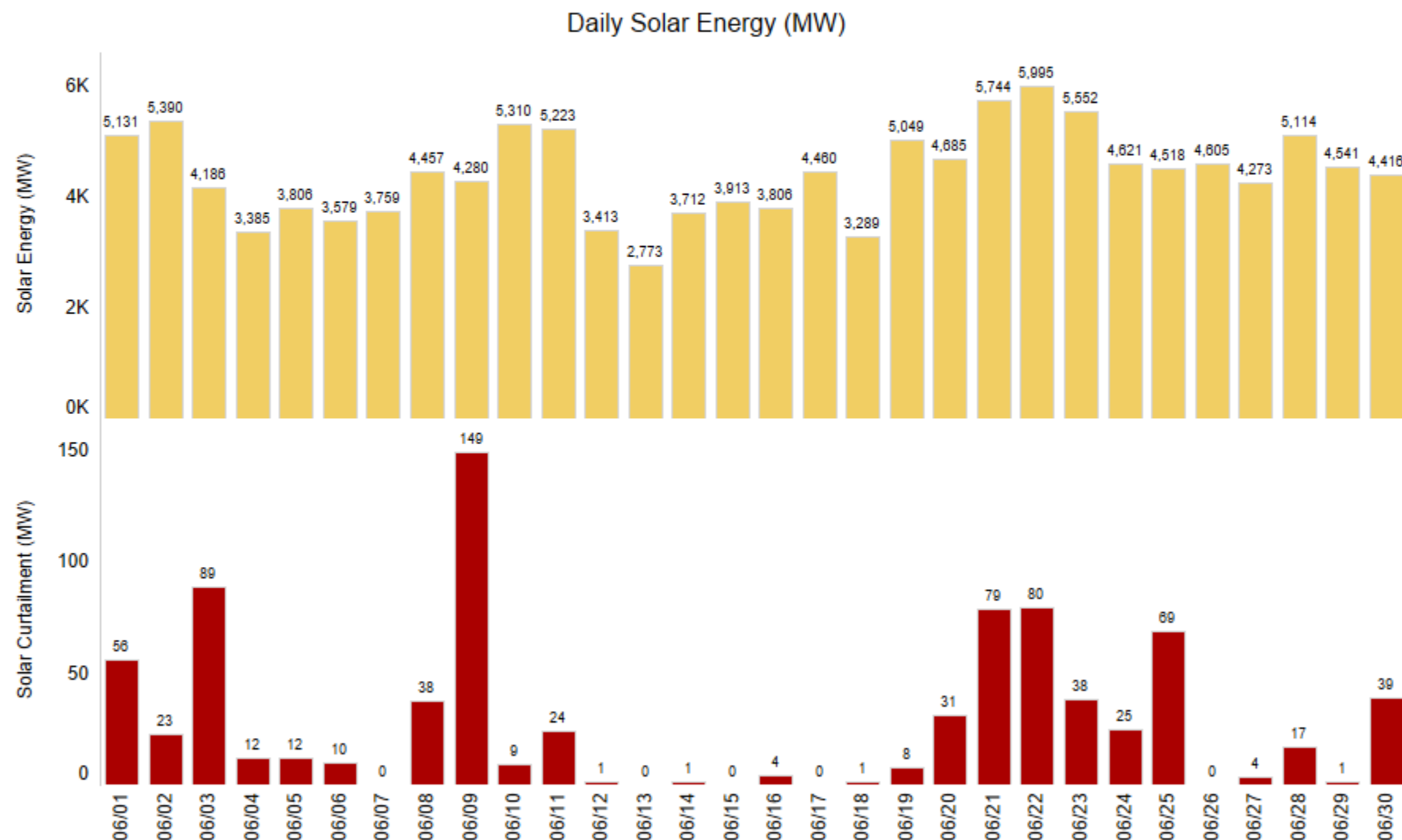
As of 06/04/2025
 Registered Solar Capacity = 19,131 MW; Inservice Solar Capacity = 14,112 MW
 Registered DIR Capacity = 18,959 MW; Inservice DIR Capacity = 13,940 MW

Solar Energy (GWh)

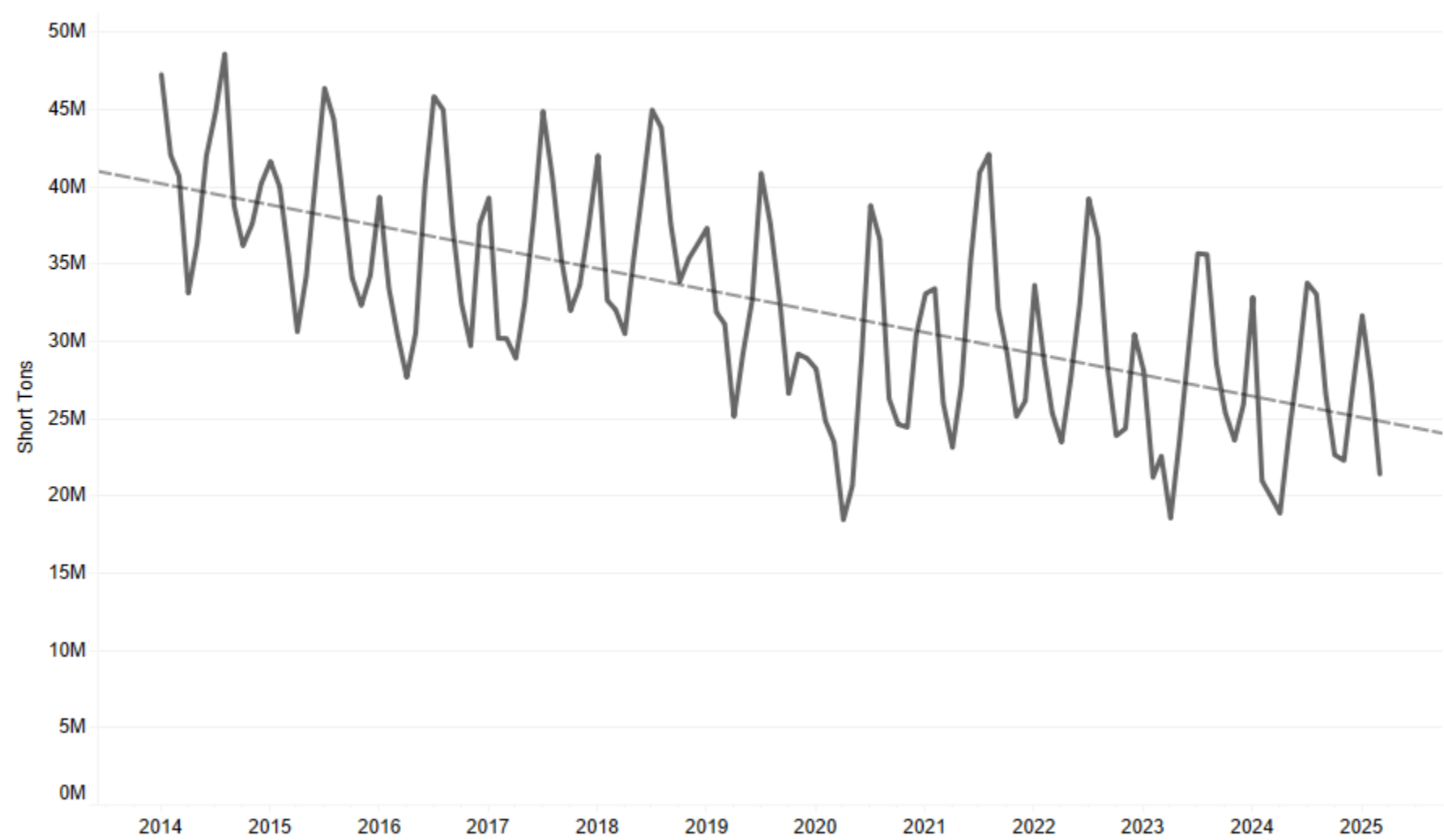


Peak Solar Date and Hour Ending	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25
	6/14 11	7/13 12	8/22 12	9/26 12	10/16 16	11/12 16	12/21 12	1/20 12	2/21 12	3/22 15	4/16 14	5/31 13	6/22 11
Peak Hour Solar Output (MW)	6,016	6,168	6,835	7,054	7,919	6,813	6,898	8,308	11,360	12,061	12,342	13,366	12,872
Peak Solar Output as a % of MISO Load in that hour	6.9%	6.5%	8.3%	9.1%	11.5%	9.6%	8.7%	8.4%	12.4%	18.8%	18.0%	19.2%	12.9%
Solar Energy as a % of MISO Energy	3.4%	3.2%	3.8%	3.5%	4.7%	2.6%	2.0%	2.6%	3.5%	6.0%	5.4%	6.0%	6.0%
DIR Dispatch below MAX as a % of avail. DIR	-0.1%	-0.5%	-0.5%	0.4%	-0.3%	-0.6%	-3.1%	-1.9%	0.1%	1.1%	0.5%	-0.1%	-0.1%

Daily Average Solar Energy and Curtailment

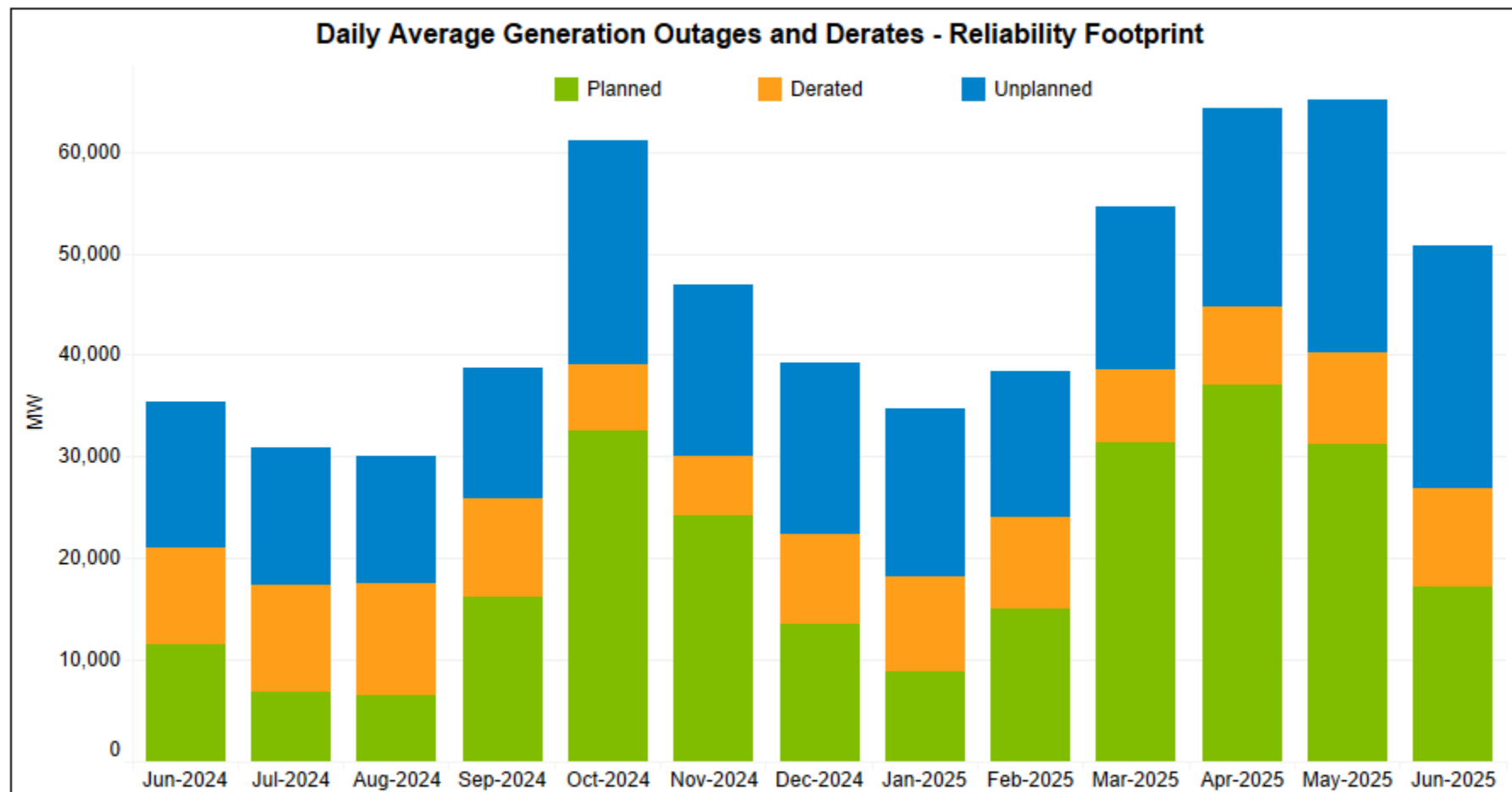


Carbon Emissions



Data Source: EPA emissions through March 2025 and EPA EIA-860 2023
Emissions generated from MISO generators and does not account for volume of imports or exports
One Short Ton = 2000 lbs

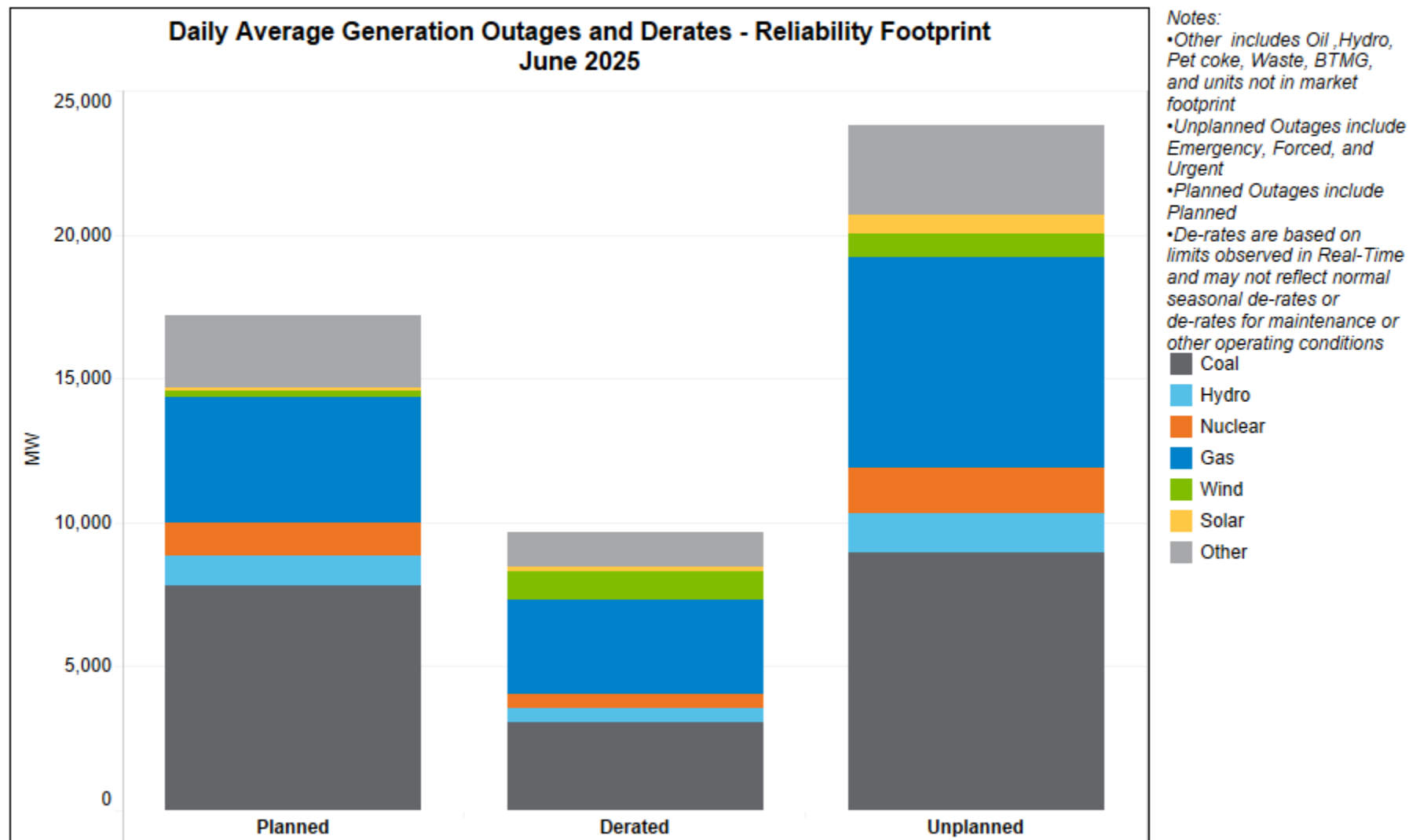
Generation Outages and Derates



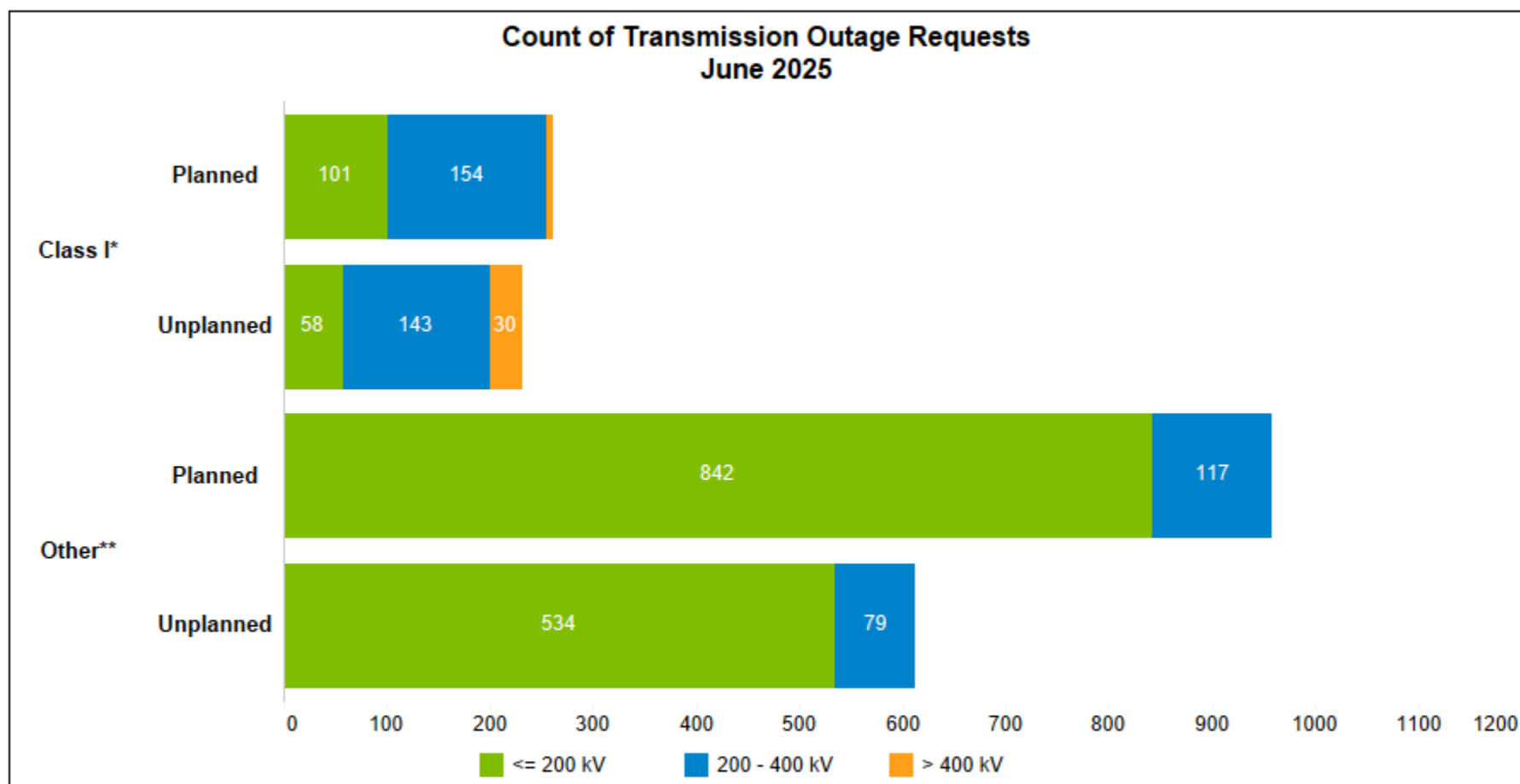
Notes:

- Unplanned Outages include Emergency, Forced, and Urgent
- Planned Outages include Planned
- De-rates are based on limits observed in Real-Time and may not reflect normal seasonal de-rates or de-rates for maintenance or other operating conditions

Generation Outages by Fuel



Transmission Outages



Notes:

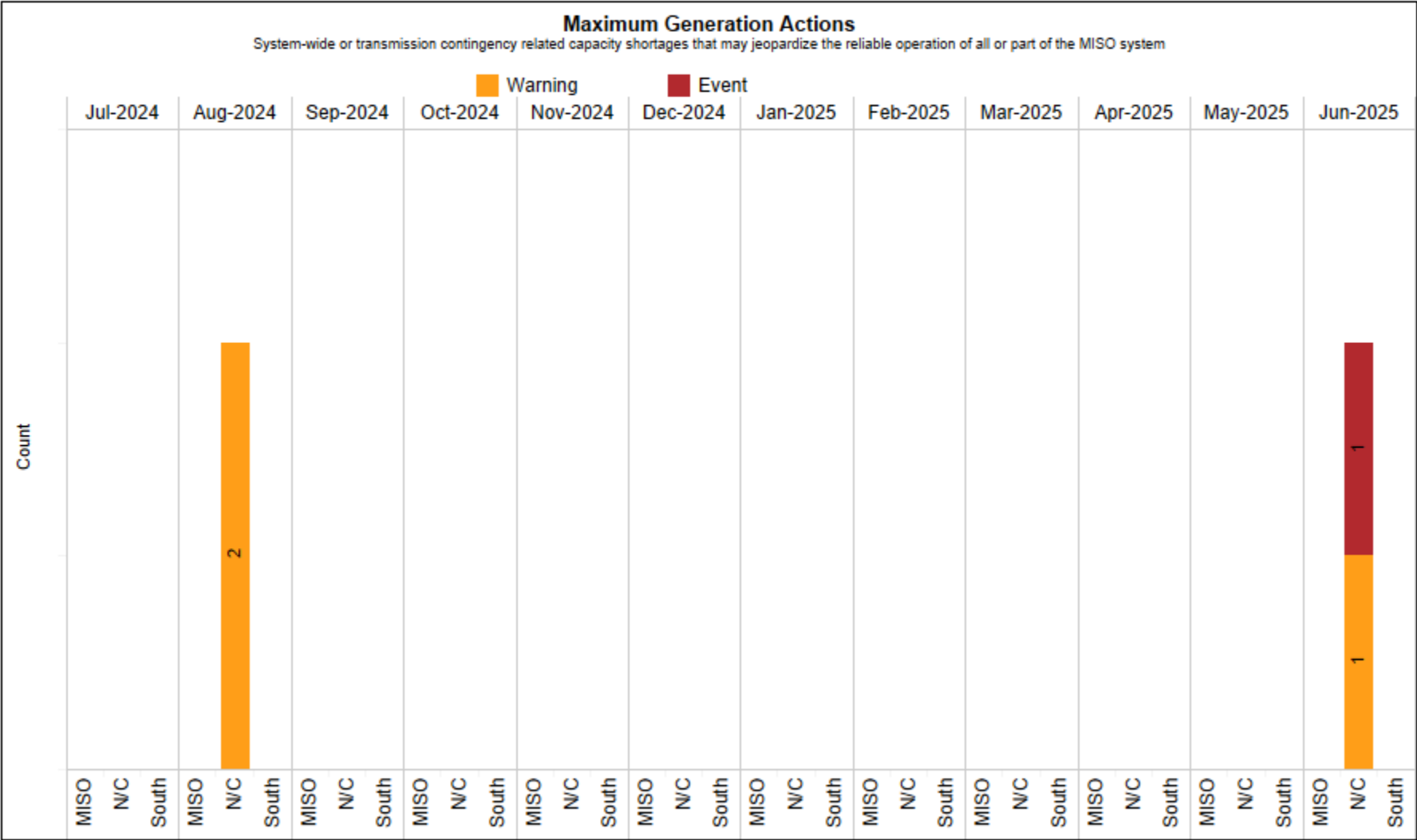
- Class 1 is any facility which has a reliability or market impact on transmission system operations
- Other is any facility which does NOT have a reliability or market impact on transmission system operations
- Unplanned Outages include Emergency, Forced, Discretionary and Urgent
- Planned Outages include Planned, Opportunity

MISO Inadvertent Balance

Month/Year	Net	On-Peak	Off-Peak
6/1/2024	-21,123	-10,382	-10,741
7/1/2024	-33,949	-12,863	-21,086
8/1/2024	-39,602	-15,448	-24,154
9/1/2024	-79,156	-36,769	-42,387
10/1/2024	-37,833	-17,446	-20,387
11/1/2024	-5,440	-2,237	-3,203
12/1/2024	-1,006	624	-1,630
1/1/2025	11,913	7,358	4,555
2/1/2025			
3/1/2025			
4/1/2025			
5/1/2025			
6/1/2025			
Running Total from 2009	-95,937	-88,521	-7,416

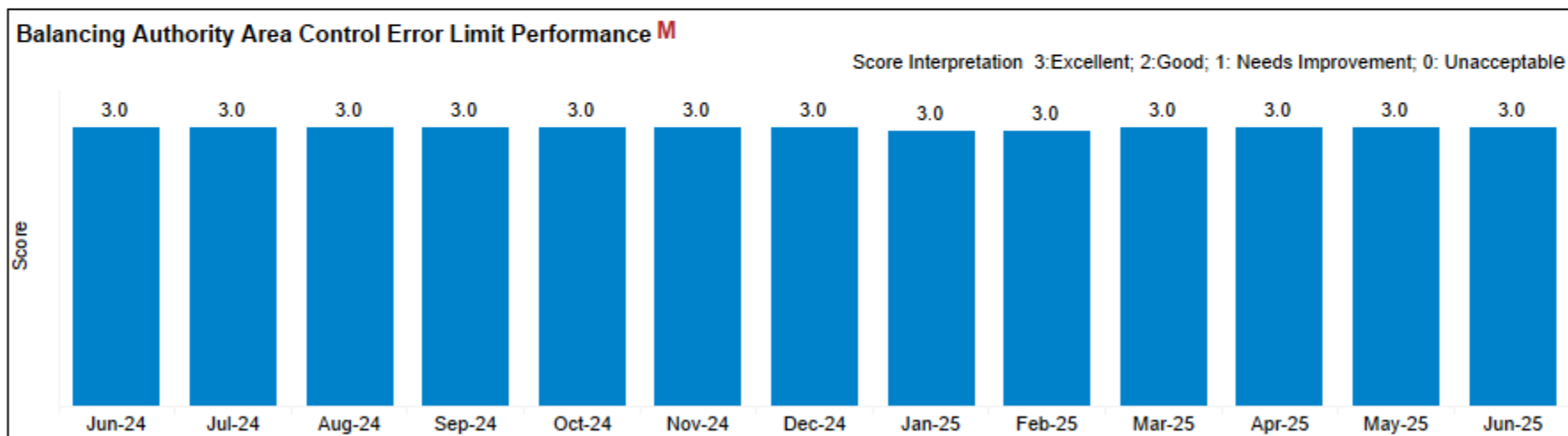
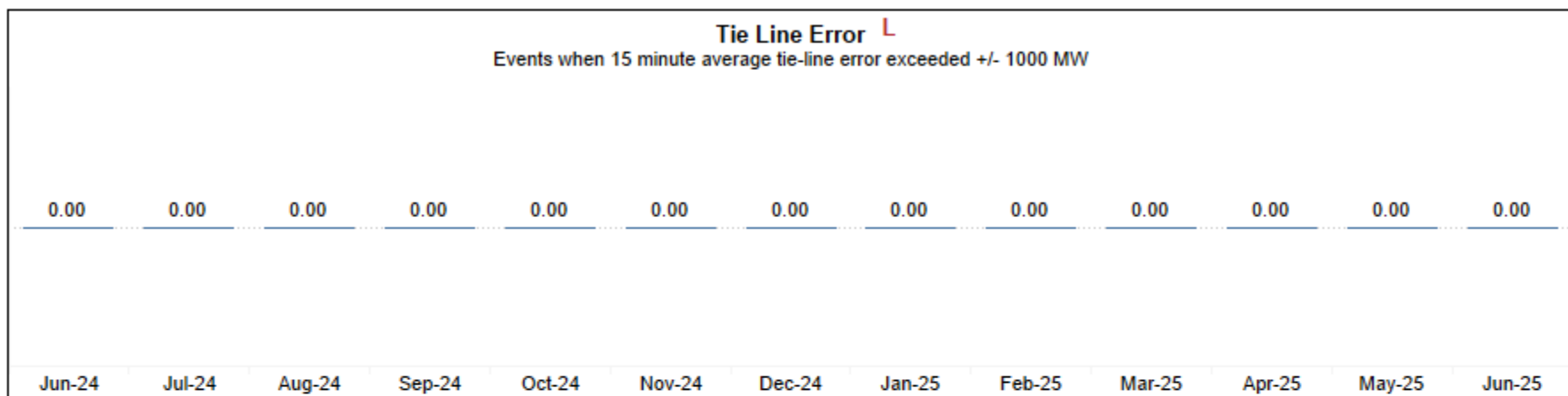
Source: NERC Tool (As of May 10, 2025)

Generation Notifications



* Alerts – forecasting specific emergency situations in a future time-frame
* Warnings – experiencing initial stages of an emergency situation and taking action
* Events – experiencing an emergency situation and taking action

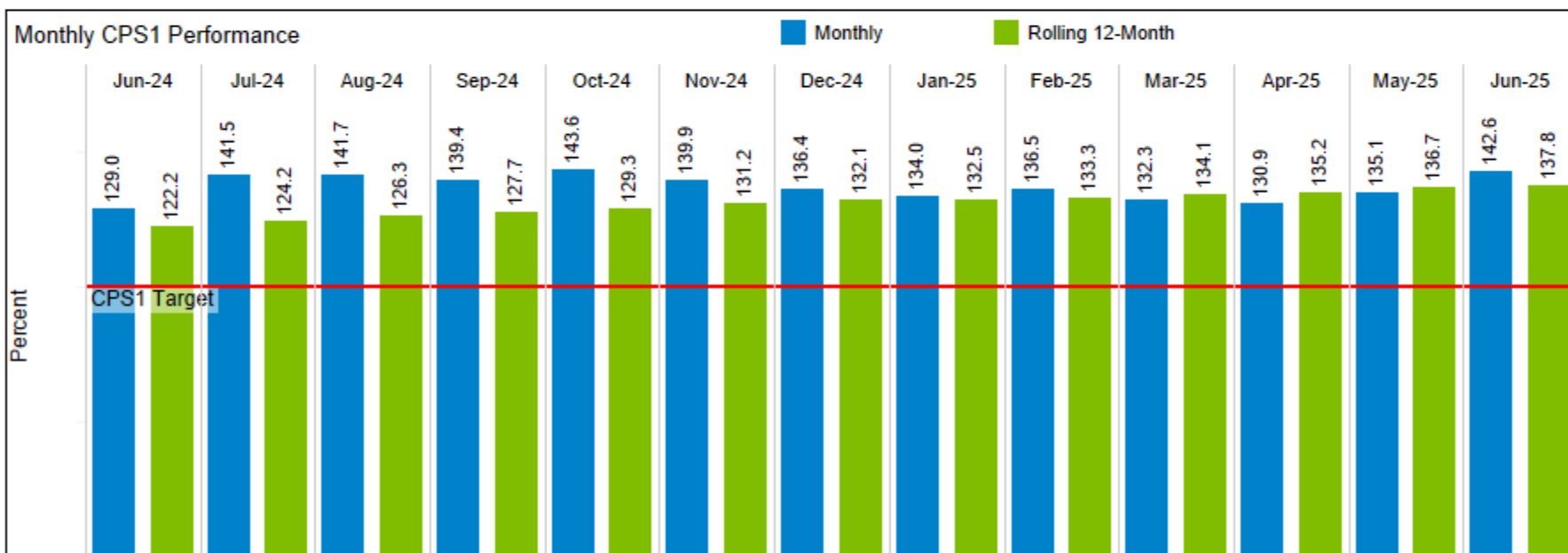
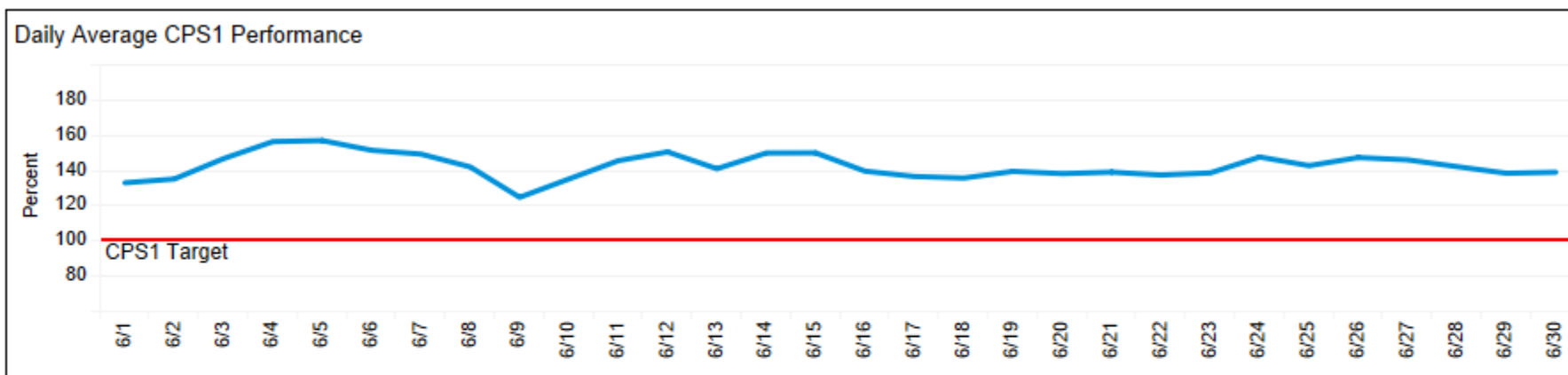
Tie Line and BAAL Performance



The Balancing Authority Area Control Error Limit (BAAL) measures control performance over the short-term. Exceeding BAAL for a continuous time period greater than 30 minutes constitutes a non-compliant event. The daily MISO BAAL performance rating is the lowest scored incident of the day.

CPS1 Performance

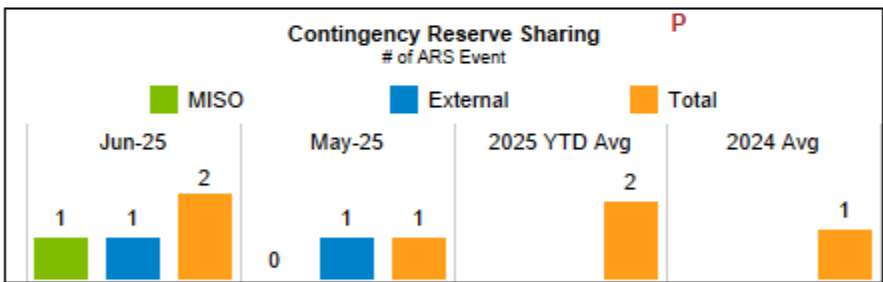
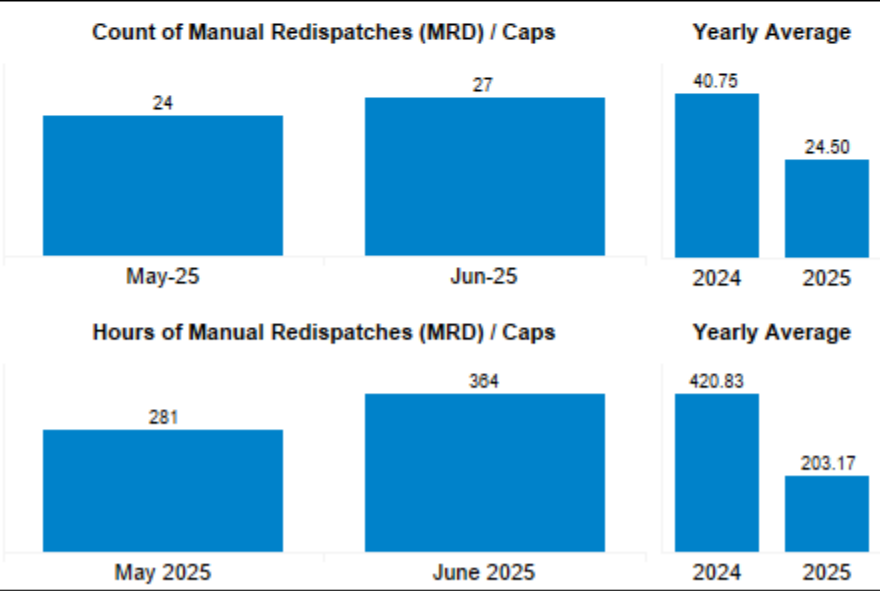
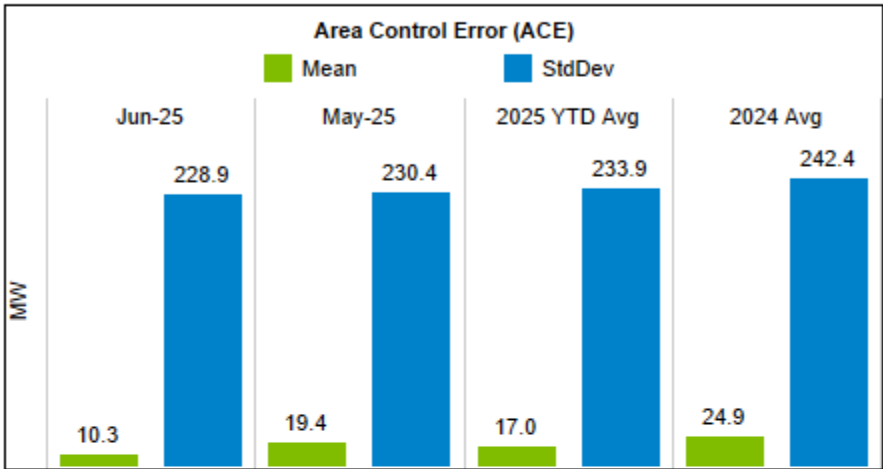
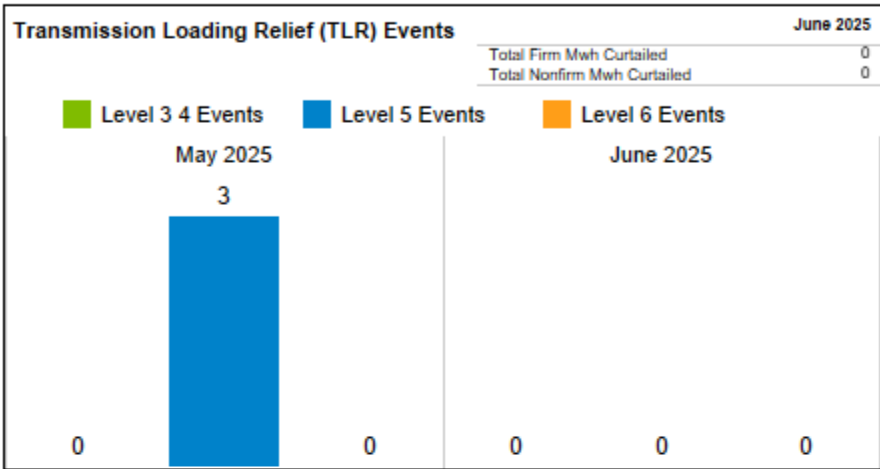
N



Per NERC Standard BAL-001-0 and MISO OP-044, the MISO will monitor CPS 1 performance and implement actions to ensure the MISO's rolling 12-month CPS 1 performance exceeds 100%
Source: MISO Real-Time Operations Department



Reliability — Other Metrics



MISO deployed Contingency Reserves **

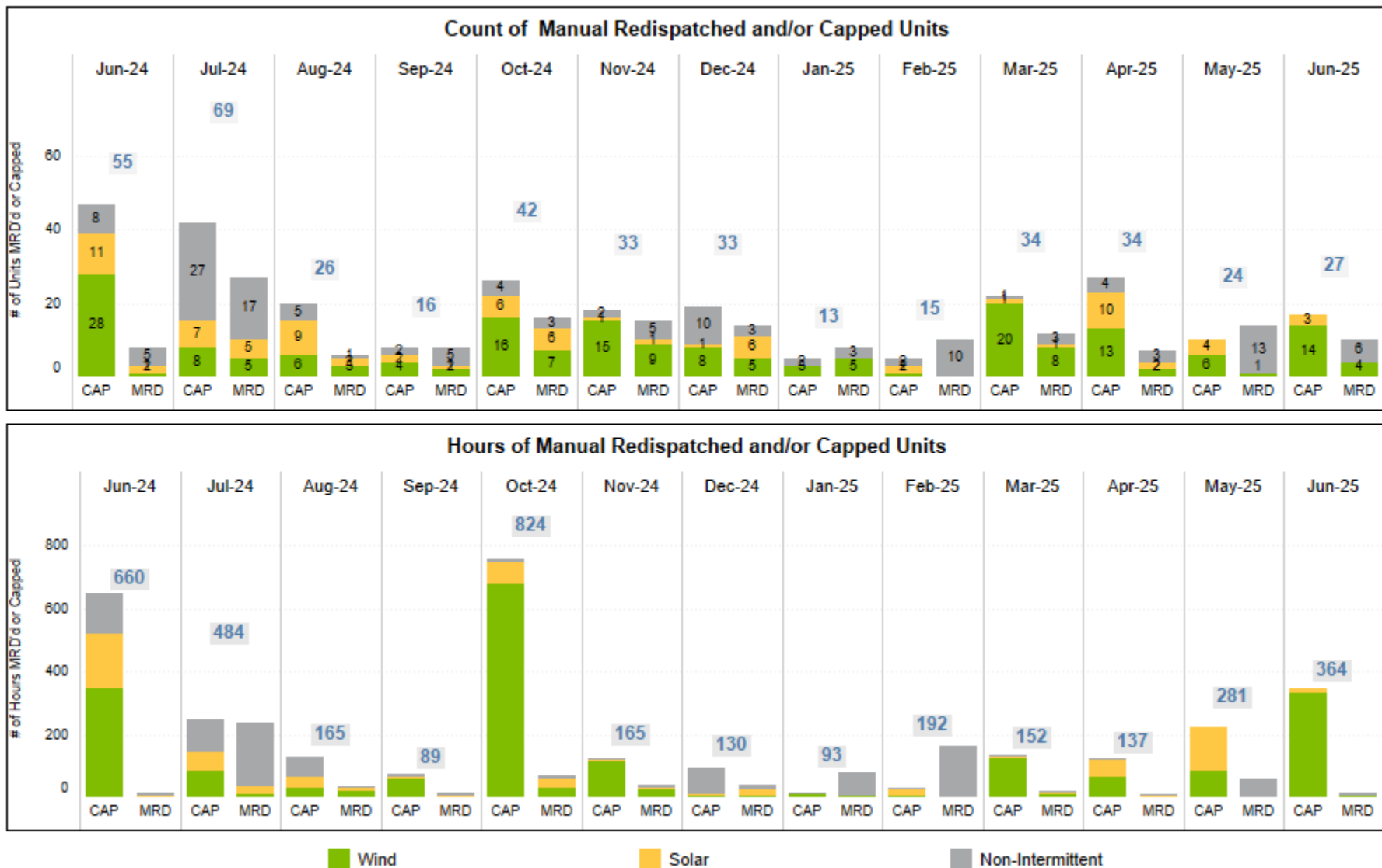
Date	HE	Deployment Type	MW
6/1/2025	19	OFFLINE	79
		ONLINE	1,227
6/17/2025	5	OFFLINE	338
		ONLINE	961
5/20/2025	9	ONLINE	512

Source: MISO Real-Time Operations Department

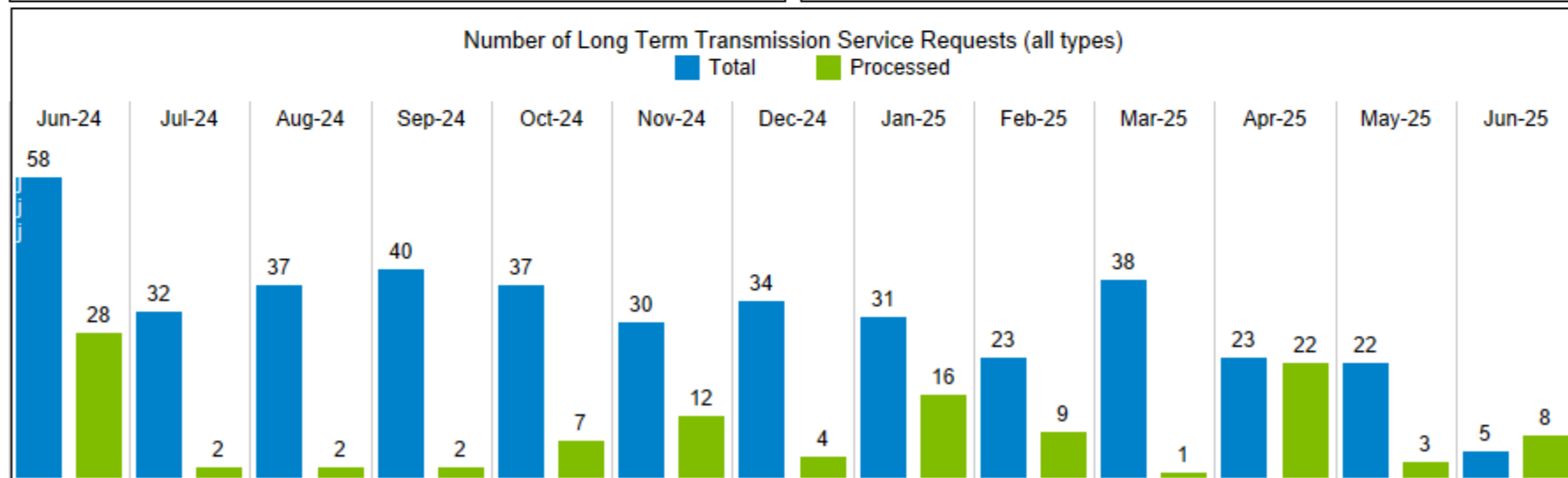
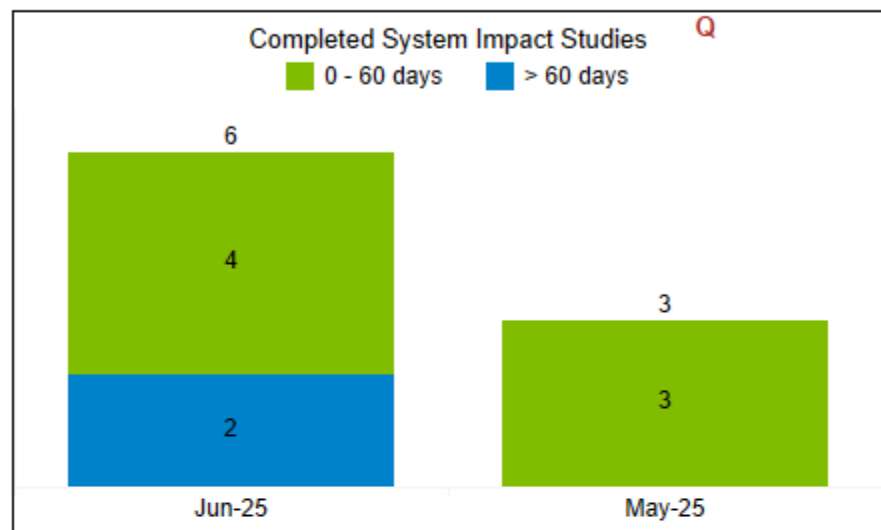
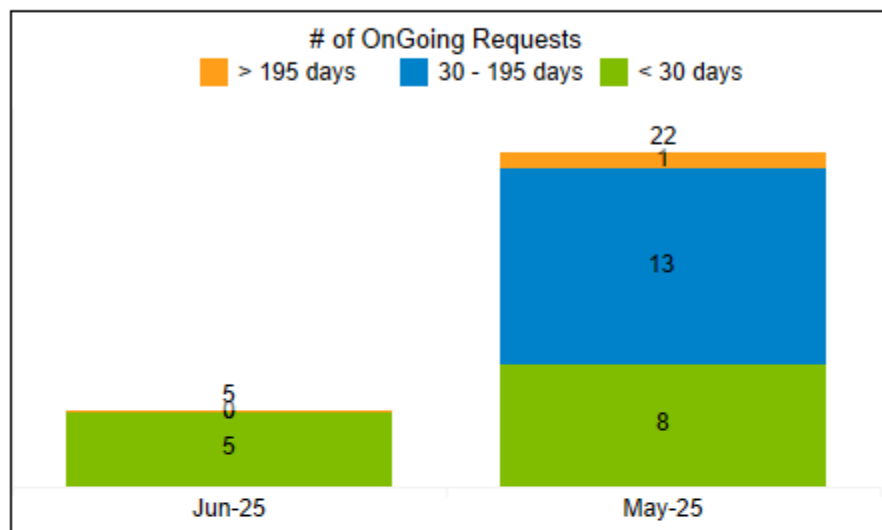
53*Historical Contingency Deployment data located in Related Documents at <https://cdn.misoenergy.org/202001-202103%20Additional%20Information%20Historical%20Contingency%20Deployment%20Data548321.pdf>



Operator Actions - Manual Redispatch and Caps

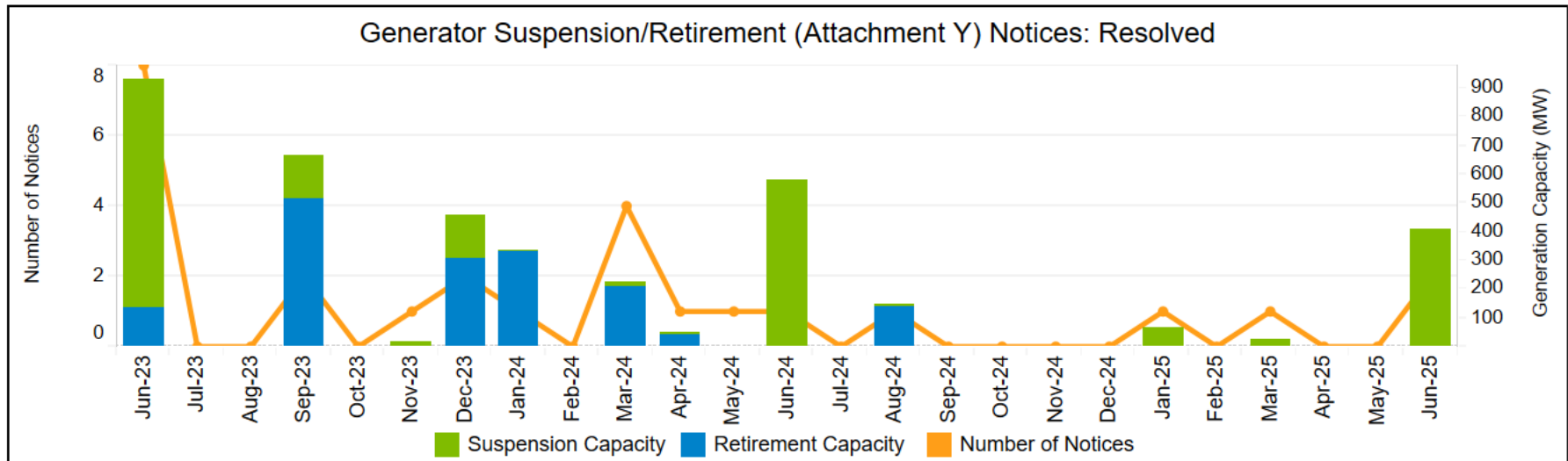
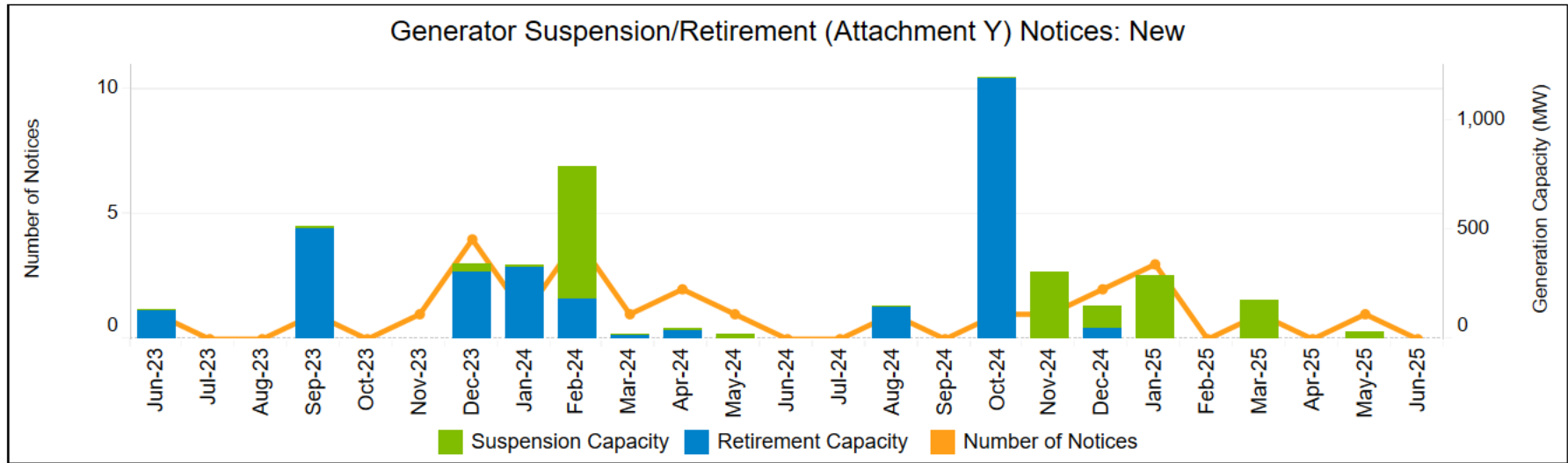


Transmission Service Request

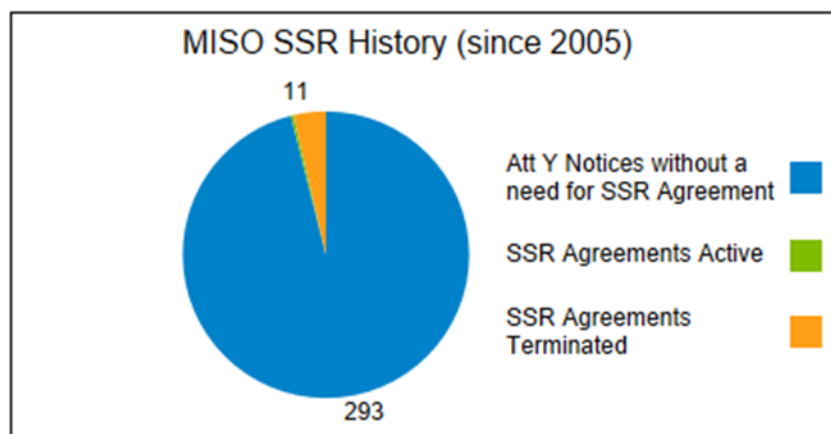
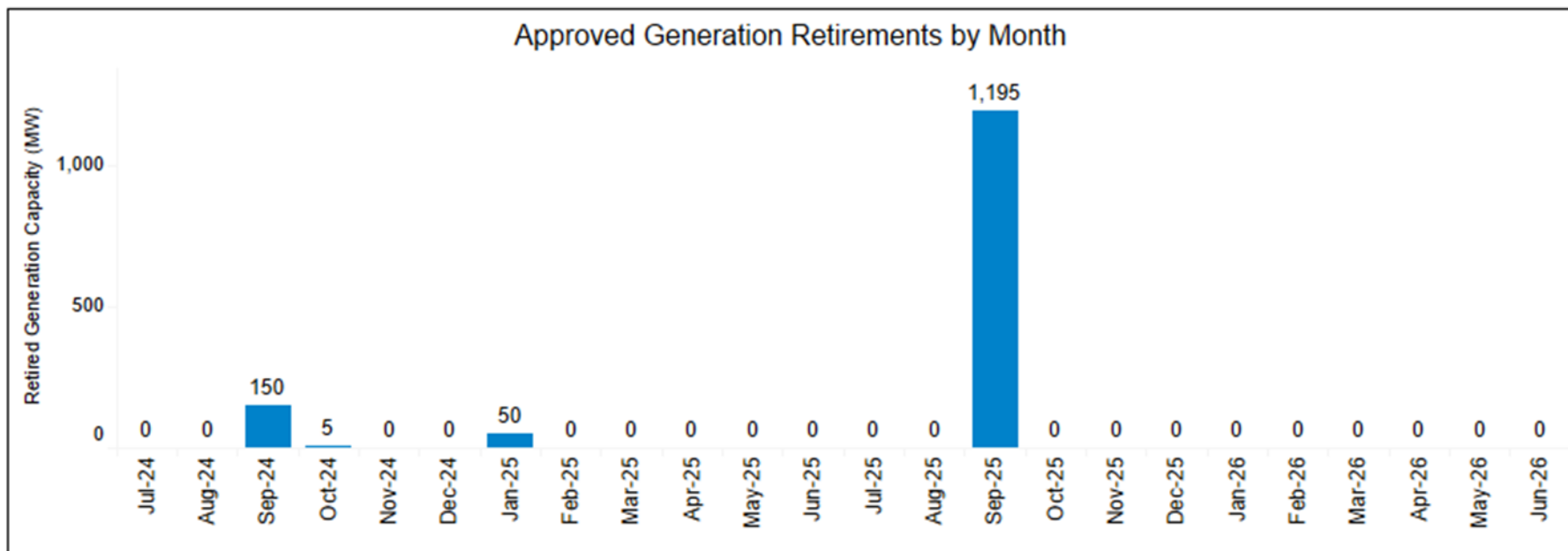


Source: MISO Resource Utilization

Generator Suspension/Retirement - New and Resolved

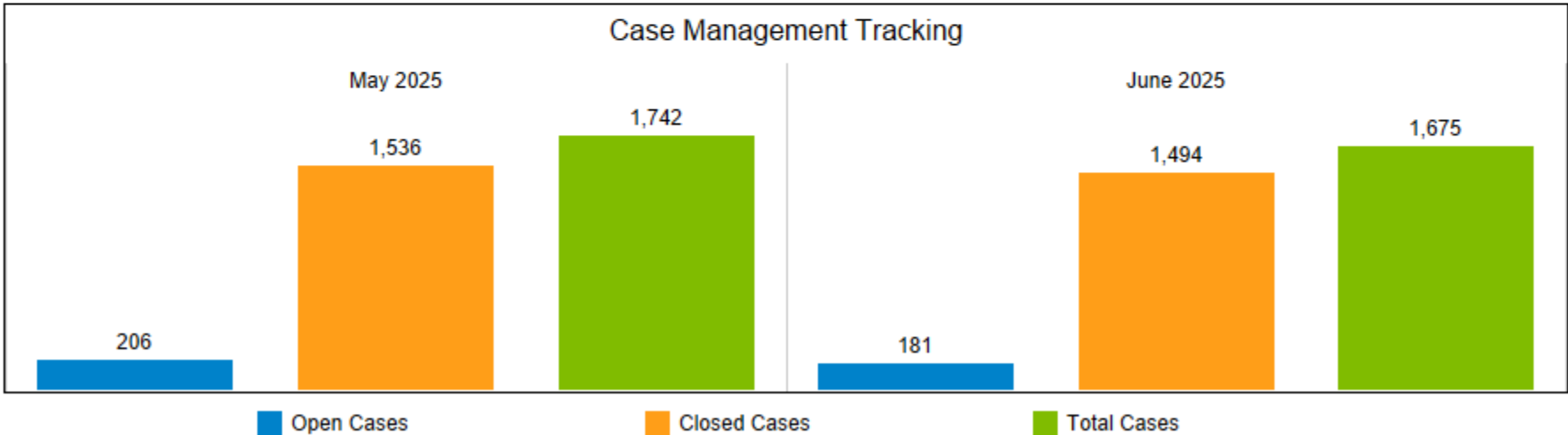
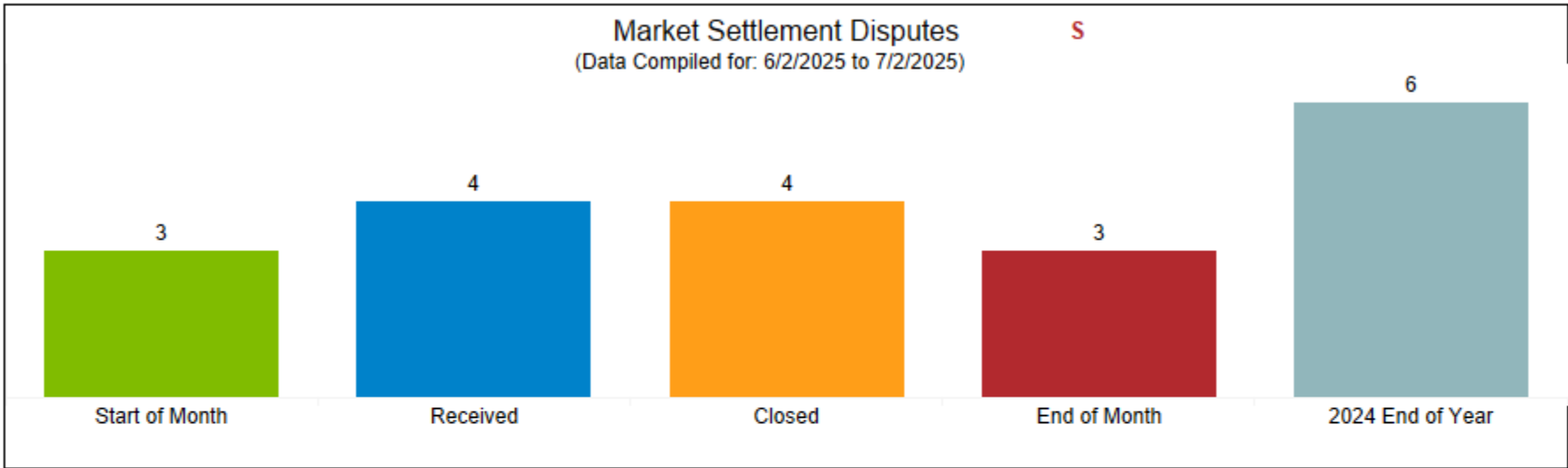


Generator Suspension/Retirement - Overall



Source - MISO Transmission Planning Department

Settlements/Client Services and Readiness



MISO has set an even higher standard for its System Availability metrics in 2025, and while January and February had no downtime, a critical incident occurred in March that impacted STI

January - April 2025

Short-Term Incentive Metrics	JAN 25	FEB 25	MAR 25	APR 25	Trend *	YTD	Threshold Target Excellent
Critical Systems Availability (Downtime in Hours)	0.0	0.0	1.5	0.0		1.5	4 Hours 3 Hours 2 Hours
Number of Critical System Incidents Exceeding 30 Minutes	0	0	1	0.0		1	2 1 0
Other Availability Metrics	JAN 25	FEB 25	MAR 25	APR 25	Trend *	Monthly Target	
ICCP** (Availability %)	100	100	100	100		99.5	
Customer Facing Applications – Portals (Availability Index)	10	10	10	10		10 of 10	
Markets (Availability Index)	4	4	4	4		4 of 4	
Reliability Targets (Availability Index)	3	3	3	3		3 of 3	

*Trend lines represent quarter-over-quarter performance

**ICCP = Inter-Control Center Communications Protocol

2025 Dashboard Metric Criteria (1 of 2)

*New or revised 2025 Metric;

Operational Excellence									
Metric	Chart	Expected	Monitor	Review	Metric	Chart	Expected	Monitor	Review
Percentage Price Deviation*	A	Absolute DA-RT price difference divided by DA LMP <=28.6%	Absolute DA-RT price difference divided by DA LMP is >28.6% but <=34.3%	Absolute DA-RT price difference divided by DA LMP >34.3%	Unit Commitment Efficiency*	H	>=93%		<93%
Monthly Average Gross Virtual Profitability*	B	Within the standard deviation bands (threshold \$0.44/MWh)	Outside the standard deviation bands		Real-Time Obligation fulfilled by Day-Ahead Supply at the Peak Hour	I	>=95%	>=93% but <95%	<93%
FTR Funding	C	Monthly FTR Allocation % is >=92% and YTD FTR Allocation % is >=96%	Not in good status AND Monthly FTR Allocation % is >=87% AND Rolling 12-month FTR Allocation % is >=93%	Not in Good AND not in Monitor status	Day Ahead Wind Generation Forecast Error	K	# of days that the hourly average forecast error exceeds 10% <= 6	# of days that the forecast error exceeds 10% >6 or Forecast error exceeds 15% in = 3 days	# of days that the forecast error exceeds 10% >8 or Forecast error exceeds 15% in > 3 days or Forecast error resulted in declaring 1 Real Time Event
Market Efficiency Metric	D	>= 95%		<95%	Day Ahead Solar Generation Forecast Error	T	# of days that the hourly average forecast error exceeds 10% <= 6	# of days that the forecast error exceeds 10% >6 or Forecast error exceeds 15% in = 3 days	# of days that the forecast error exceeds 10% >8 or Forecast error exceeds 15% in > 3 days or Forecast error resulted in declaring 1 Real Time Event
RSG per MWh to Energy Price*	E	<=0.38%	>0.38% and <=0.46%	>0.46%	Tie Line Error	L	<=1	>1 but <=3	>3
Day Ahead Mid-Term Load Forecast**	F	# of days that forecast error exceeds 3% <=6 AND # days that forecast error exceeds 4% <=4	# of days that forecast error exceeds 3% > 6 OR # days that forecast error exceeds 4% > 4 OR forecast error exceeds 6% on >= 1 day	# of days that forecast error exceeds 3% > 10 OR # days that forecast error exceeds 4% > 8 OR forecast error exceeds 7% on >= 1 day OR Forecast error resulted in declaring 1 Real Time Event	Control Performance - BAAL	M	Monthly performance score >=2	Monthly performance score <2 but >=1	Monthly performance score < 1

2025 Dashboard Metric Criteria (2 of 2)

*New or revised 2025 Metric;

Operational Excellence									
Metric	Chart	● Expected	■ Monitor	▼ Review	Metric	Chart	● Expected	■ Monitor	▼ Review
Short-Term Load Forecast*	G	Forecast error exceeding the 95% percentile of forecast error for the past year <= 2 days	3 days <= Forecast error exceeding the 95% percentile of forecast error for the past year <= 5 days	Forecast error exceeding the 95% percentile of forecast error for the past year > 5 days	Control Performance – CPS1 and CPS1 12-month rolling	N	>=100%		<100%
					ARS Deployment	P	DCS monthly average % recovery (APR) = 100%	Analysis of event not yet complete	DCS monthly average % recovery (APR) confirmed <100%
Customer Service									
System Impact Study Performance	Q	Studies completed in less than 60 days >=85%	Studies completed in less than 60 days <85% but >=75%	Studies completed in less than 60 days <75%	Settlement Disputes	S	Increase of up to 20 disputes	Increase of between 20 and 50 disputes	Increase of more than 50 disputes

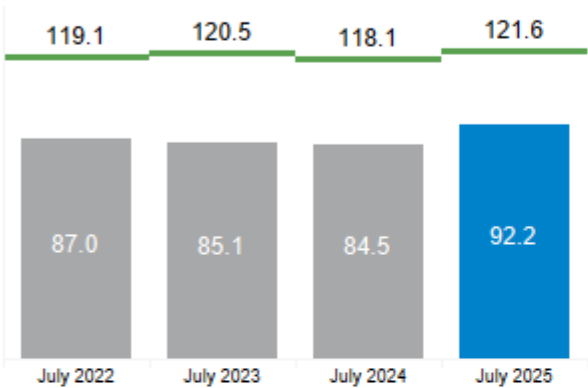


MISO Monthly Operations Report

July 2025

Reliability, markets and operational functions performed as expected in July

AVERAGE & PEAK LOAD (GW)



SYSTEM-WIDE LOAD PEAK



122 GW

July 29, Hour Ending (HE) 17

SOLAR PEAK

13.1 GW

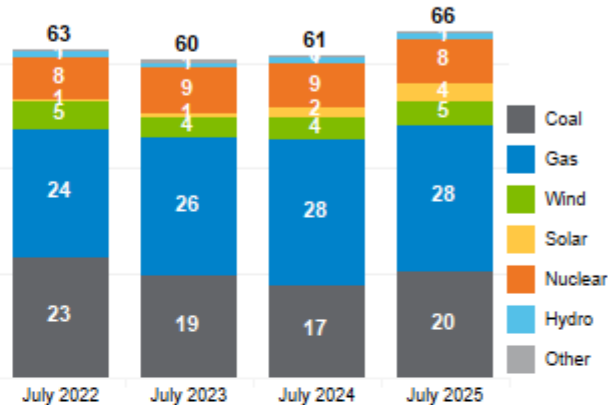
Jul 7, 2025, HE 12

WIND PEAK

15.4 GW

Jul 5, 2025, HE 1

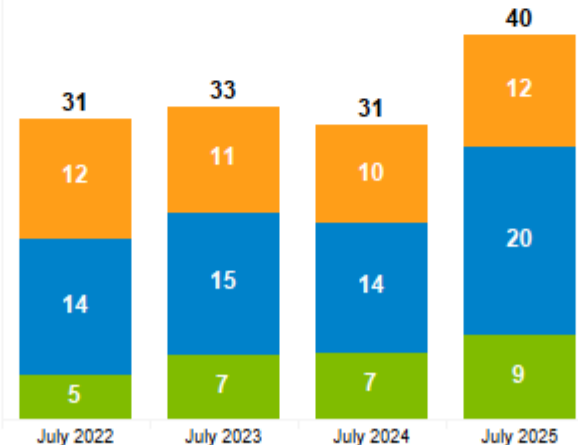
ENERGY FUEL MIX (TWh)



REAL-TIME LMP (\$/MWh)



AVERAGE DAILY GENERATION OUTAGE (GW)



AVERAGE FUEL PRICE (\$MMBtu)



KEY OPERATING DECLARATIONS

JULY 2025

		1	2	3	4	5
6	7	8	9	10	11	12
13	14	15	16	17	18	19
20	21	22	23	24	25	26
27	28	29	30	31		

07/15 System: Conservative Operations
07/16 North: Severe Weather Alert
07/18 System: System Status Level 1
07/21 - 07/24 System: Conservative Operations and Hot Weather Alert
07/28 System: Max Gen Alert
07/29 System: Max Gen Warning
07/28 N/C: Severe Weather Alert
07/28 - 07/29 South: Local Transmission Emergency
07/28 - 07/29 System: Conservative Operations and Hot Weather Alert
07/29 South: Transmission Advisory
07/30 South: Severe Weather Alert

- All-Time Solar Peak: 14.1 GW on Aug 3, 2025, HE 11
- All-Time Wind Peak: 25.7 GW on Jan 12, 2024, HE 19
- All-Time Load Peak: 127.1 GW on Jul 20, 2011, HE 17

- Derated
- Unplanned
- Planned

- Awareness and Weather
- Alerts and Warnings
- Reliability Actions and Events

Dashboard

Metric	Chart	July 2025	Jun '25	May '25	Apr '25	Metric	Chart	July 2025	Jun '25	May '25	Apr '25
Market Efficiency Metric	D	●	▼	●	●	Unit Commitment Efficiency	H	●	●	●	●
Percentage Price Deviation	A	▼	■	■	■	Day Ahead Wind Generation Forecast Error	K	●	●	●	●
Monthly Average Gross Virtual Profitability	B	●	●	●	●	Day-Ahead Solar Generation Forecast Error	T	●	●	●	●
FTR Funding	C	●	●	●	●	Tie Line Error	L	●	●	●	●
RSG per MWh to Energy Price	E	●	●	●	●	Control Performance – BAAL	M	●	●	●	●
Day Ahead Mid-Term Load Forecast	F	●	●	■	▼	Control Performance – CPS1 and CPS1 12-month rolling	N	●	●	●	●
Short-Term Load Forecast	G	●	●	●	■	ARS Deployment	P	●	●	●	●
Real-Time Obligation fulfilled by Day-Ahead Supply at the Peak Hour	I	●	●	●	●						
System Impact Study Performance	Q	●	▼	●	▼	Settlement Disputes	S	●	●	●	●

● Expected ■ Concern/Monitor ▼ Review

One metric fell outside of the expected range for this month

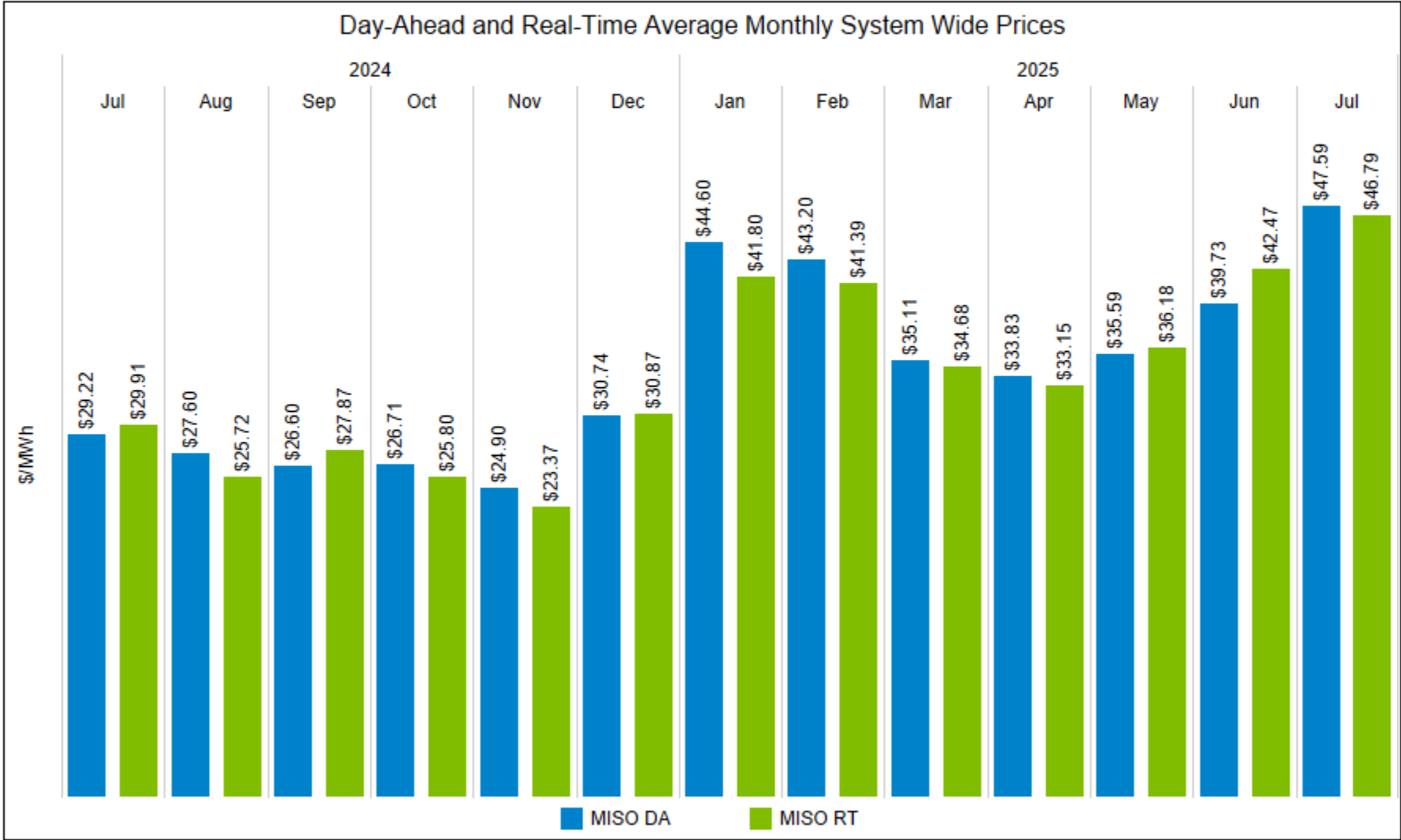
Metric	Expected Criteria	Actual	Status	Comments
Percentage Price Deviation	Absolute DA-RT price difference divided by DA LMP $\leq 28.6\%$	37.0%	Review	Periods of congestion, especially on July 28th and July 30th, and Real-Time ancillary service product scarcity pricing throughout the month resulted in some price divergence between the Day-Ahead and Real-Time markets.

Appendix

Contents

Pricing	MISO System-wide DA and RT LMPs	7
	Price Convergence: DA and RT LMP	8
	MISO DA and RT Hub LMPs	9
	Ancillary Services – DA and RT Market Clearing Prices	10
	Ancillary Services – DA and RT Market Clearing Prices	11
	Nominal Fuel Prices	12
Settlements	Monthly Average Gross Virtual Profitability	13
	Daily Gross Cleared Virtual Profitability	14
	DA Congestion Collections	15
	Real-Time Congestion Dollars by Region	16
	FTR Monthly and YTD Allocation Funding	17
	Market Efficiency Metric	18
	DA and RT Revenue Sufficiency Guarantee	19
	Price Volatility and Make Whole Payment	20
	DA and RT Cleared Physical Energy	21
Load	Monthly System Load and Temperature	22
	Day-Ahead Mid-Term Load Forecast	23
	Short-Term Load Forecast	24
	Average Load by Region	25
	Market Participant Entered LMR Availability	26
	Regional Directional Transfer	27
Unit Commitment	Unit Commitment Efficiency	28
	DA Supply and RT Obligation at the Peak Load Hour	29
	Self-Committed and Economically Dispatched Energy	30
	Trend in Self Commitment and Economically Dispatched Energy	31
	Offered Capacity and RT Peak Load Obligation	32
Generation	Marginal Fuel	33
	RT Generation Fuel Mix	34
	Dispatched Generation Fuel Mix by Region	35
	DA Wind Forecast Performance: MAE	36
	DA Wind Forecast Performance: MAPE	37
	Monthly Wind Energy	38
	Daily Wind Generation and Curtailment	39
	DA Solar Forecast Performance: MAE	40
	DA Solar Forecast Performance: MAPE	41
	Monthly Solar Energy	42
	Daily Solar Generation and Curtailment	43
	Carbon Emissions	44
	Monthly Generation Outages and Derates	45
	Generation Outages by Fuel	46
Reliability	Transmission Outages	47
	Inadvertent Balance	48
	Generation Notifications	49
	Tie Line and BAAL Performance	50
	CPS1 Performance	51
	Reliability – Other Metrics	52
	Operator Actions: Manual Redispatch and Caps	53
Transmission Planning	Transmission Service Request	54
	Generator Suspension/ Retirement – New and Resolved	55
	Generation Suspension/Retirement – Overall	56
Customer Service	Settlements/Customer Service	57
	Market Operations IT Applications Availability	58

MISO System-wide Day-Ahead and Real-Time Locational Marginal Pricing

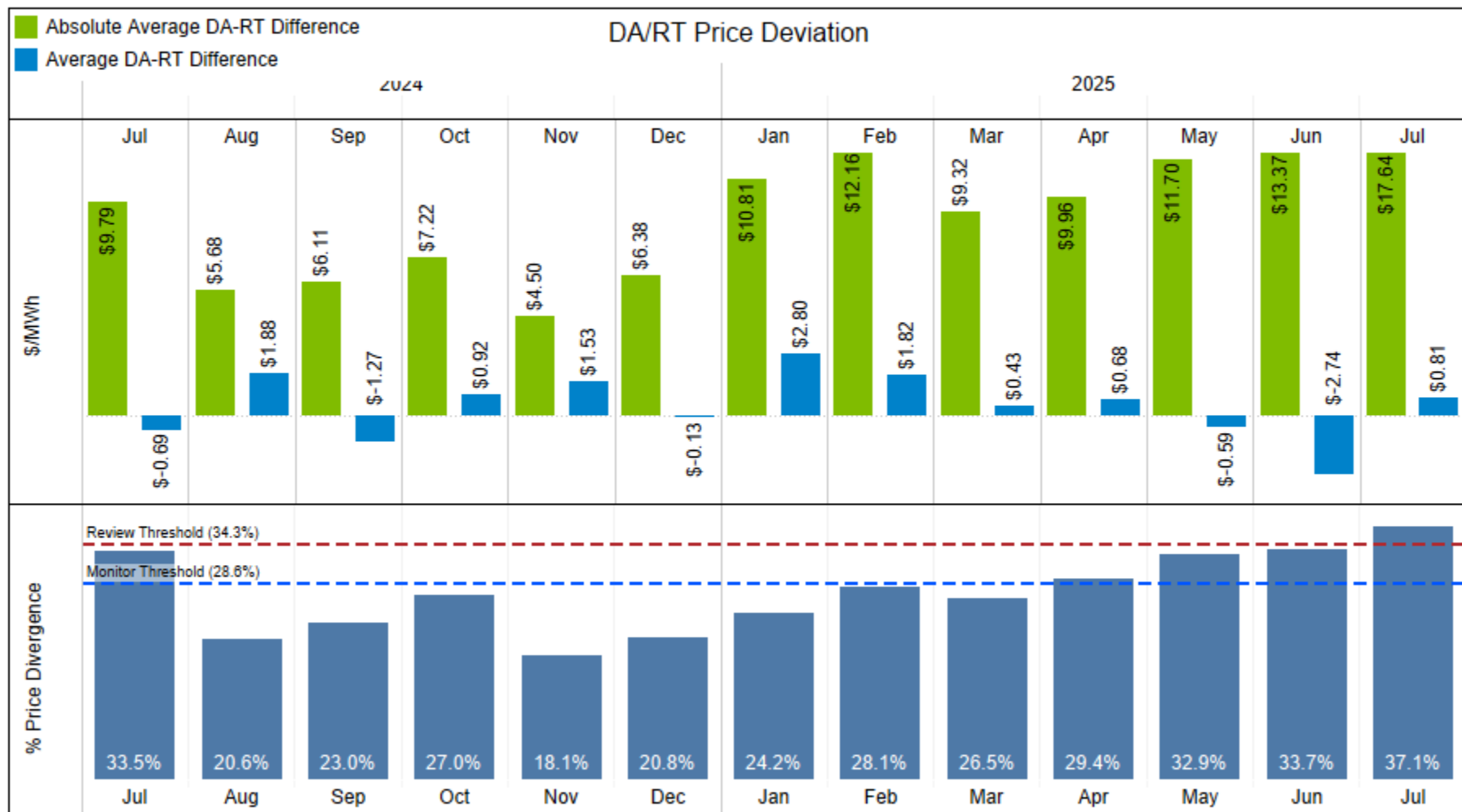


Note: MISO System-Wide price is based on the monthly hourly average of the active hubs
Source: MISO Market and Operations Analytics Department



Price Convergence: Day-Ahead and Real-Time Locational Marginal Pricing

A

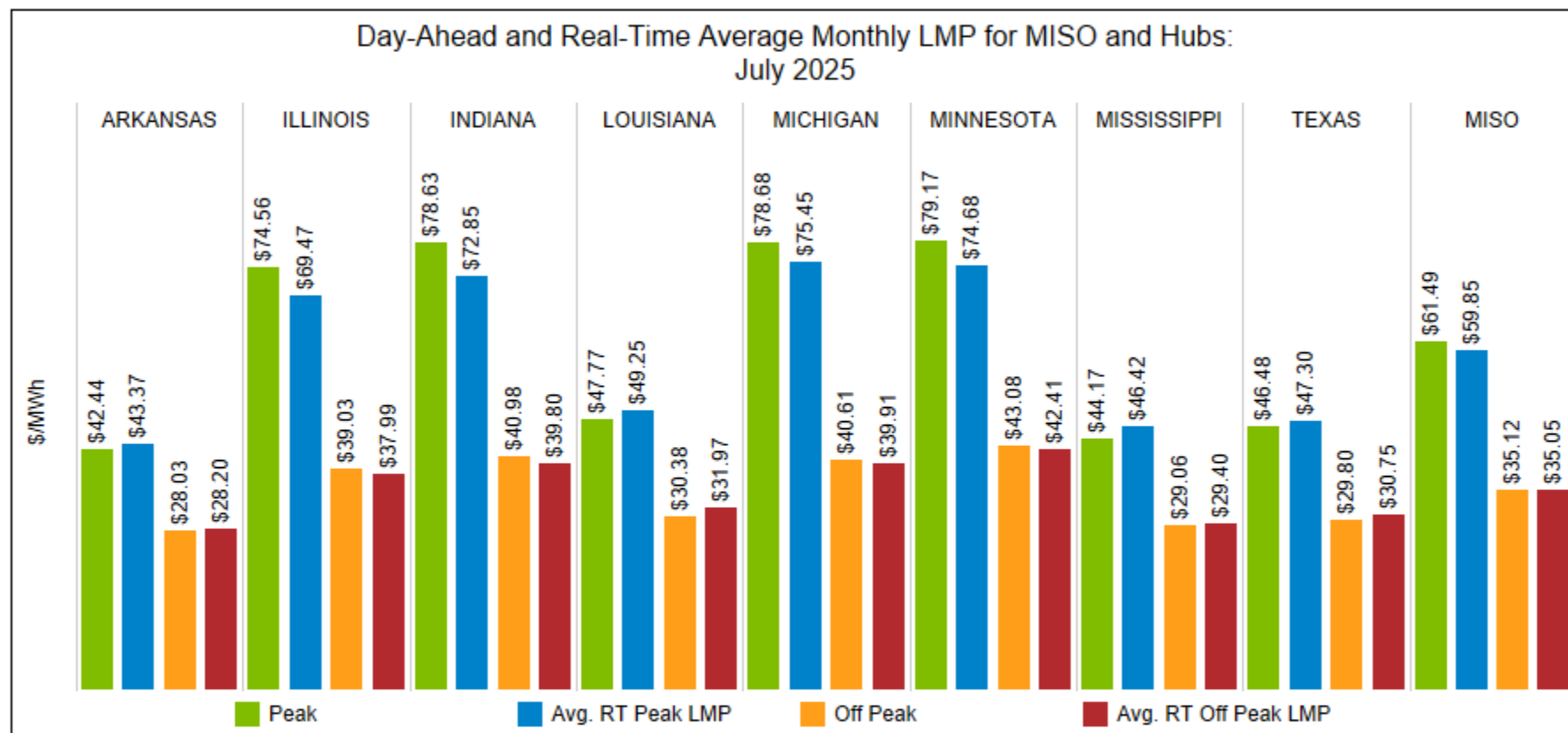


*Monthly deviation, expressed as a percent of average DA LMP, is calculated as the average of hourly absolute (DA-RT) price difference divided by the average of hourly DA LMPs for the month

Note: MISO System-Wide price is based on the monthly hourly average of the active trading hubs
 Source: MISO Market and Operations Analytics Department



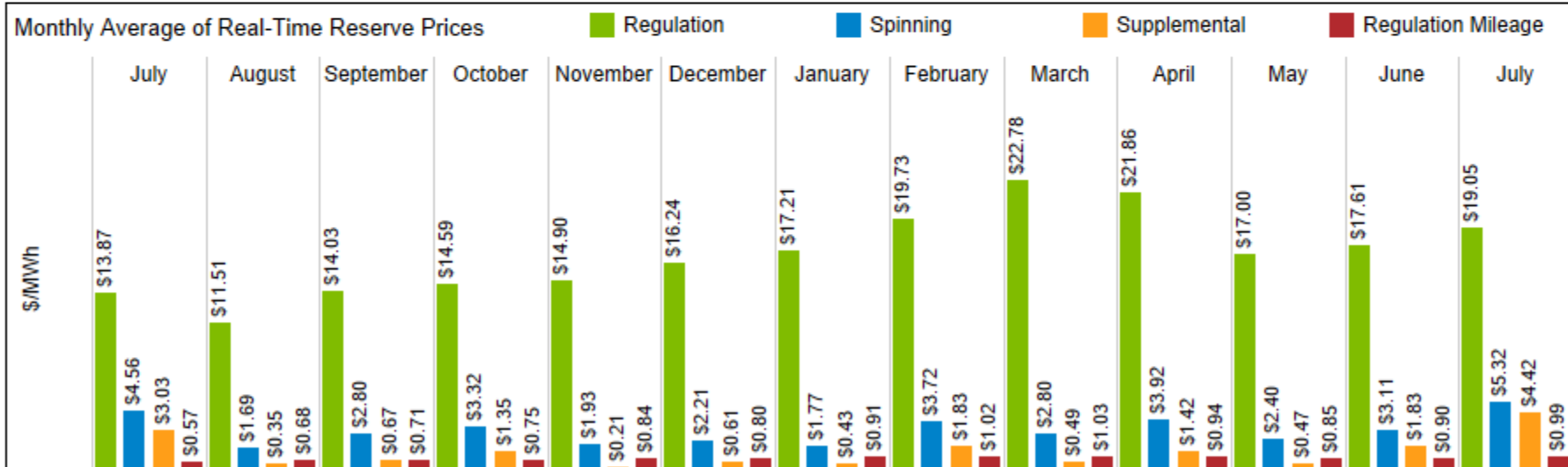
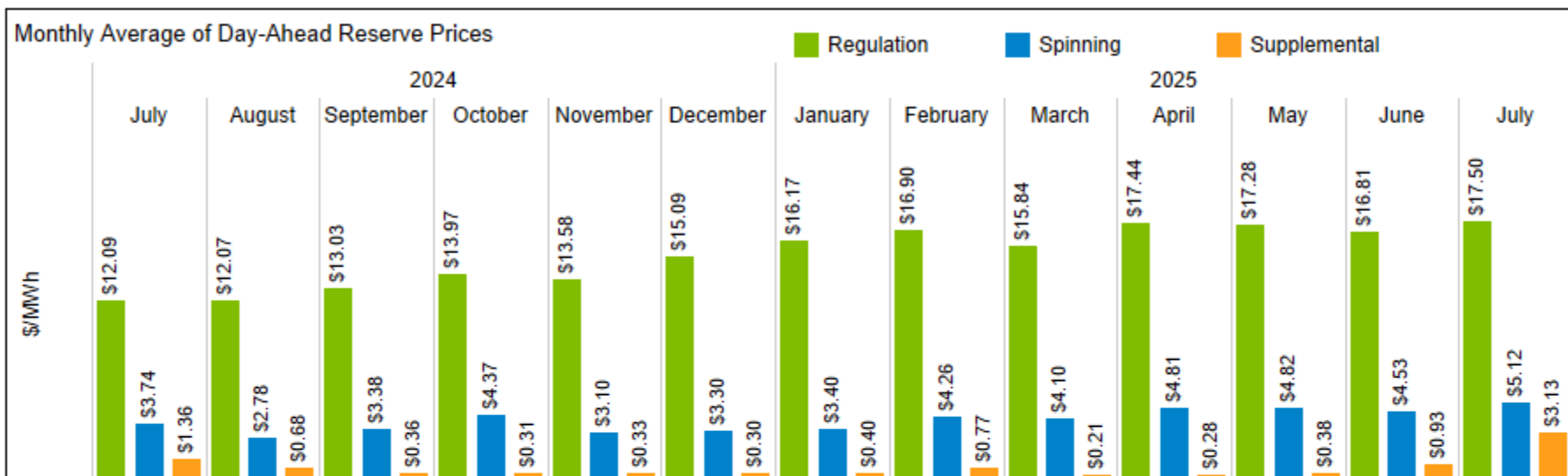
MISO Day-Ahead and Real-Time Hub Locational Marginal Pricing



		ARKANSAS	ILLINOIS	INDIANA	LOUISIANA	MICHIGAN	MINNESOTA	MISSISSIPPI	TEXAS	MISO
Marginal Congestion Component of LMP (\$/MWh)	DA Peak	-30.03	-0.48	1.03	-27.70	0.85	4.21	-29.51	-28.40	-13.75
	RT Peak	-24.50	-0.48	0.57	-21.55	2.74	1.98	-22.84	-22.69	-10.85
	DA Off Peak	-9.83	0.05	0.56	-9.27	0.25	3.42	-9.58	-9.37	-4.22
	RT Off Peak	-8.98	-0.23	0.08	-7.17	0.18	3.32	-8.65	-7.91	-3.67

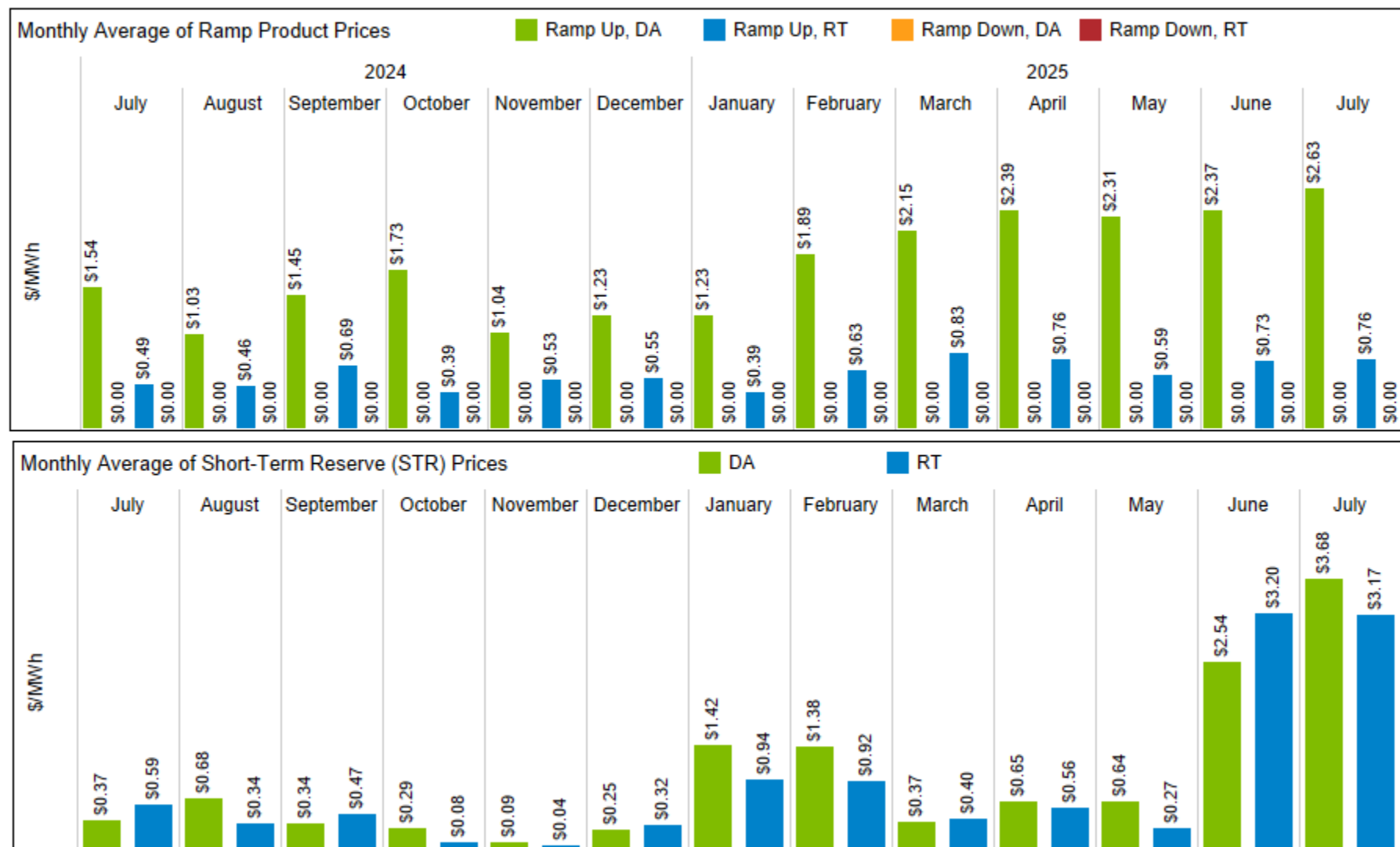
Source: MISO Market and Operations Analytics Department

Ancillary Services - Day-Ahead and Real-Time Market Clearing Prices



Source: MISO Market and Operations Analytics Department

Ancillary Services - Day-Ahead and Real-Time Market Clearing Prices



Source: MISO Market and Operations Analytics Department

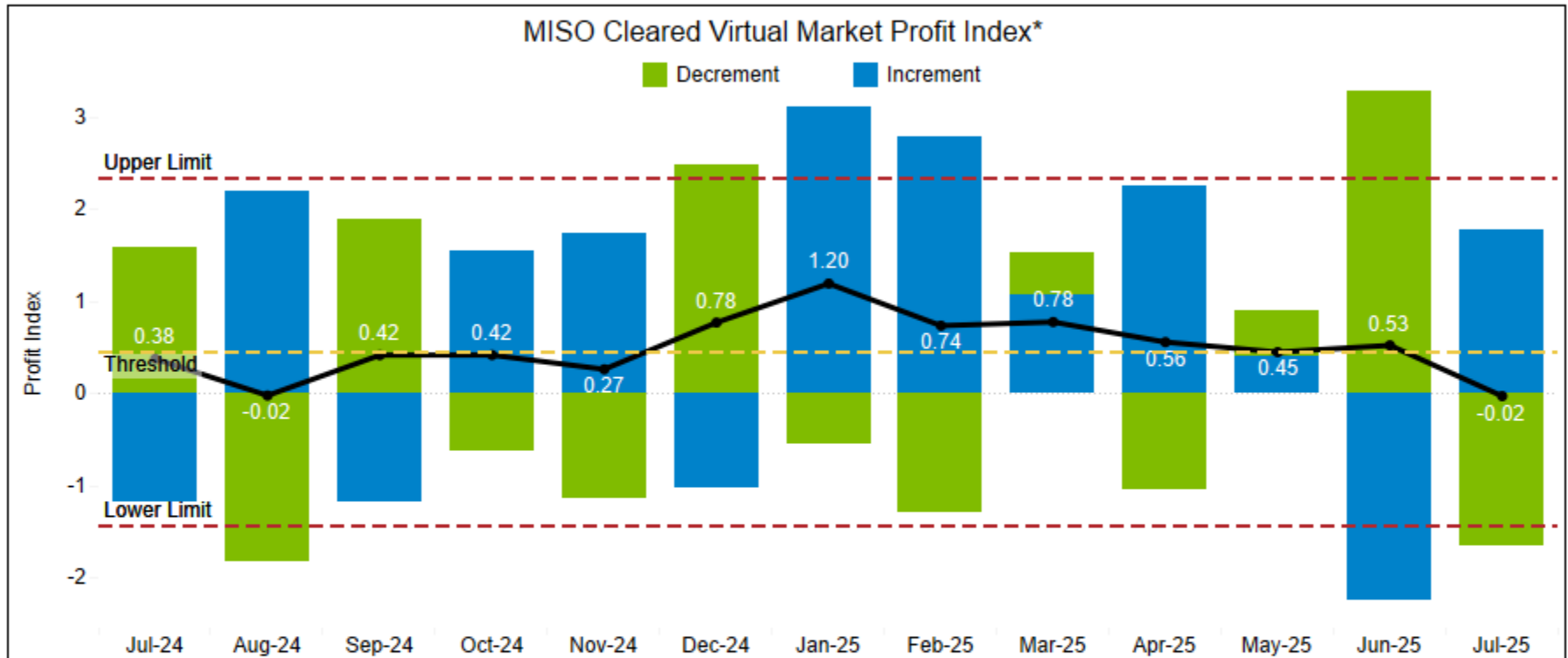
Nominal Fuel Prices



Monthly oil prices are estimates and subject to change upon finalization
Source: EIA

Monthly Average Gross Virtual Profitability

B



Monthly Standard Deviation

Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25
2.96	0.86	1.32	1.21	1.74	1.50	2.60	2.21	1.16	1.15	2.04	1.61	2.64

* The virtual profitability market index is defined as the sum of profits/losses for all cleared virtual transactions divided by the volume (MWh) of total cleared transactions.

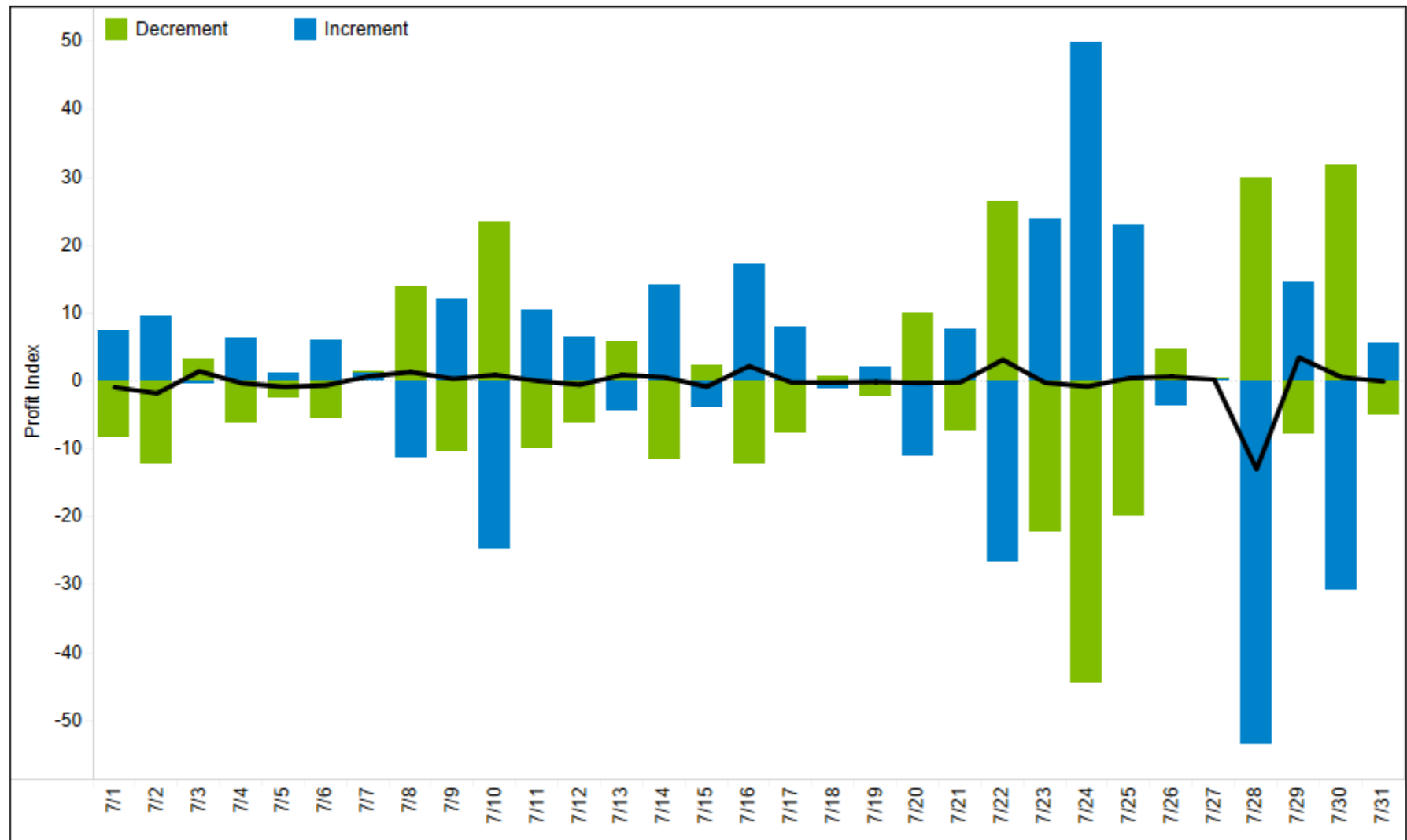
* Virtual profits/losses are calculated by multiplying the cleared virtual MW and the imbalance between RT LMP and DA LMP for a cpnode, then summed across all cpnodes, all hours.

* Upper Limit is Threshold (average of monthly indices from the previous year) plus Daily Average Standard Deviation for the previous 13 months (current reporting month inclusive)

* Lower Limit is Threshold (average of monthly indices from the previous year) minus Daily Average Standard Deviation for the previous 13 months (current reporting month inclusive).

Source: MISO Market and Operations Analytics Department

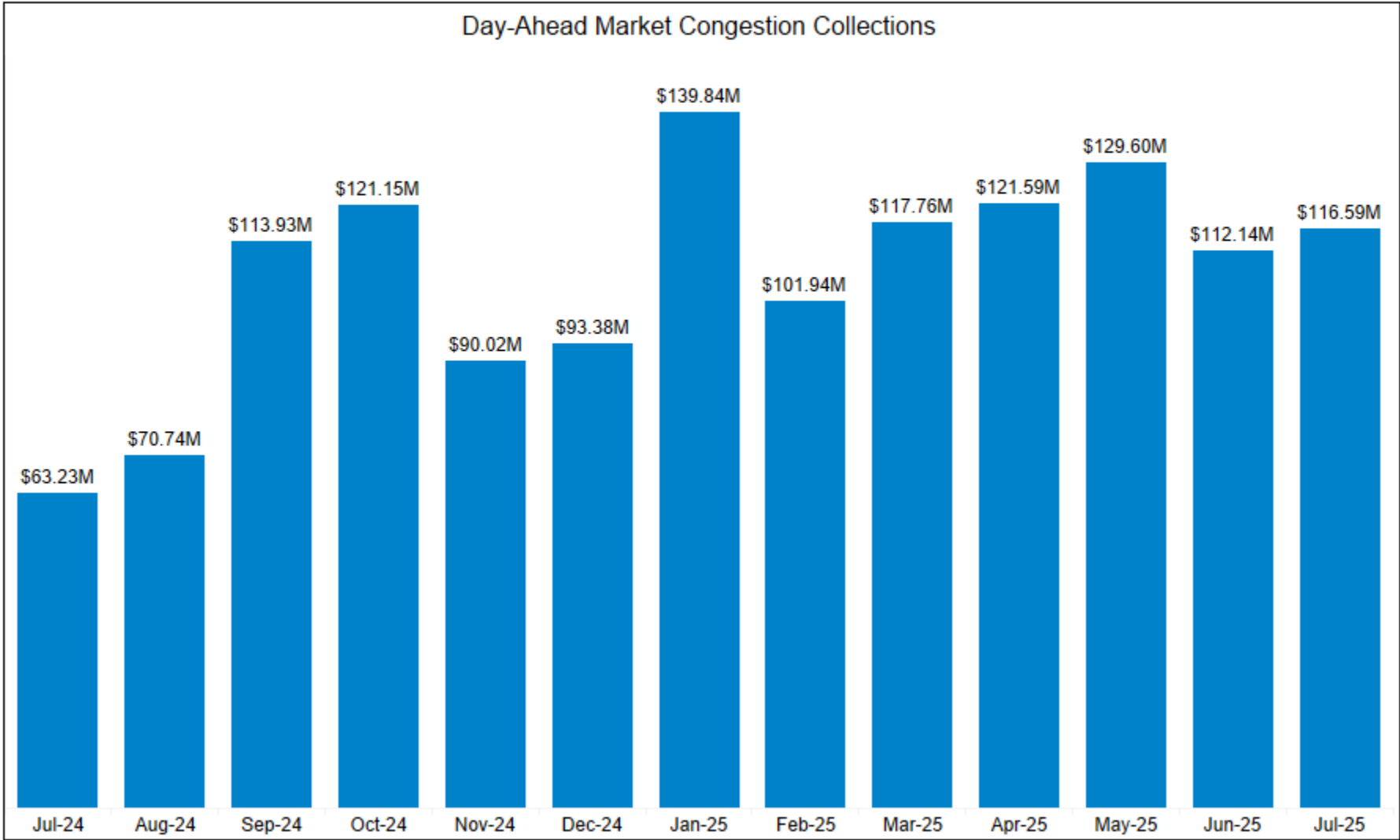
Daily Gross Cleared Virtual Profitability



The virtual profitability market index is defined as the sum of profits/losses for all cleared virtual transactions divided by the volume (MWh) of total cleared transactions

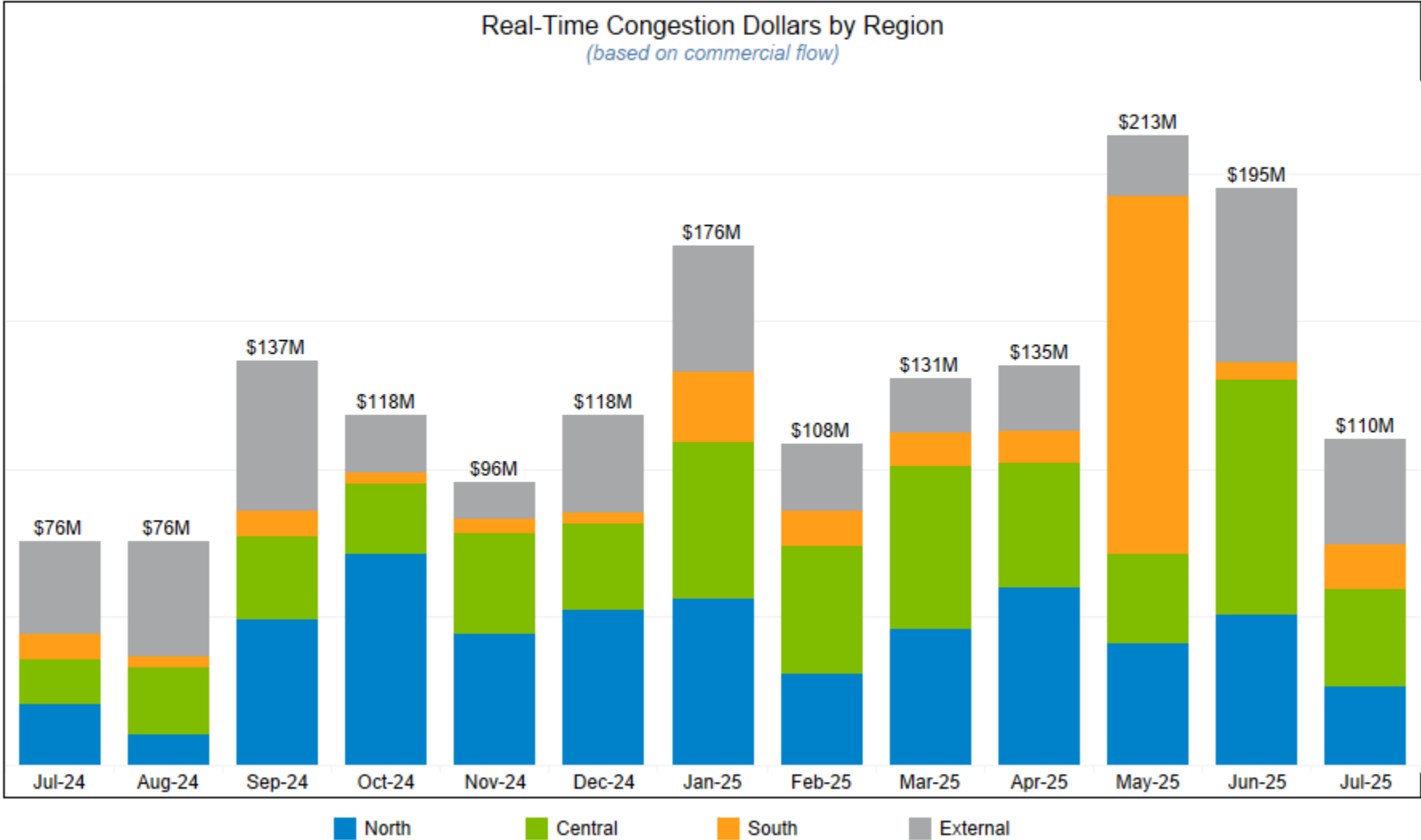
Source: MISO Market and Operations Analytics Department

Day-Ahead Congestion Collections



Source: MISO Market and Operations Analytics Department

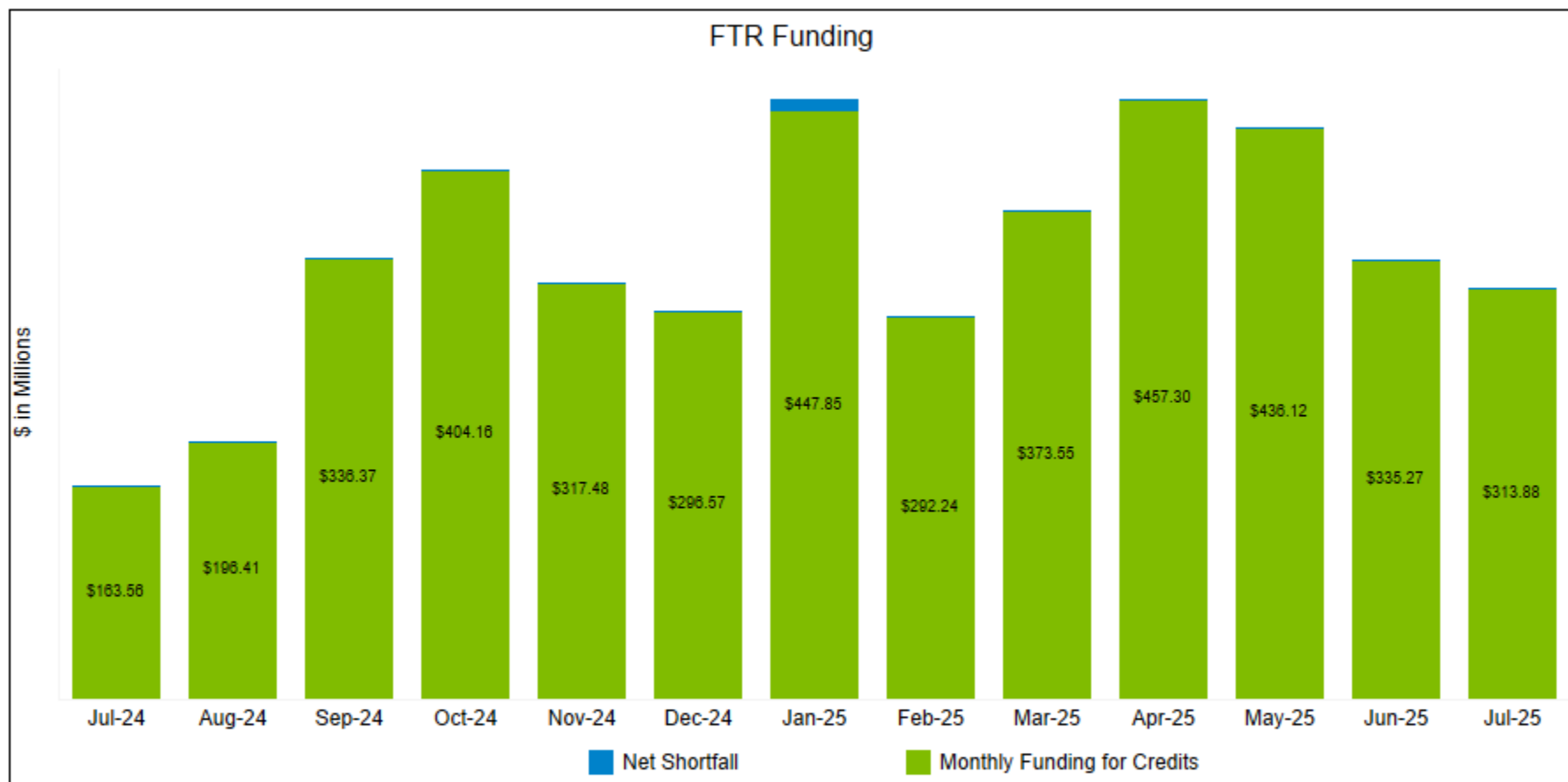
Real-Time Congestion Dollars by Region



Includes External Constraints
Commercial Flow excludes phase angle regulators and loop flows
Source: MISO Market and Operations Analytics Department

Financial Transmission Rights, Monthly and Rolling Year-to-Date Allocation Funding

C

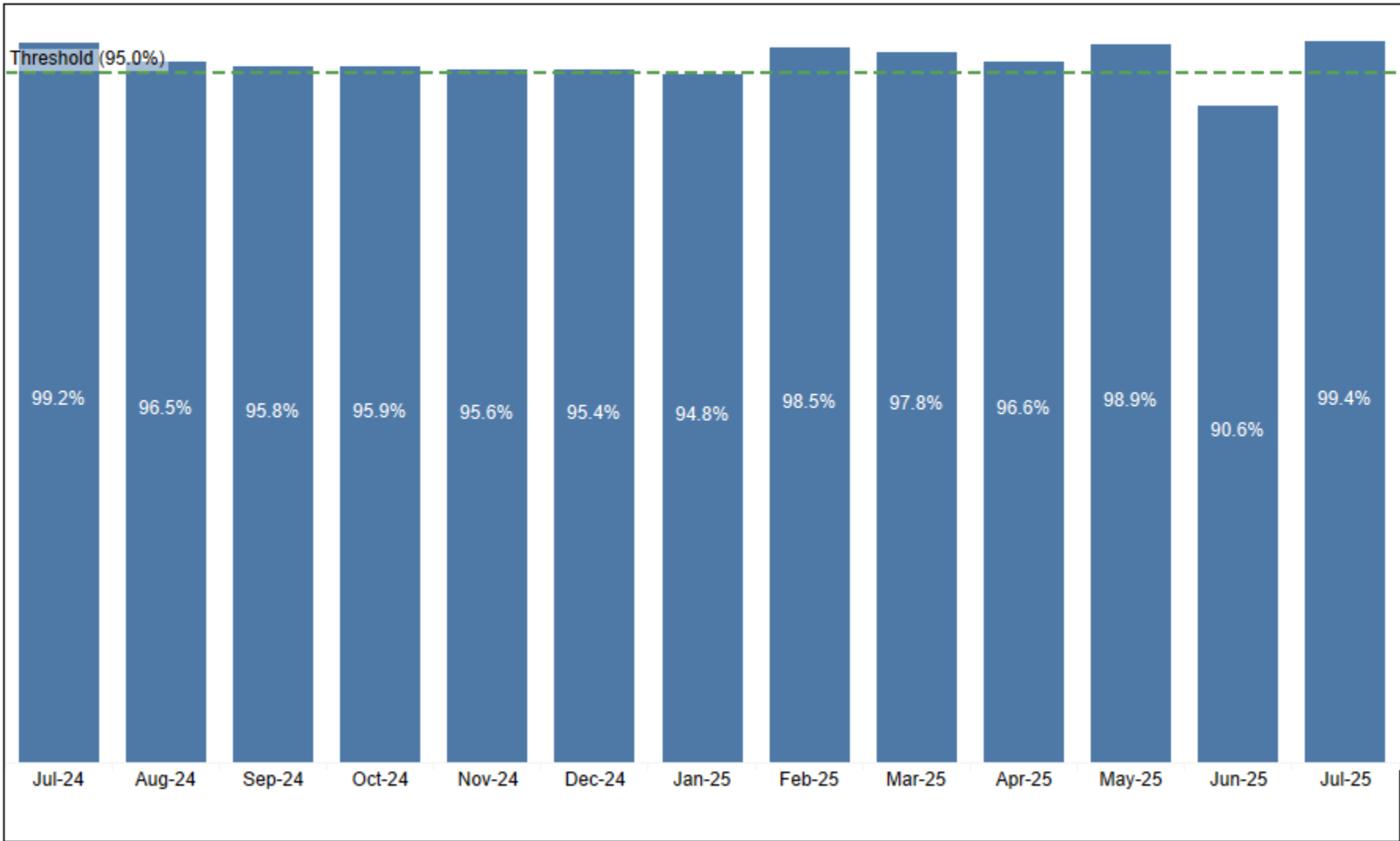


	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25
Monthly FTR Allocation (%)	100.0%	100.0%	99.9%	100.0%	100.0%	100.0%	97.8%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
YTD FTR Allocation (%)	96.3%	96.7%	97.1%	97.5%	97.8%	98.0%	NA	NA	NA	100.0%	100.0%	100.0%	100.0%

YTD metric is applied beginning April
 Values may change due to resettlement
 Source: MISO Market ECF Report

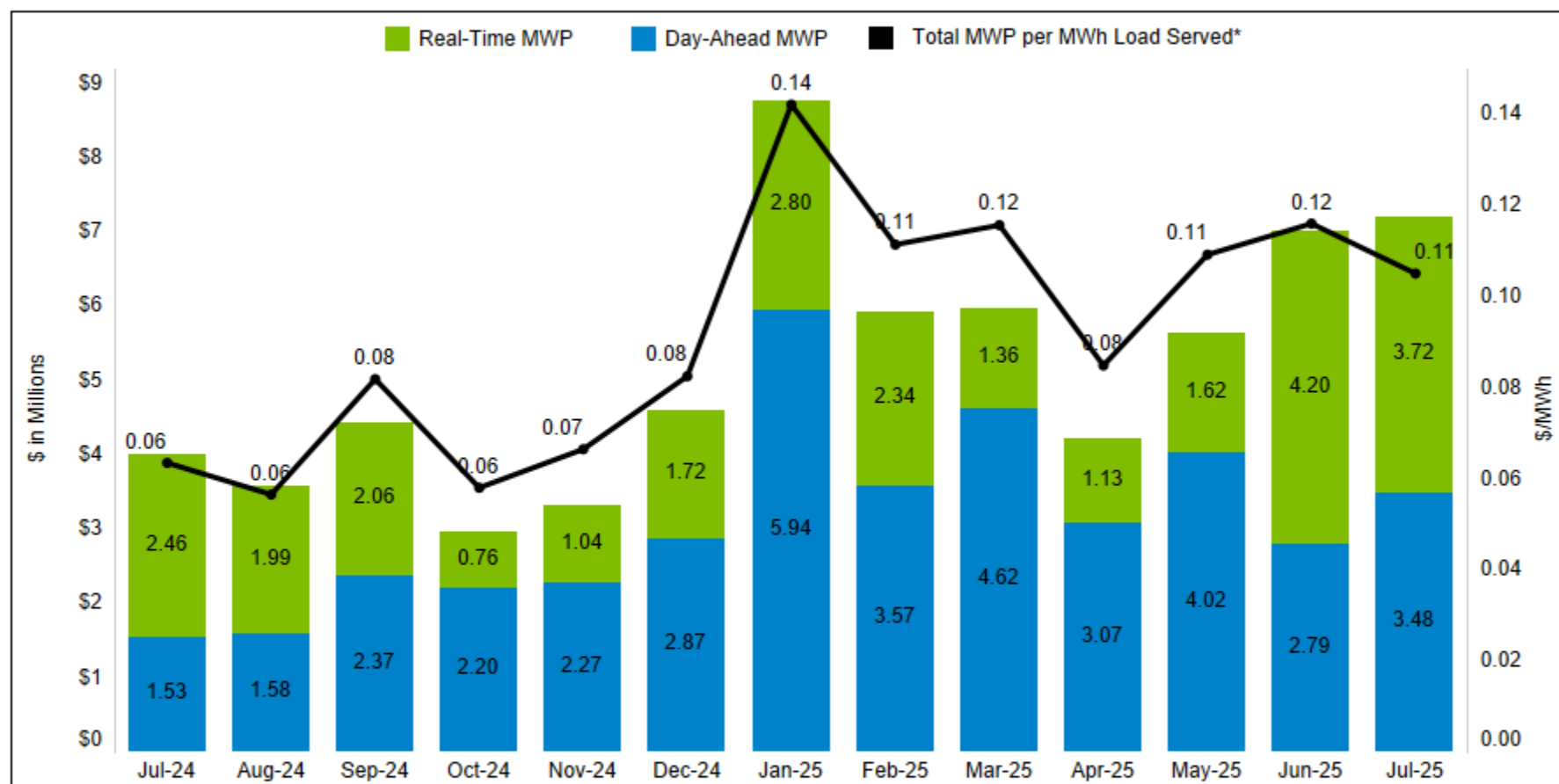
Market Funding Efficiency

D



Values may change due to resettlement
Source: MISO Market ECF Report

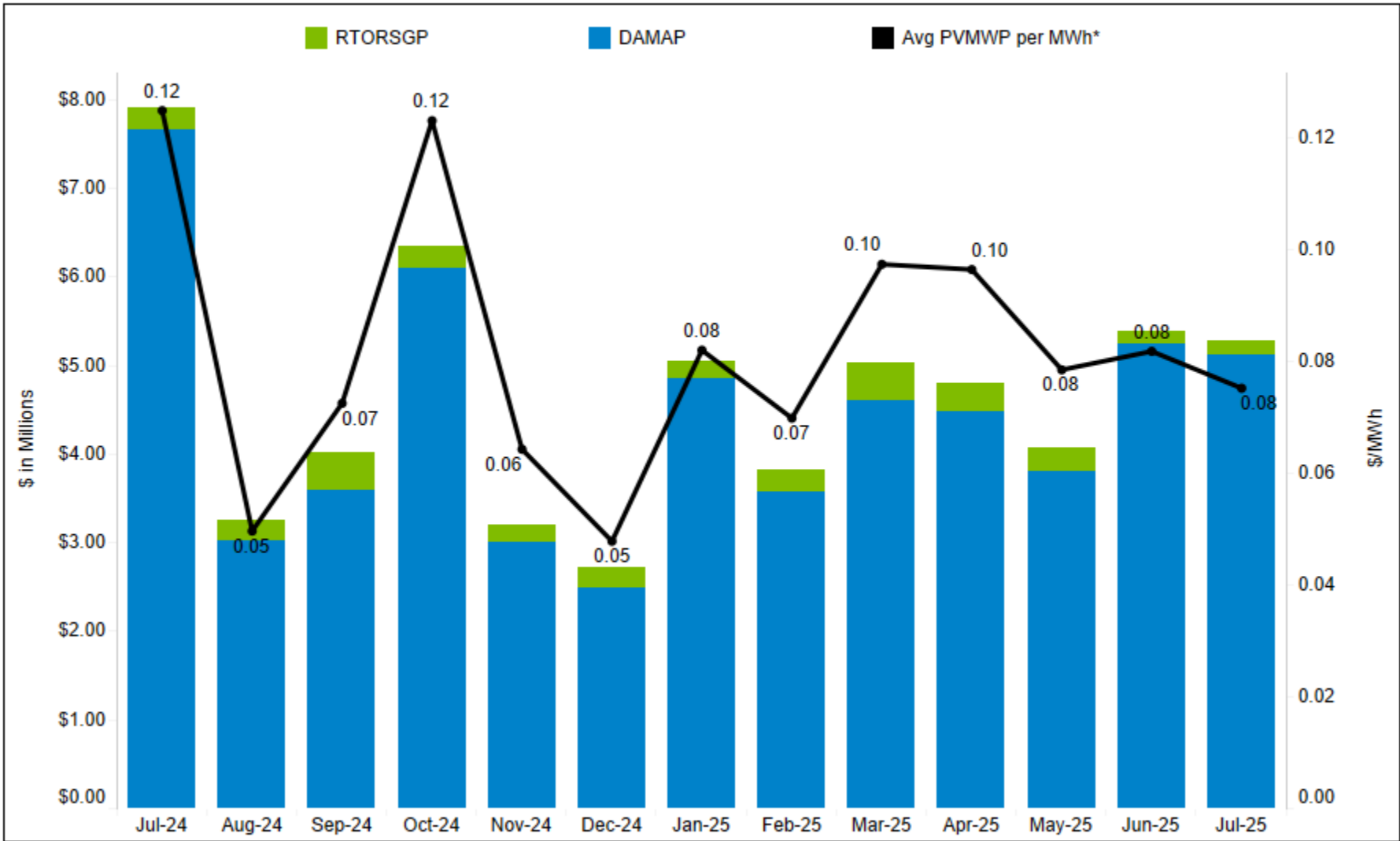
Day-Ahead and Real-Time Revenue Sufficiency Guarantee E



	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25
Chicago Gas Prices (\$/MMBtu)	1.73	1.70	1.86	2.10	1.77	2.74	5.30	4.10	3.54	3.09	2.85	2.73	2.93
Henry Gas Prices (\$/MMBtu)	2.09	1.98	2.23	2.26	2.16	3.03	5.40	4.13	4.10	3.43	3.12	3.01	3.25
^^RSG Per MWh to Energy Price (%)	0.22	0.20	0.31	0.22	0.27	0.27	0.32	0.26	0.33	0.25	0.31	0.29	0.22

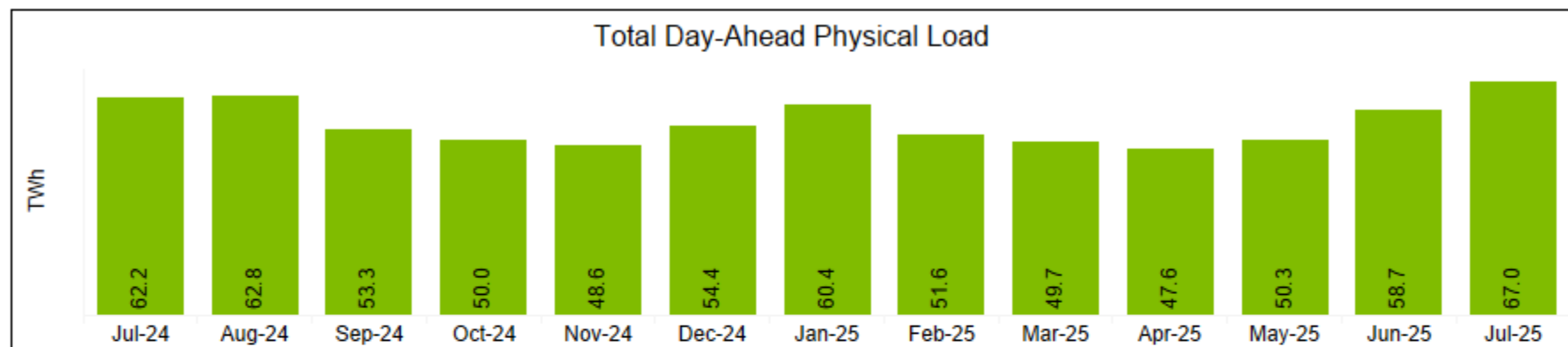
*Based on hourly ICCP Data; ^^metric value
 Values may change due to resettlement
 Source: The Web-based Revenue Sufficiency Guarantee Report

Price Volatility Make Whole Payment



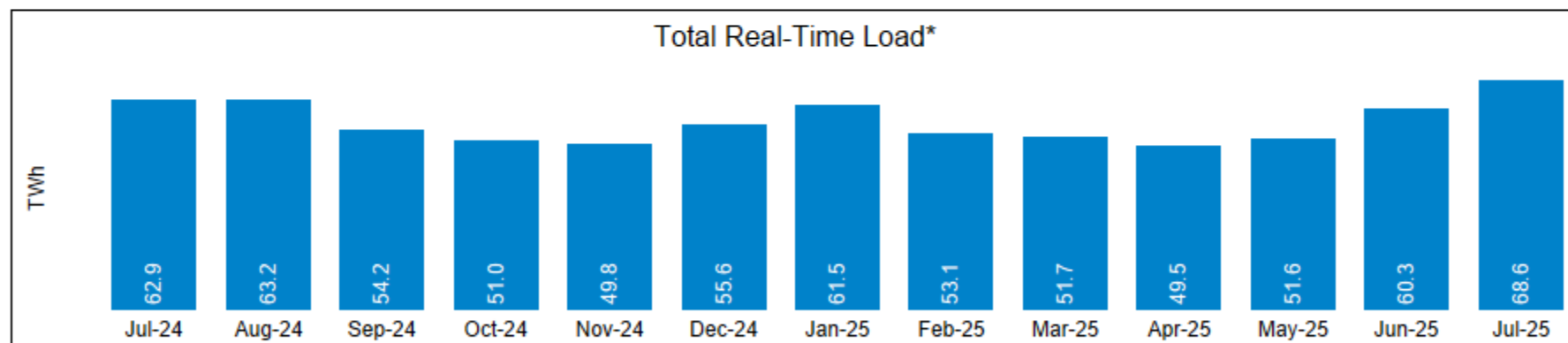
*Hourly ICCP data
Source: Web-based Revenue Neutrality Uplift Report

Day-Ahead and Real-Time Cleared Physical Energy



Day-Ahead Cleared Load Value (including Virtuals)

Month	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25
Value (\$B)	\$2.37B	\$2.20B	\$1.74B	\$1.57B	\$1.44B	\$2.06B	\$3.20B	\$2.68B	\$1.93B	\$1.87B	\$2.14B	\$2.97B	\$4.17B

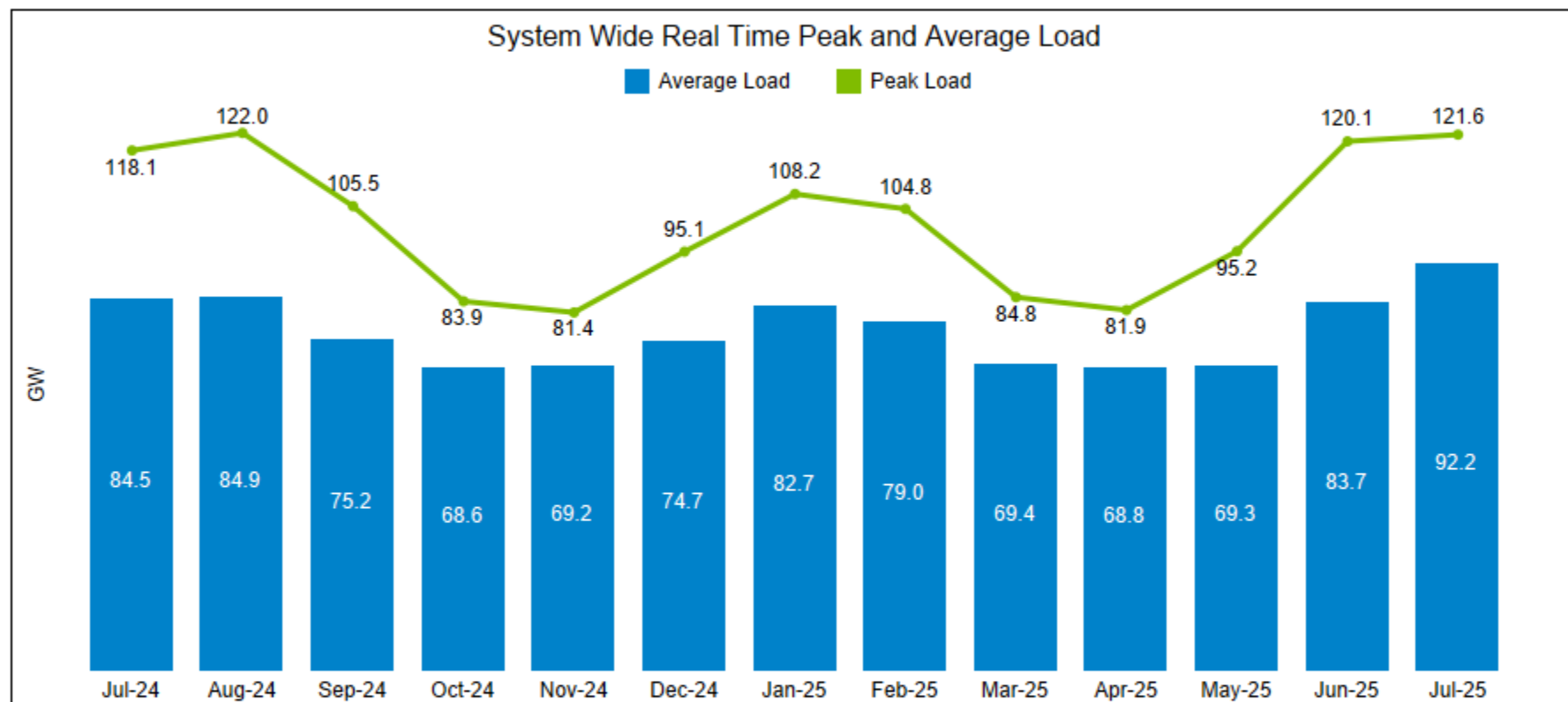


Real-Time Cleared Load Value (\$ in Billions)

Month	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25
Value (\$B)	\$2.14B	\$1.81B	\$1.63B	\$1.29B	\$1.18B	\$1.83B	\$2.64B	\$2.21B	\$1.65B	\$1.55B	\$1.95B	\$3.00B	\$3.68B

*Sum of Hourly ICCP Load Data
Source: MISO Market and Operations Analytics Department

Monthly System Load and Temperature



System Wide Load Weighted Temperature			
	Jul-24	Jun-25	Jul-25
Average	78°F	76°F	81°F
Maximum	98°F	100°F	99°F
Minimum	61°F	52°F	66°F

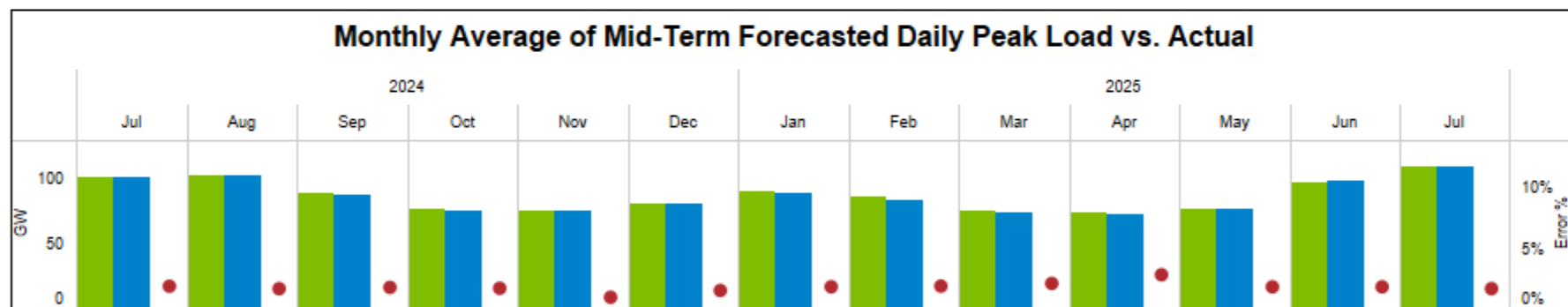
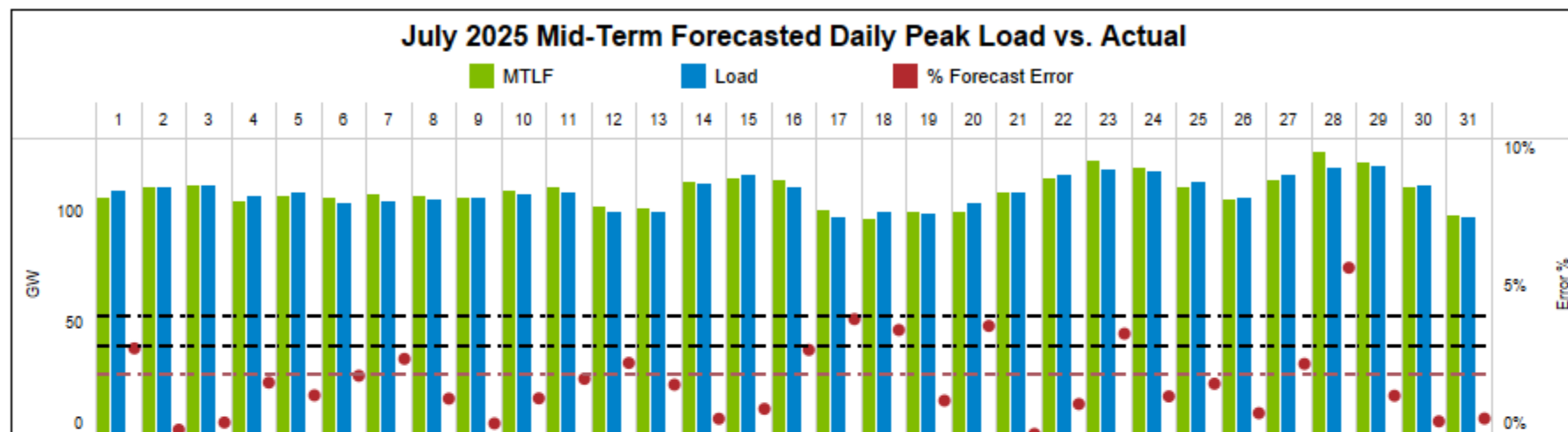
Load Weighted Heating & Cooling Degree Days				
	Average HDD	Std Dev HDD	Average CDD	Std Dev CDD
Jul-25	0.00	0.00	19.19	7.25
Jun-25	0.14	0.94	14.60	8.60
Jul-24	0.00	0.02	16.20	7.34

Hours with Load Greater than:			
	100 GW	80 GW	60 GW
Jul-25	245	560	744
Jun-25	110	415	709
Jul-24	95	446	744

*Monthly data based on hourly ICCP Load Data; Hourly Integrated Peak Load Hour could differ from the Instantaneous Peak Load Hour.
Source: MISO Market and Operations Analytics Department

Day-Ahead Mid-Term Load Forecast*

F



	2024						2025						
	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul
% Std of Error (CV)	78.54	67.80	71.09	68.94	101.98	81.76	77.55	60.87	54.00	40.07	78.67	71.95	75.03
Mean of Error (MW)	1,980	1,845	1,700	1,418	814	1,334	1,742	1,674	1,671	2,191	1,474	1,852	1,950
Std of Error (MW)	1,515	1,251	1,209	978	830	1,090	1,351	1,019	902	878	1,159	1,332	1,463

* Monthly data based on the average of the daily integrated peak hours in the month

* Daily data based on the integrated peak hour of the day

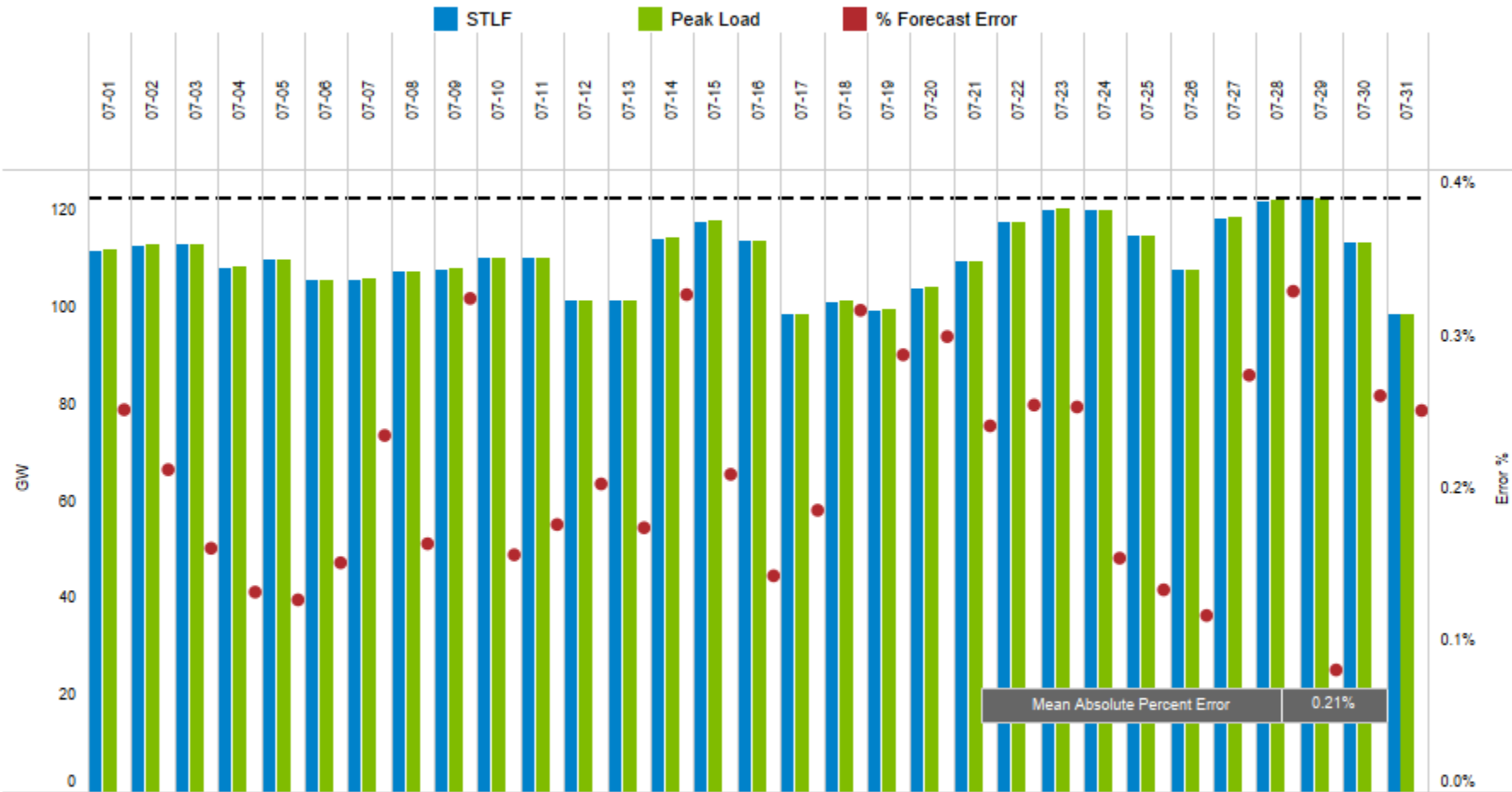
* Peak Day and Hour End based on Hourly Integrated Peak Load Hour

Source: MISO Operations Risk Management



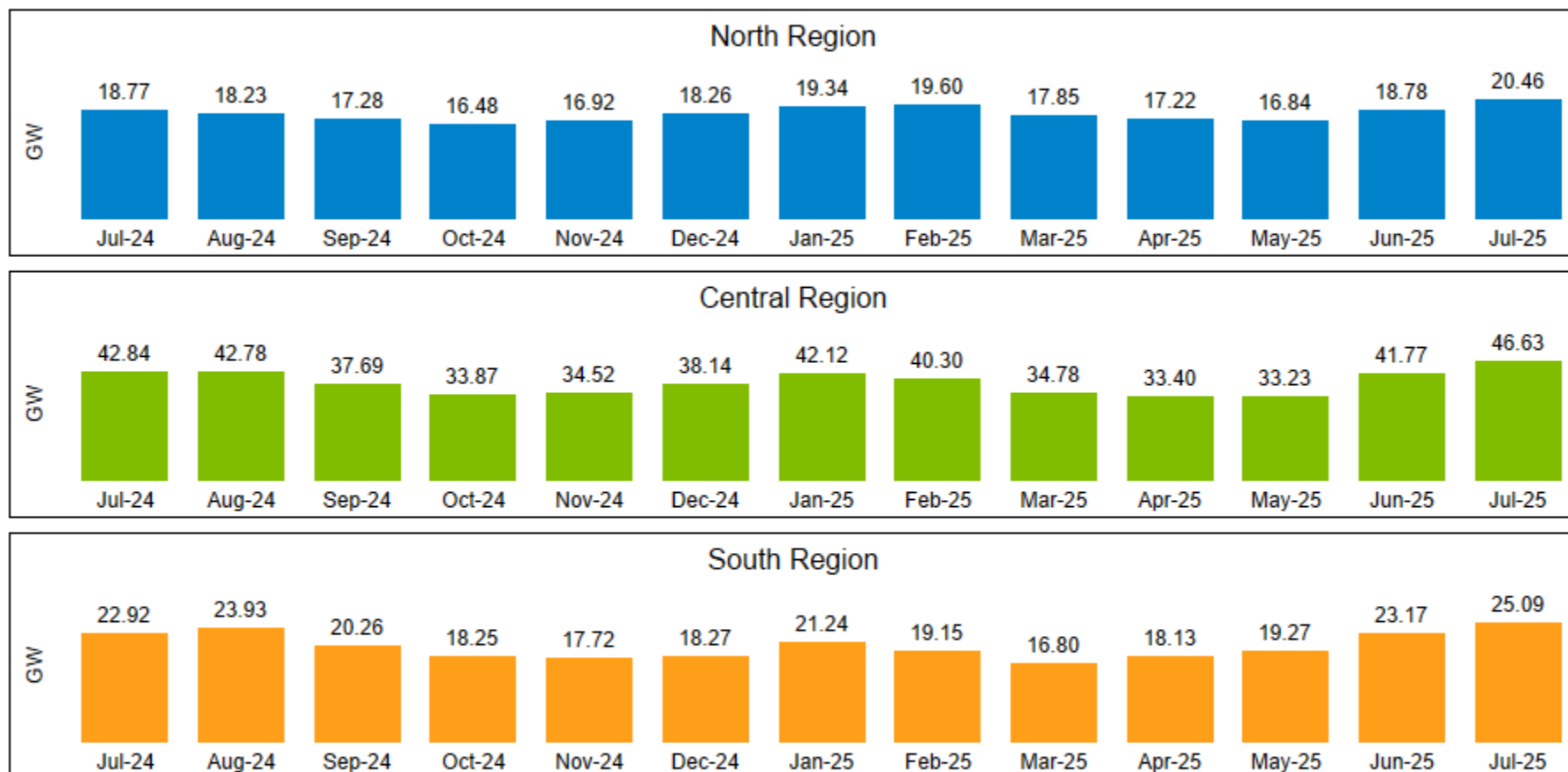
Short-Term Load Forecast*

July 2025 Short-Term Forecasted Daily Peak Load vs Actual



Daily data based on the average of five-minute interval data at the peak hour of the day
Error Threshold calculated as 95% quantile of Forecast Error from Jan-Dec of the previous year
Peak Day and Hour End based on Hourly Integrated Peak Load Hour

Average Load by Region



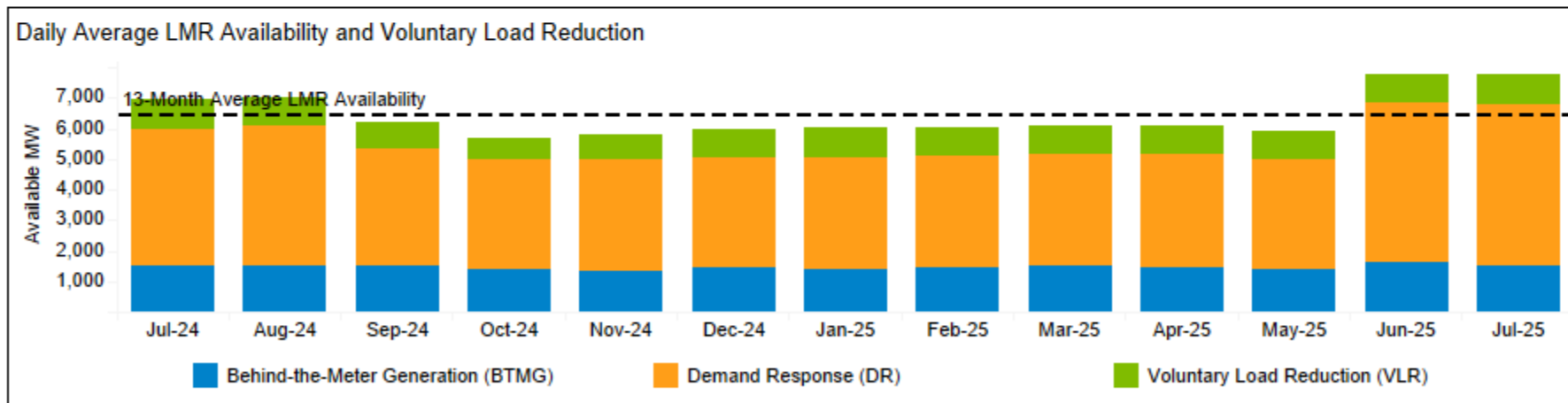
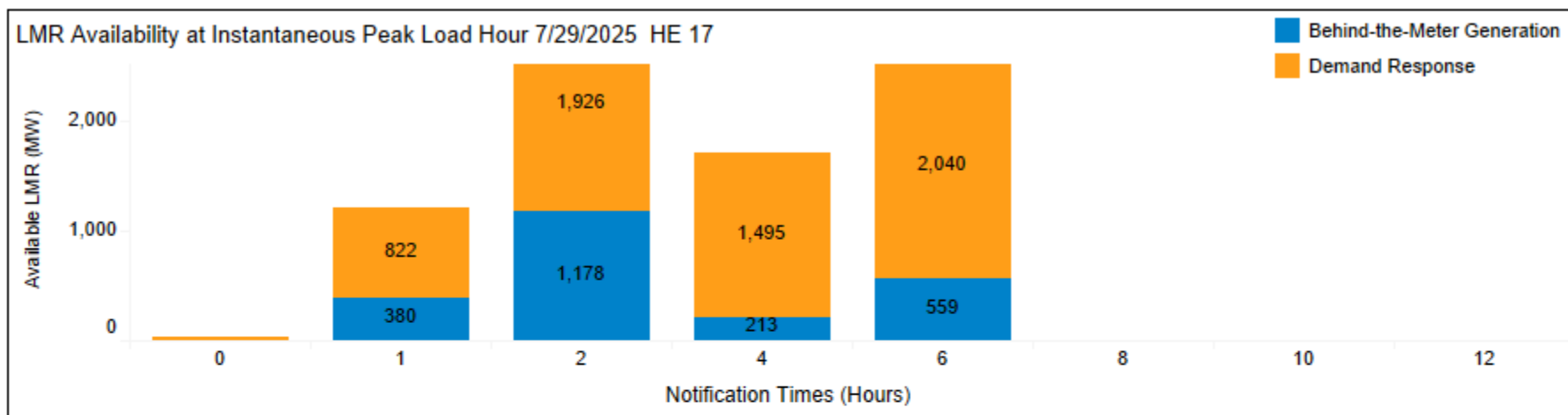
Hourly Integrated System Load Peak Hour Ending: 07/29/2025 17 EST

North	26.22 GW
Central	64.60 GW
South	33.55 GW
MISO	120.94 GW

**Monthly data based on hourly ICCP Load Data; Hourly Integrated Peak Load Hour could differ from the Instantaneous Peak Load Hour.
Source: MISO Market and Operations Analytics Department*



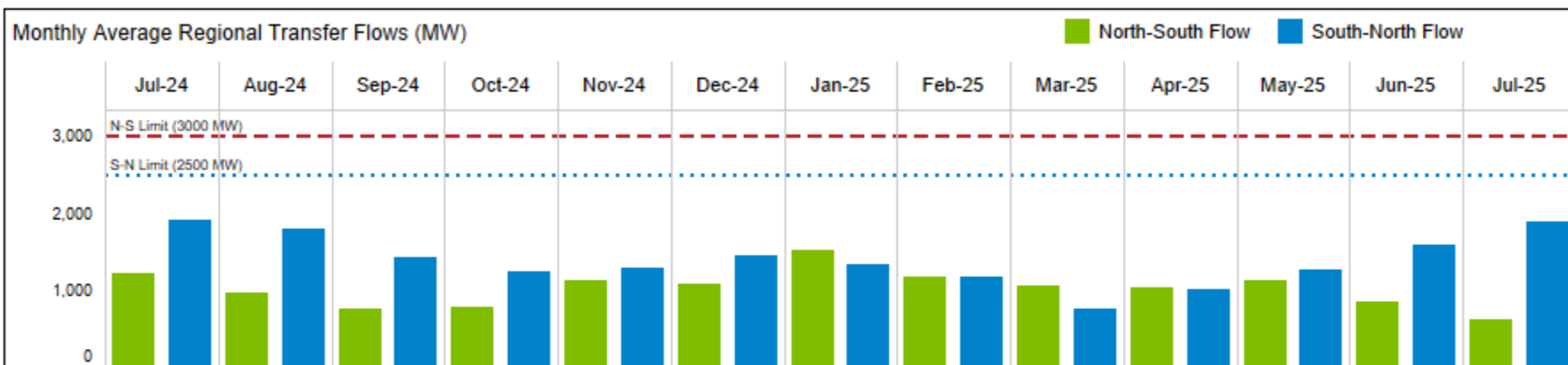
Market Participant entered Load Modifying Resource (LMR) Availability



PRA Auction	BTMG (MW)	DR (MW)	Total BTMG and DR (MW)
Summer 2024	4,144	8,109	12,253
Summer 2025	4,283	9,004	13,287

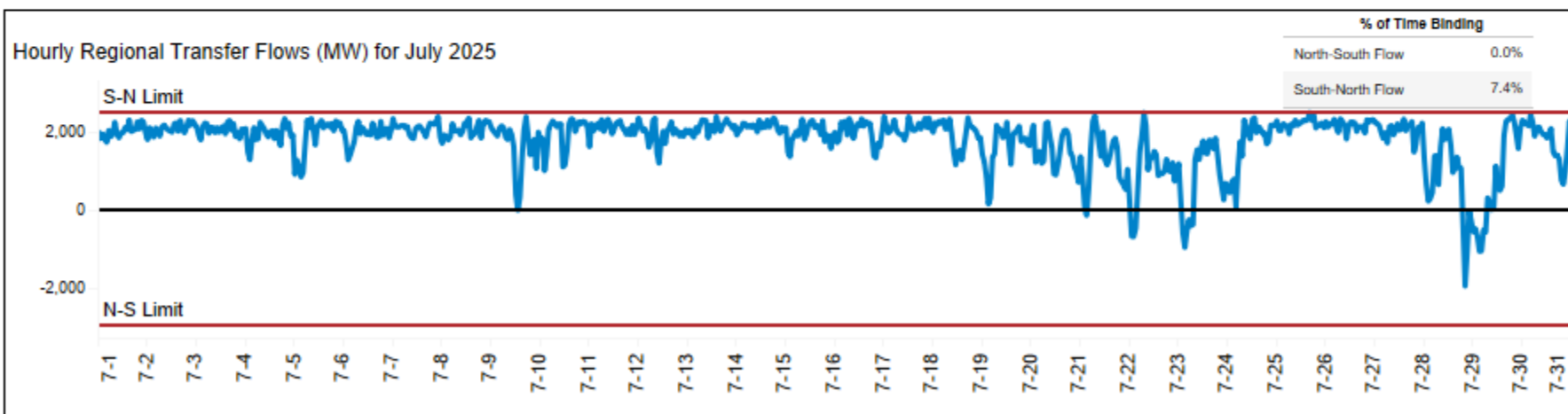
Source: MISO Markets and Operations Analytics Department

Regional Directional Transfer**



Percentage of Time Regional Directional Flow

	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25
North-South Flow	8%	10%	21%	17%	23%	22%	29%	40%	61%	44%	49%	26%	3%
South-North Flow	92%	90%	79%	83%	78%	78%	71%	60%	39%	56%	51%	74%	97%

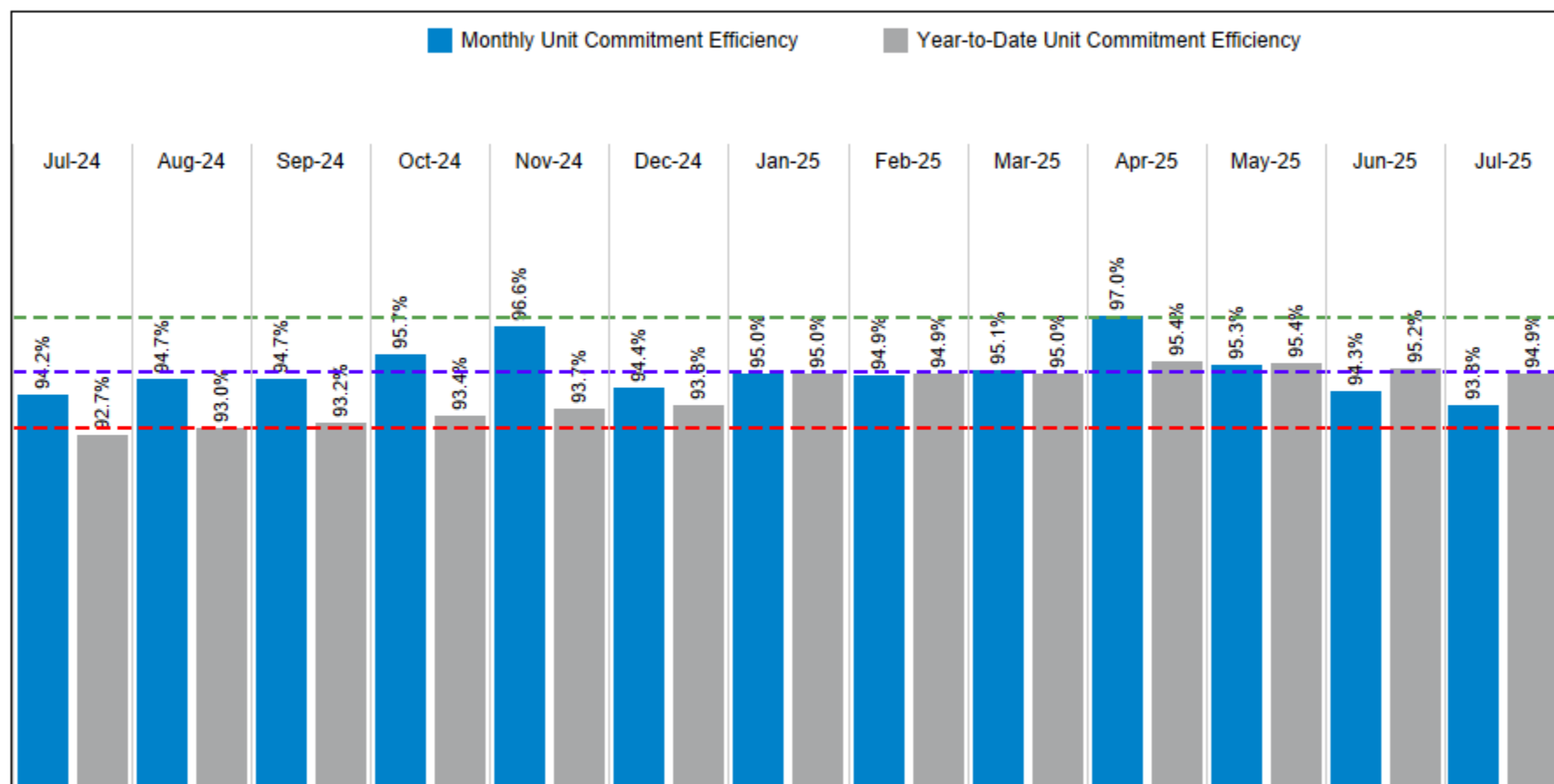


**Regional Directional Transfer between MISO South and Central/North Regions
Source: MISO Markets and Operations Analytics Department

Unit Commitment Efficiency

Effectively commit generation to meet demand obligations and mitigate constraints

H



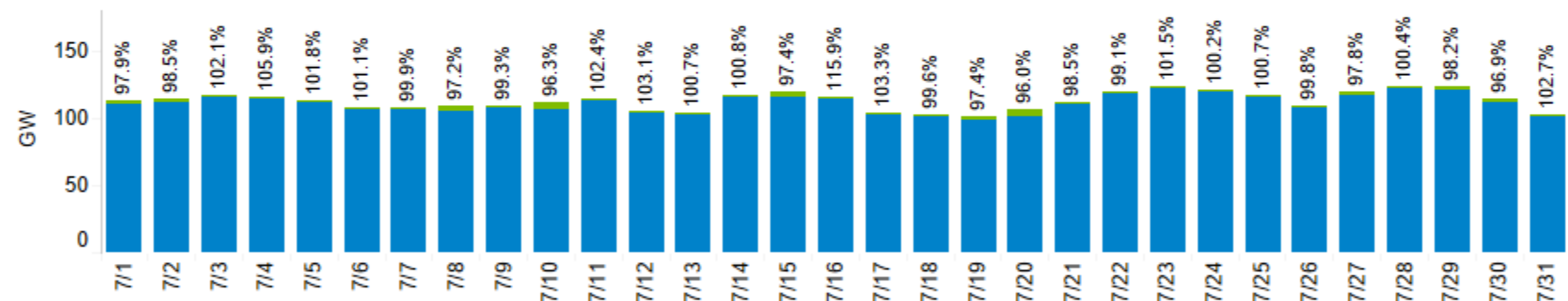
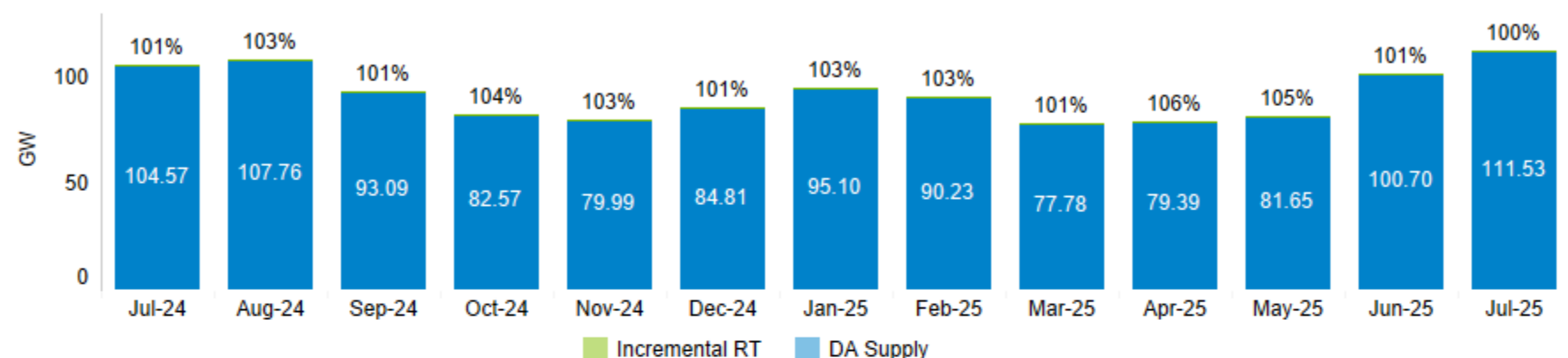
	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25
Actual Cost	\$1,013M	\$974M	\$809M	\$705M	\$682M	\$988M	\$1,311M	\$1,069M	\$819M	\$756M	\$829M	\$1,095M	\$1,427M
Optimal Cost	\$1,005M	\$967M	\$803M	\$701M	\$679M	\$978M	\$1,300M	\$1,061M	\$812M	\$752M	\$822M	\$1,085M	\$1,415M
Sunk Cost	\$878M	\$842M	\$685M	\$595M	\$576M	\$807M	\$1,095M	\$897M	\$673M	\$628M	\$678M	\$913M	\$1,229M

Source: MISO Optimal Dispatch Calculator (ODC)

Unit Commitment Efficiency = $1 - ((\text{Actual cost} - \text{Optimal cost}) / (\text{Actual cost} - \text{Sunk cost}))$



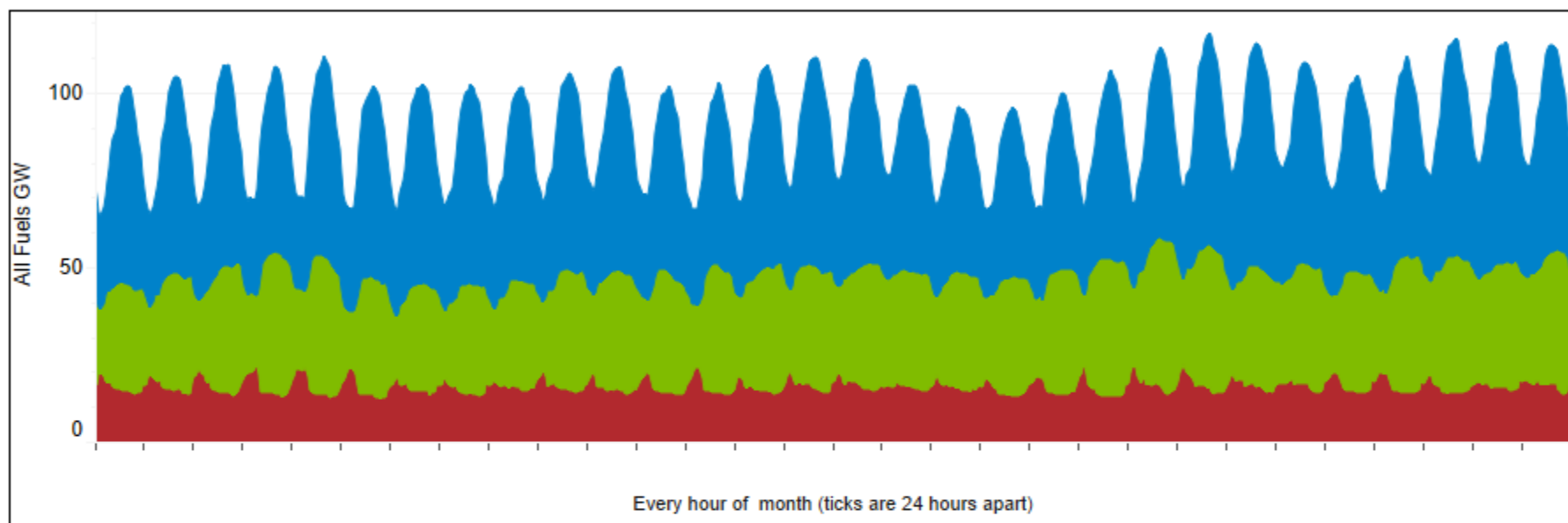
Day-Ahead Supply and Real-Time Load Obligation at the Peak Load Hour



Incremental GW Committed in Real-Time

Day-Ahead Supply is the Day-Ahead Economic Maximum received in Real-Time plus Behind-the-Meter plus Day-Ahead NSI at the Peak Hour
Real-Time Obligation is the Real-Time ICCP Load plus Real-Time Regulation Requirement plus Real-Time Spinning Requirement at the Peak Hour
Real-Time Increment is the Real-Time Obligation less Day-Ahead Supply at the Peak Hour
Percents calculated as Day-Ahead Supply divided by Real-Time Obligation

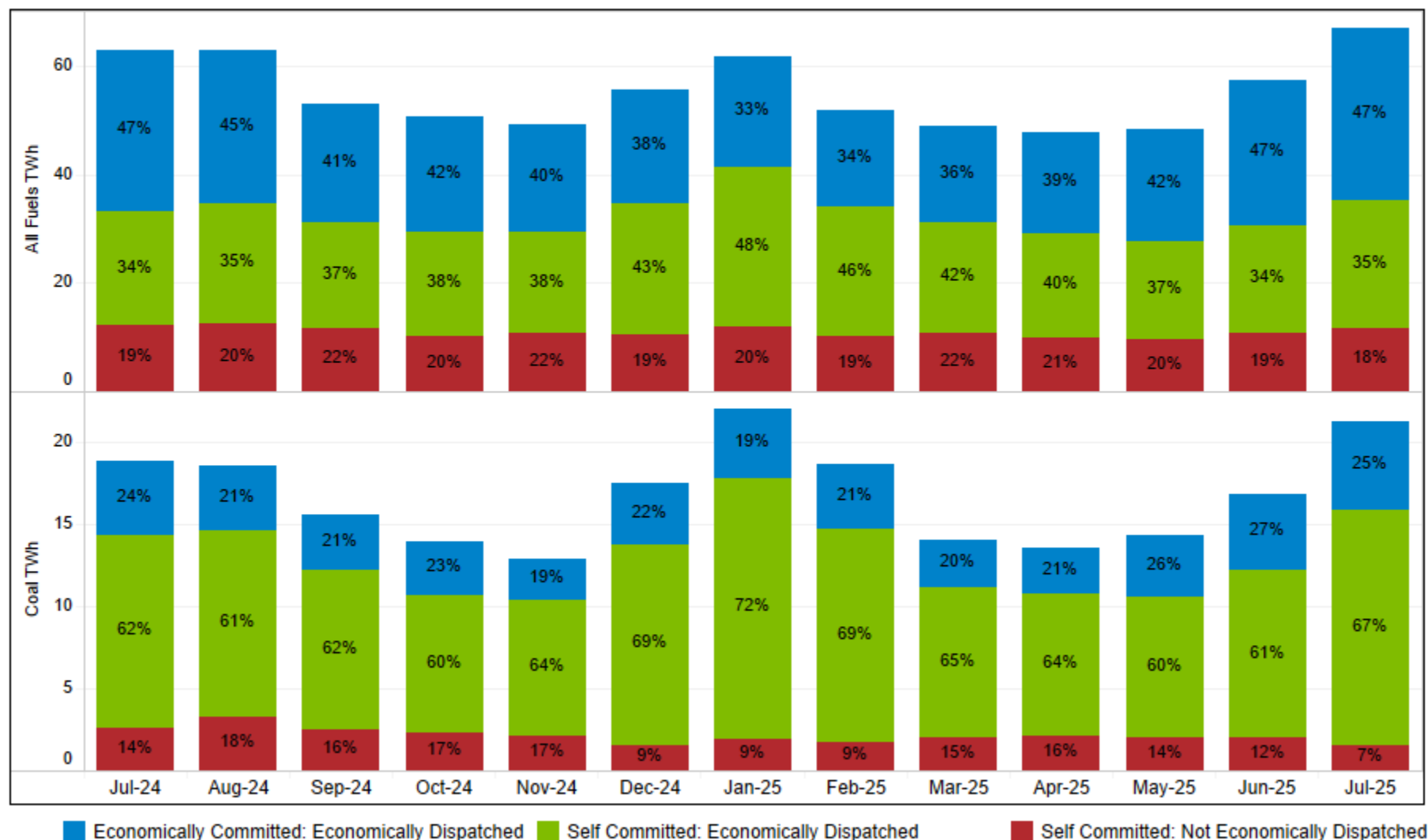
Self Committed and Economically Dispatched Energy - July 2025



	All Fuels		Coal		Gas	
	TWh	%	TWh	%	TWh	%
Economically Committed: Economically Dispatched	31.7	47%	5.4	25%	22.0	77%
Self Committed: Economically Dispatched	23.5	35%	14.3	67%	5.4	19%
Self Committed: Not Economically Dispatched	11.7	18%	1.5	7%	1.0	4%
Grand Total	66.9	100%	21.2	100%	28.4	100%

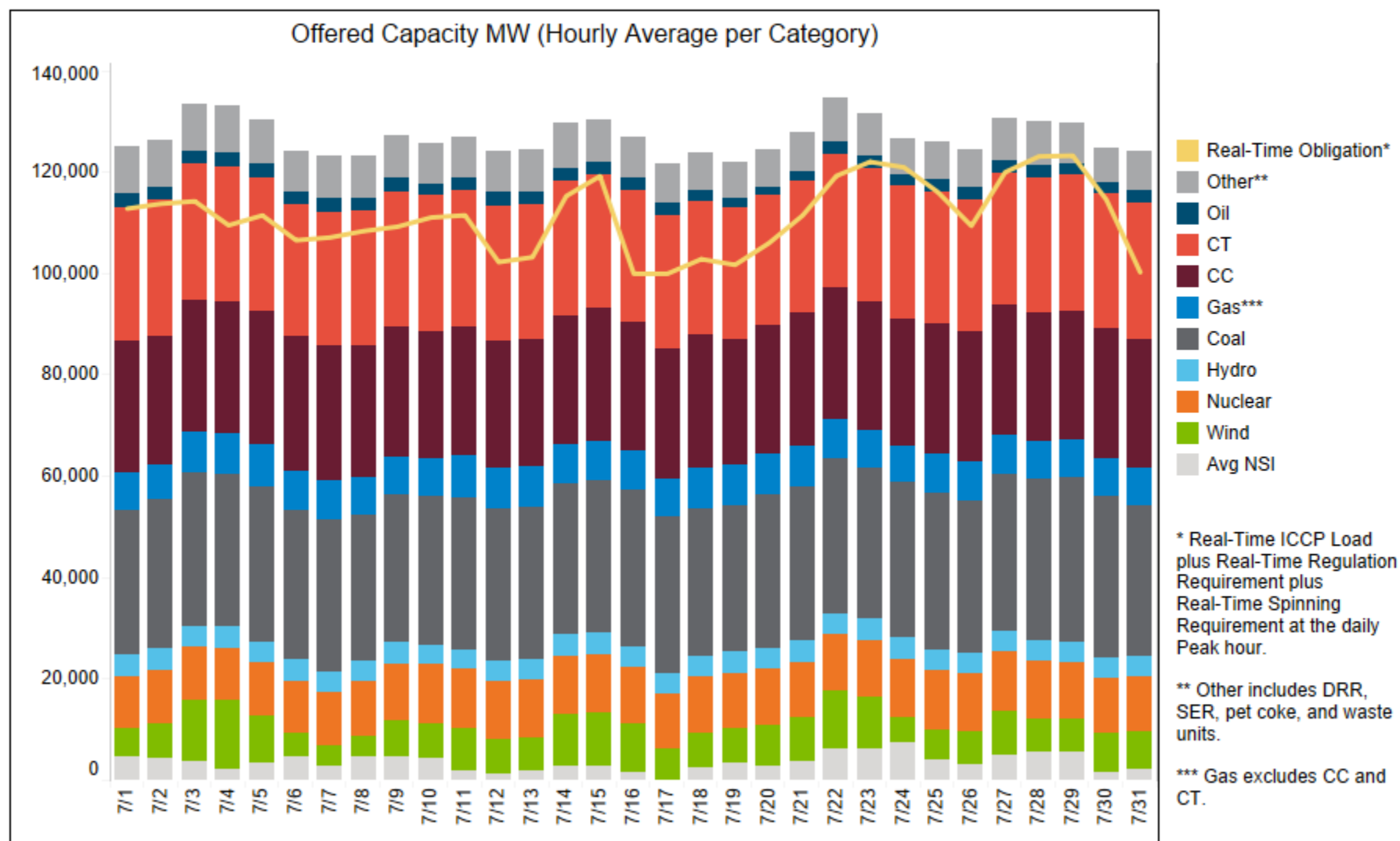
	Economically Committed: Economically Dispatched	Generation committed by MISO and dispatched on economic offers.
	Self Committed: Economically Dispatched	Generation that is self-committed, but Resource Owners allow MISO to dispatch economically after the self-schedule portion of their resource offer is satisfied. Self-commitments can be used to manage local reliability, operational constraints, and fuel contract constraints.
	Self Committed: Not Economically Dispatched	Energy from self-committed generation produced at its minimum level or is block-loaded and cannot be dispatched. Block Loaded energy is not necessarily uneconomic, but MISO has no ability to dispatch it based on economics.

Monthly Trend - Self Committed and Economically Dispatched Energy



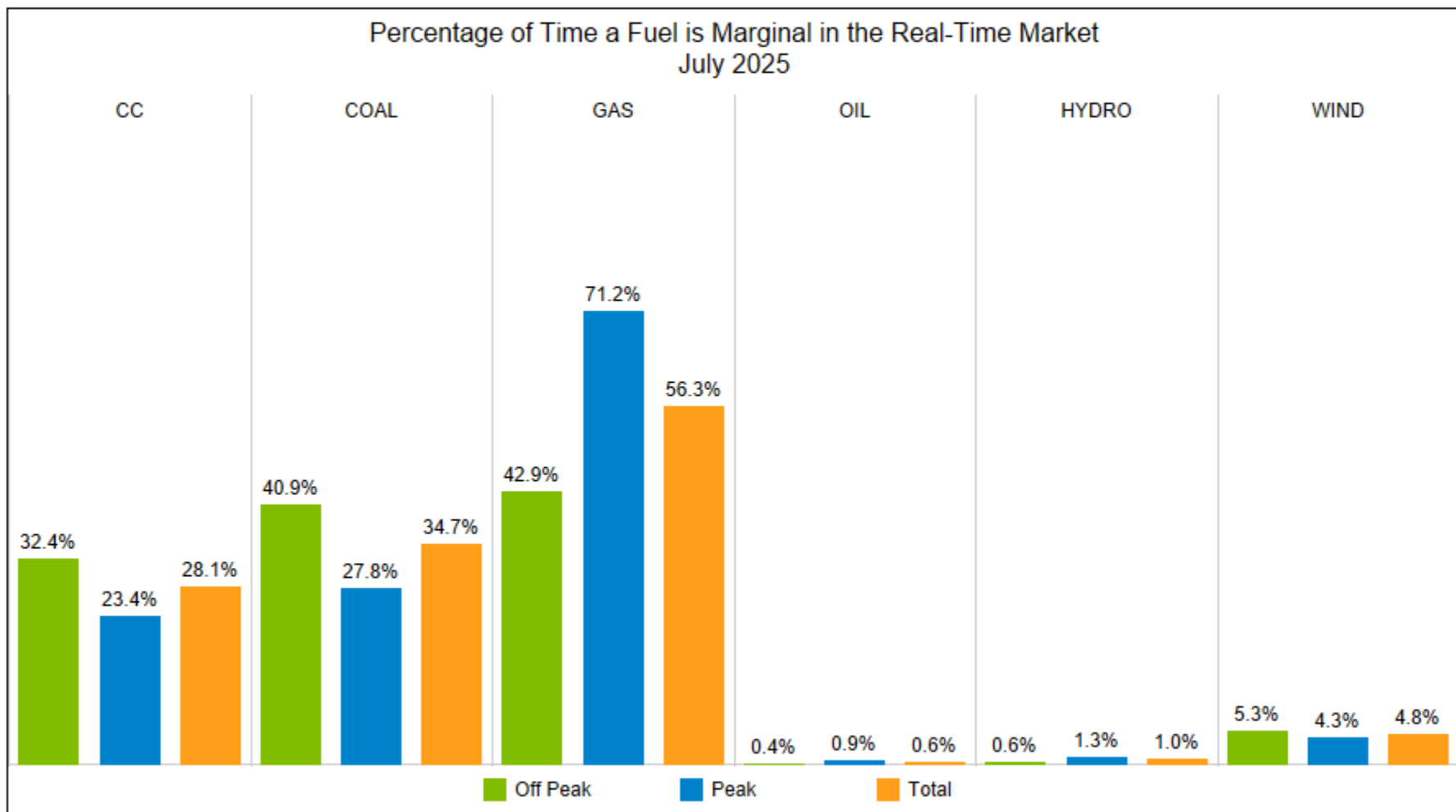
Source: MISO Market and Operations Analytics Department

Offered Capacity and Real-Time Peak Load Obligation



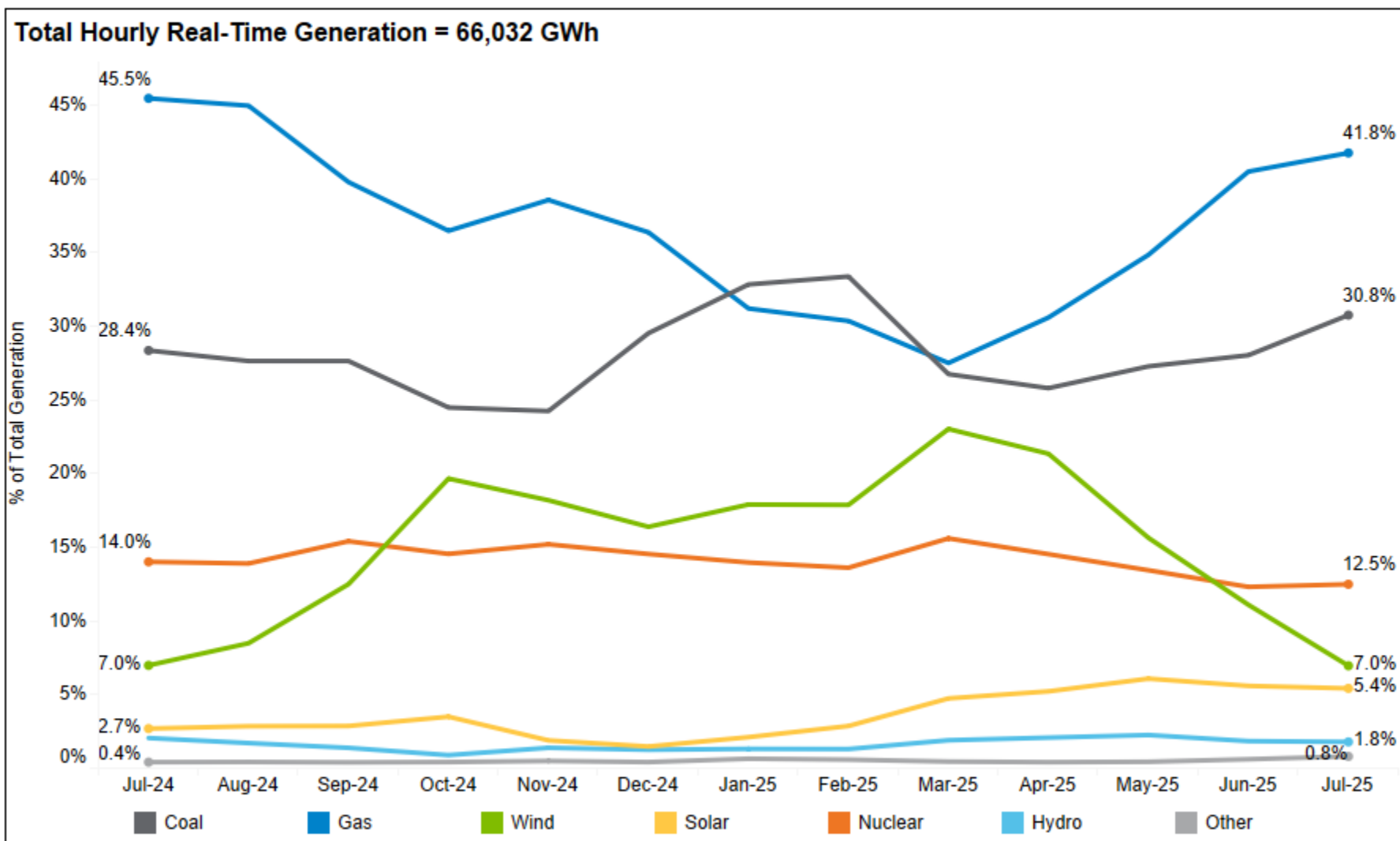
Source: MISO Market and Operations Analytics Department

Marginal Fuel



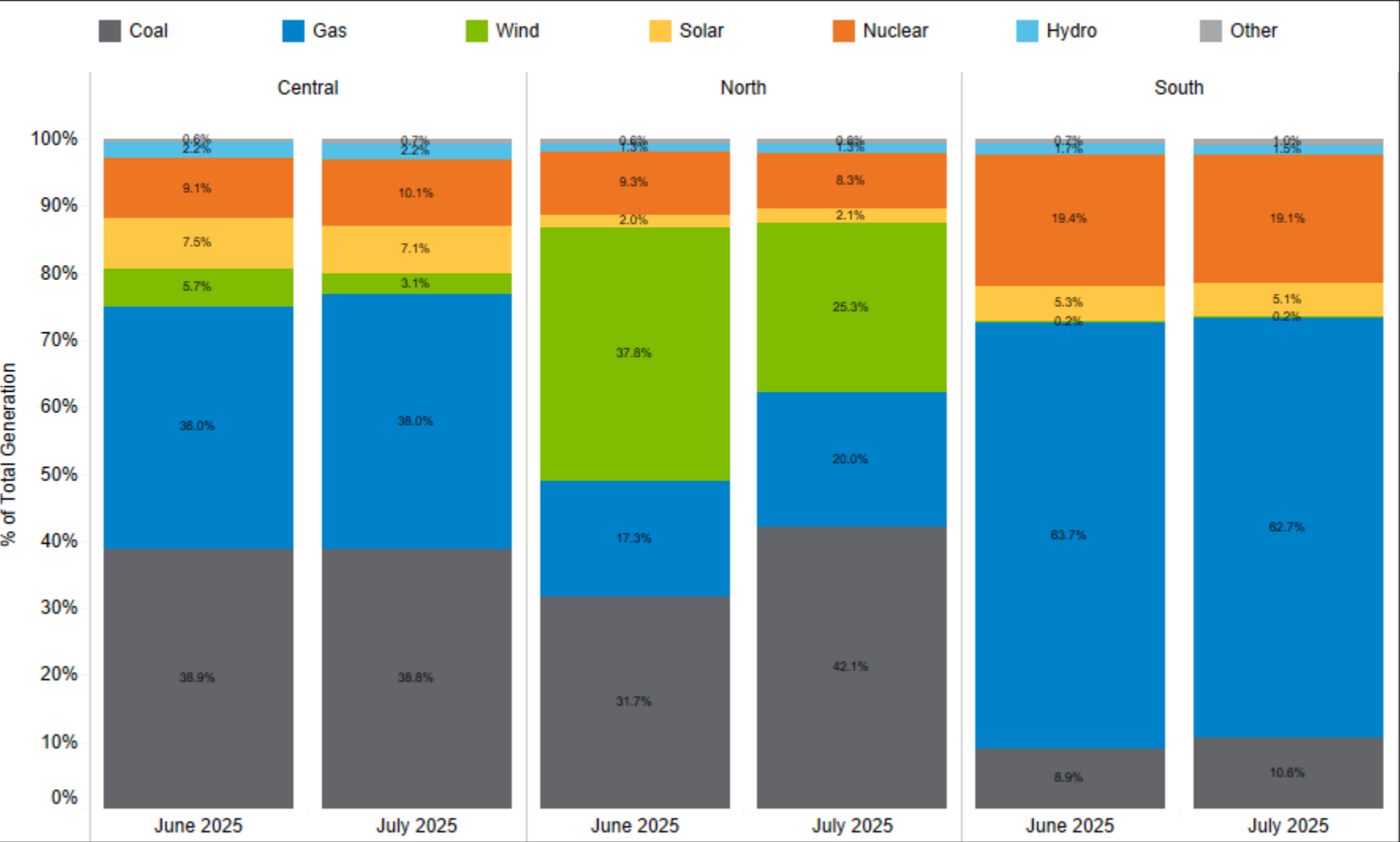
Note: Binding transmission constraints can produce instances where more than one unit is marginal in the system. Consequently, more than one fuel may be on the margin; and since each marginal unit is included in the analysis, the percentage may sum to more than 100%.

Real-Time Generation Fuel Mix



Based on hourly unit level state estimator data
Other includes: Battery, Oil, Pet Coke, Waste and Other fuels
Source: MISO Market and Operations Analytics Department

Real-Time Generation Fuel Mix by Region



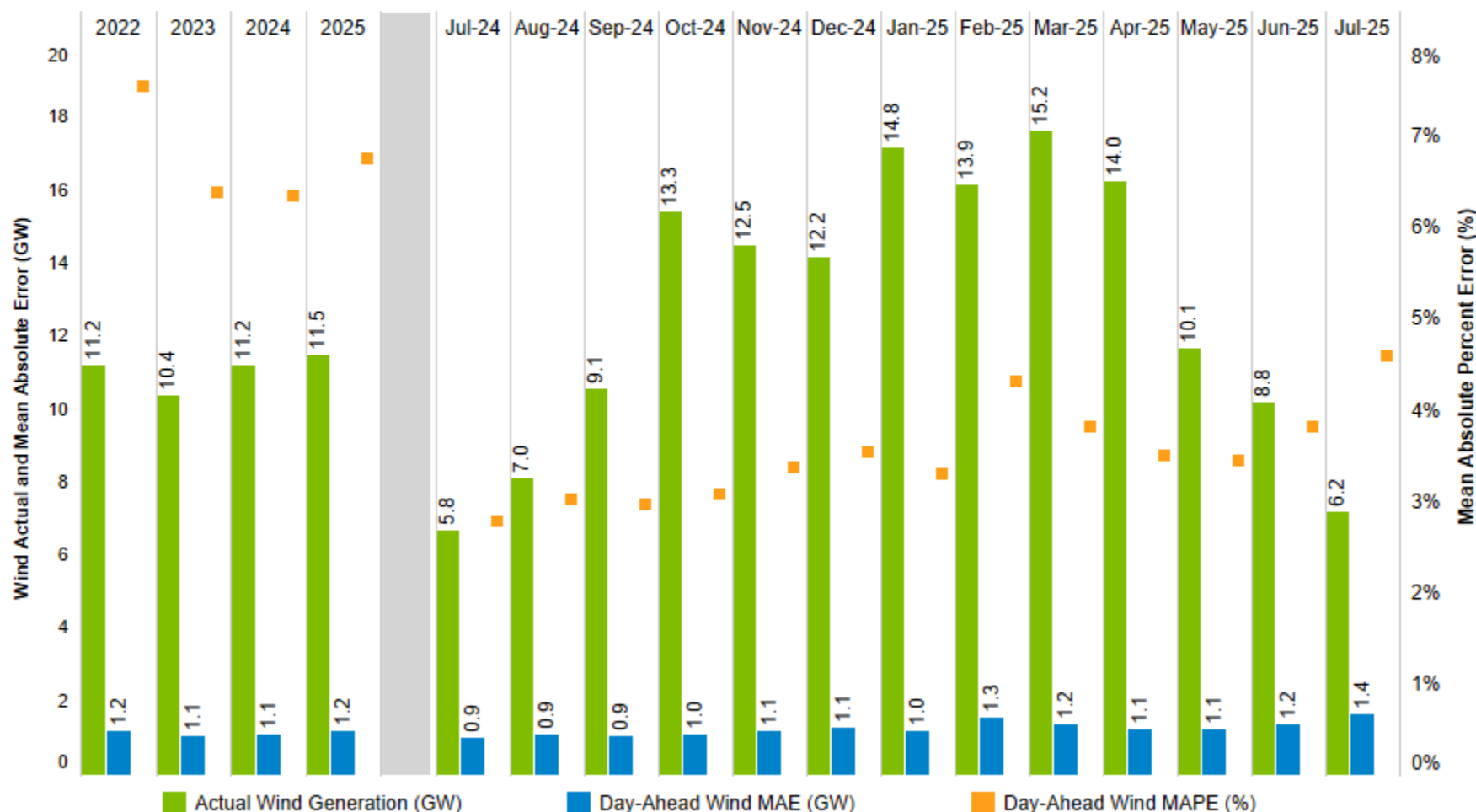
Based on hourly unit level state estimator data
Other includes: Battery, Oil, Pet Coke, Waste and Other fuels
Source: MISO Market and Operations Analytics Department



Monthly Day-Ahead Wind Forecast Performance: Mean Absolute Error (MAE) and Mean Absolute Percent Error (MAPE)

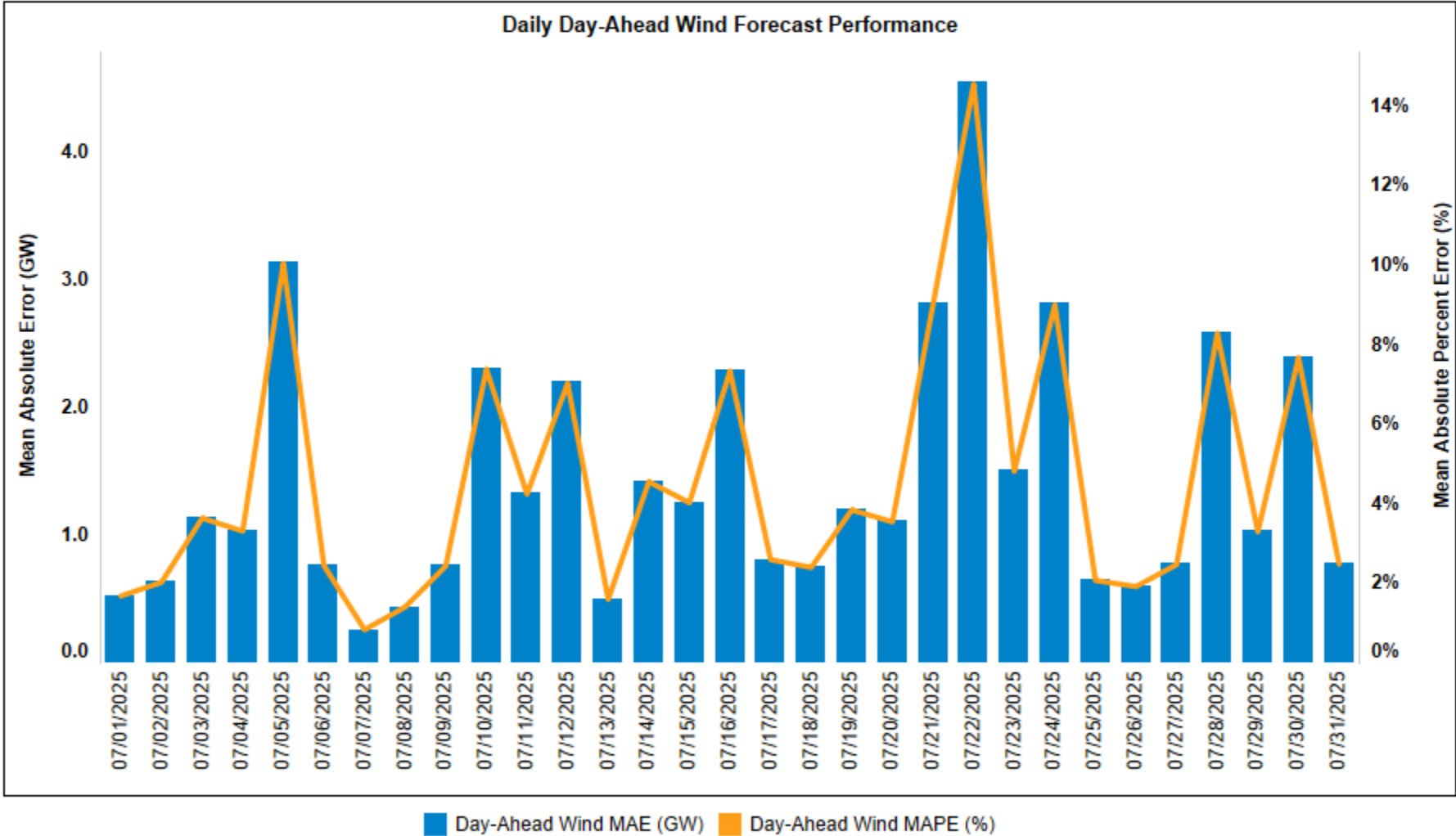
K

Monthly Day-Ahead Wind Forecast Performance



Source: MISO Operations Risk Management

Daily Day-Ahead Wind Forecast Performance: Mean Absolute Error (MAE) and Mean Absolute Percent Error (MAPE)

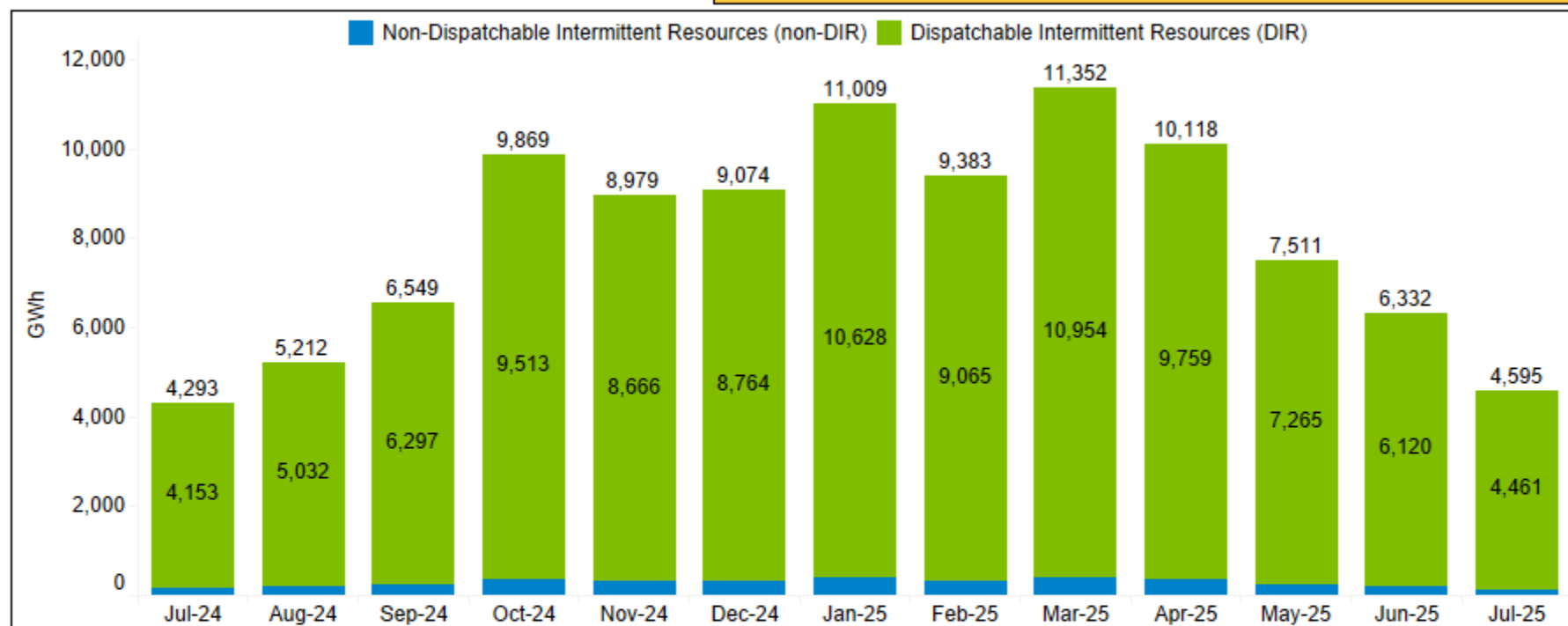


Source: MISO Operations Risk Management

Monthly Wind Energy Generation

As of 06/04/2025

Registered Wind Capacity = 31,650 MW; Inservice Wind Capacity = 31,315 MW
Registered DIR Capacity = 30,122 MW; Inservice DIR Capacity = 29,787 MW



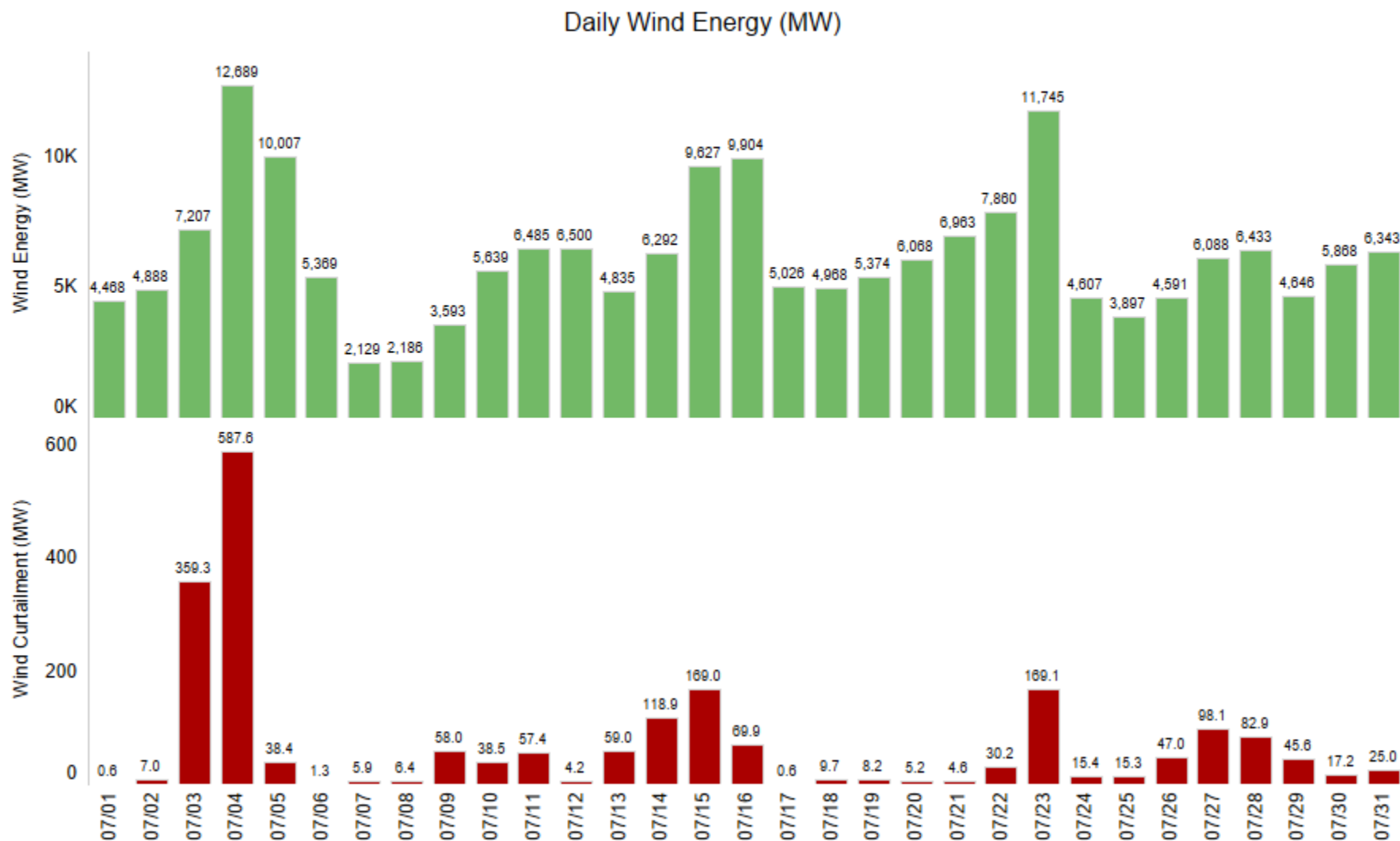
	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25
Peak Wind Date and Hour Ending	7/1 23	8/6 4	9/12 24	10/30 2	11/20 18	12/4 11	1/28 21	2/28 22	3/23 15	4/28 19	5/16 21	6/21 15	7/5 1
Peak hourly wind output (MW)	18,465	15,418	16,944	22,683	21,272	24,044	25,218	24,646	24,172	23,582	22,803	21,086	15,404
Peak wind output as % of MISO load in that hour	24.0%	21.2%	24.2%	36.1%	29.0%	28.7%	31.2%	34.1%	34.6%	28.6%	28.6%	19.3%	19.2%
Wind Energy as a percent of MISO Energy	7.3%	8.8%	12.8%	19.9%	18.4%	16.3%	18.2%	18.1%	23.2%	21.5%	15.6%	11.3%	7.3%
DIR dispatch below Max as % of avail. DIR	2.1%	2.7%	4.9%	4.0%	3.4%	2.3%	3.3%	2.0%	3.1%	4.3%	3.3%	3.3%	1.3%

*Hourly State Estimator data

Source: MISO Market and Operations Analytics Department

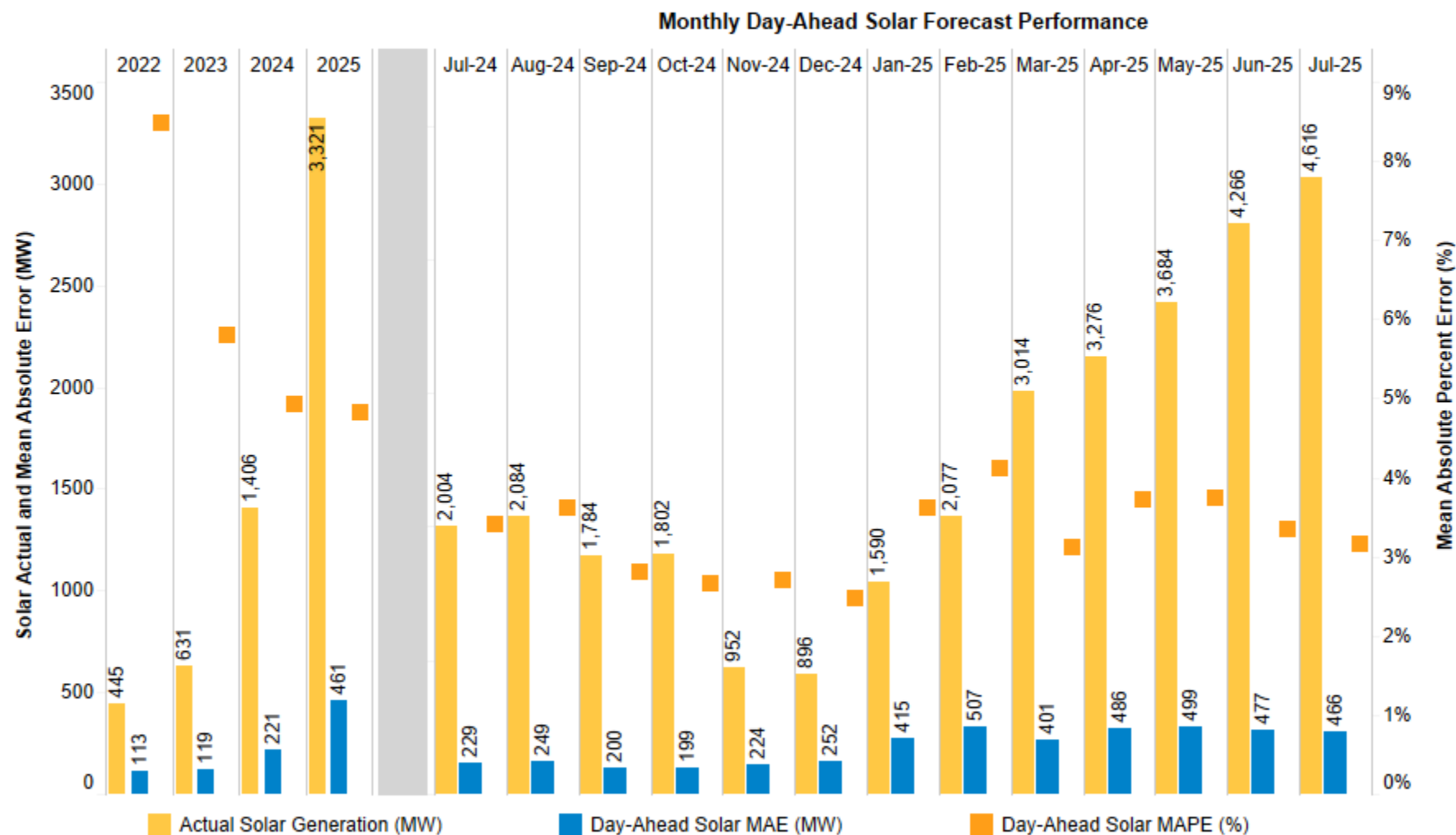


Daily Average Wind Energy and Curtailment



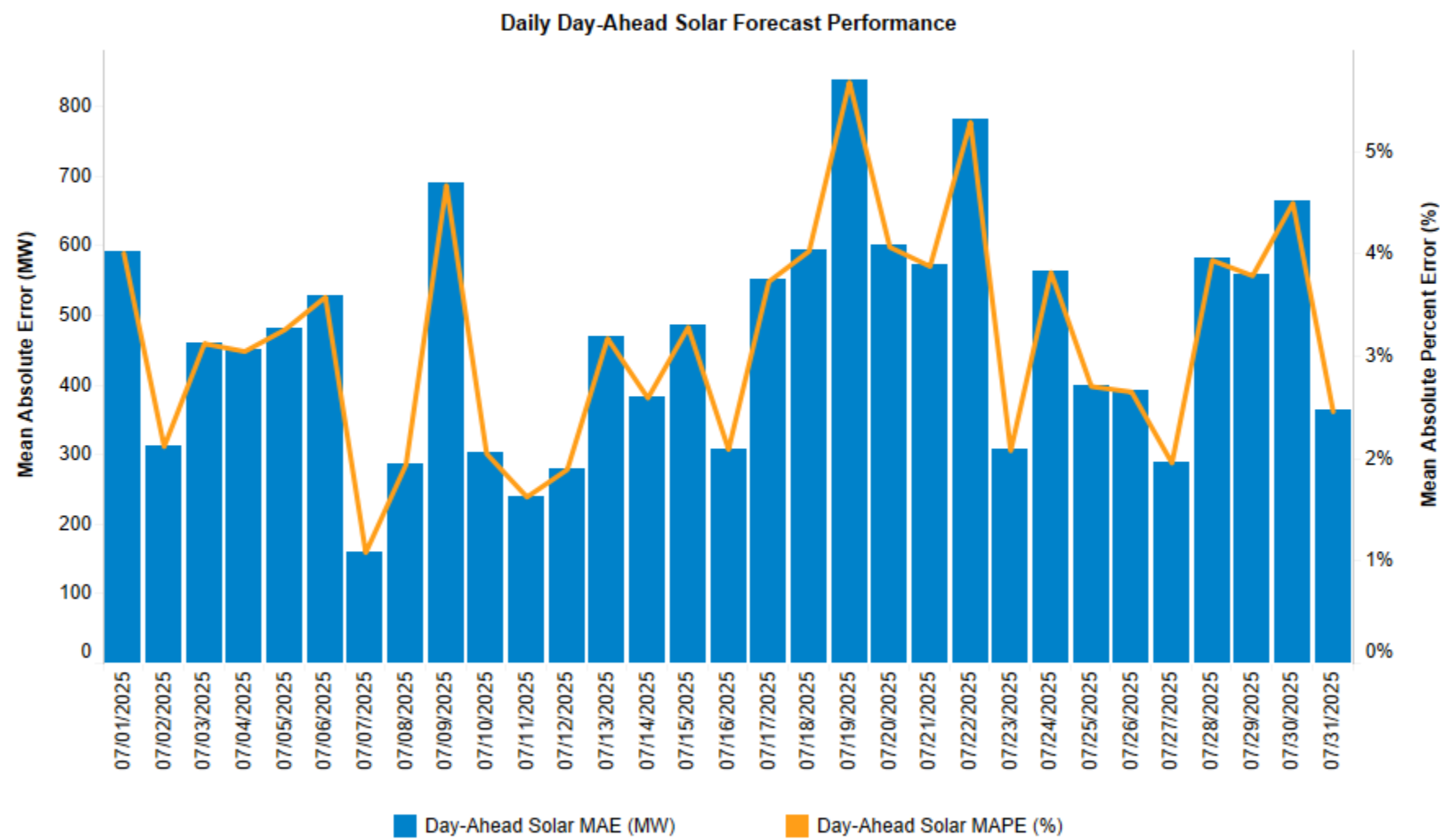
Source: MISO Market and Operations Analytics Department

Monthly Day-Ahead Solar Forecast Performance: Mean Absolute Error (MAE) and Mean Absolute Percent Error (MAPE)



Source: MISO Operations Risk Management

Daily Day-Ahead Solar Forecast Performance: Mean Absolute Error (MAE) and Mean Absolute Percent Error (MAPE)

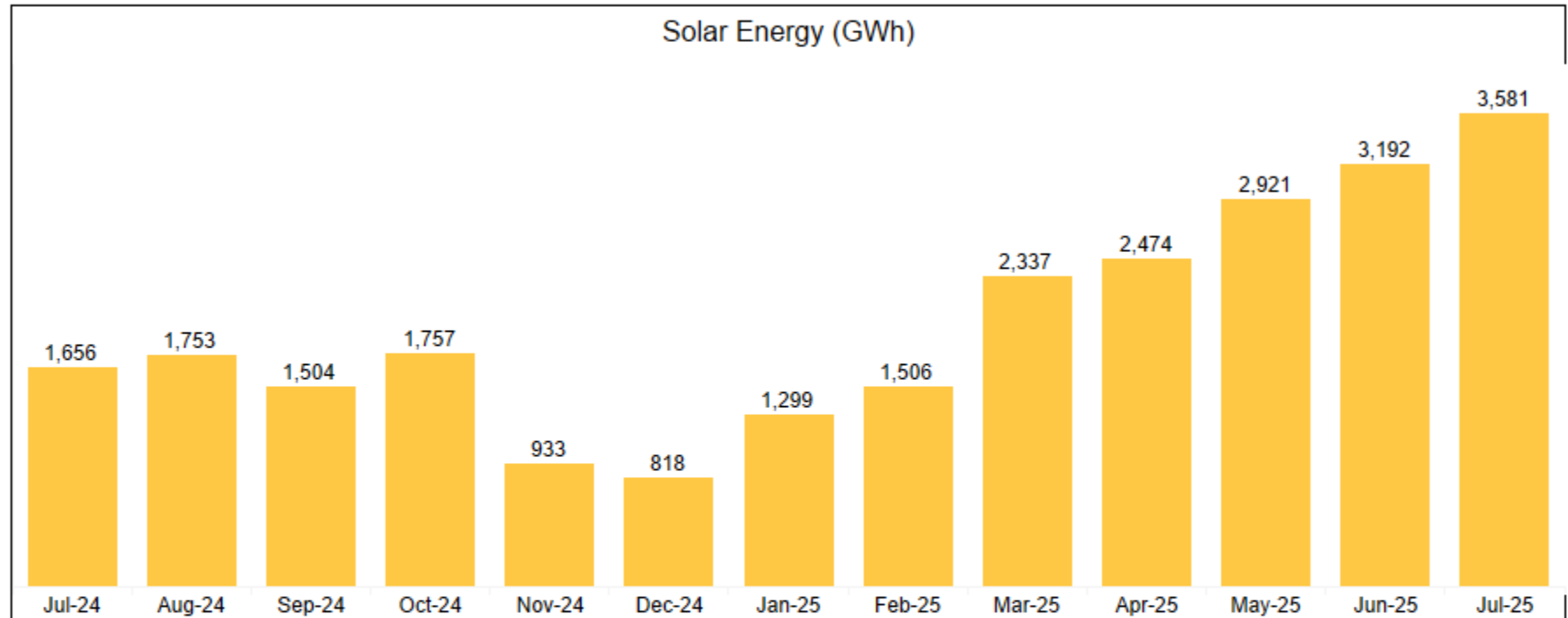


Source: MISO Operations Risk Management

Monthly Solar Energy

As of 06/04/2025
 Registered Solar Capacity = 19,131 MW; Inservice Solar Capacity = 14,112 MW
 Registered DIR Capacity = 18,959 MW; Inservice DIR Capacity = 13,940 MW

Solar Energy (GWh)

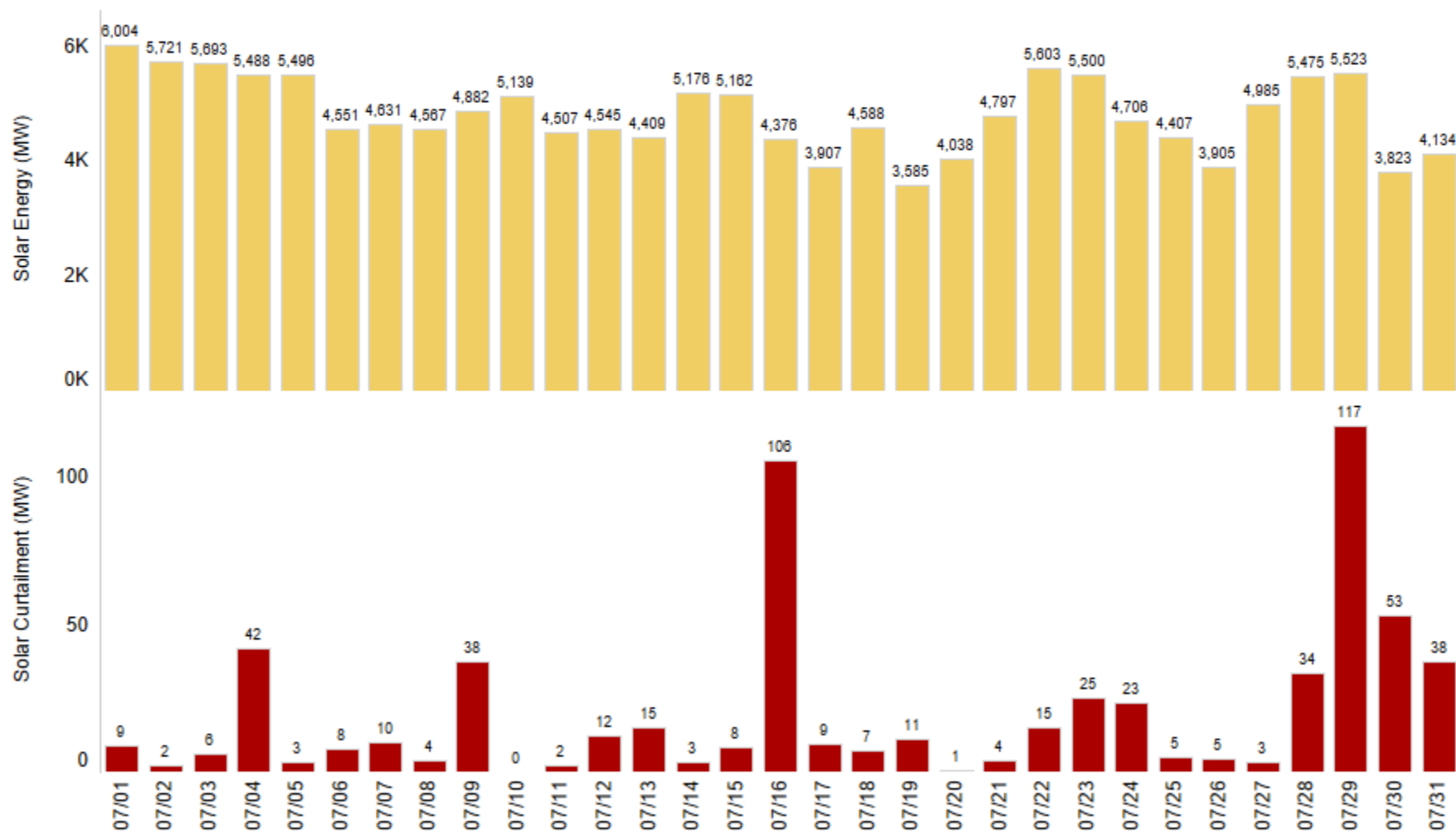


Peak Solar Date and Hour Ending	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25
	7/13 12	8/22 12	9/26 12	10/16 16	11/12 16	12/21 12	1/20 12	2/21 12	3/22 15	4/16 14	5/31 13	6/22 11	7/1 12
Peak Hour Solar Output (MW)	6,168	6,835	7,054	7,919	6,813	6,898	8,308	11,360	12,061	12,342	13,366	12,872	13,129
Peak Solar Output as a % of MISO Load in that hour	6.5%	8.3%	9.1%	11.5%	9.6%	8.7%	8.4%	12.4%	18.8%	18.0%	19.2%	12.9%	13.3%
Solar Energy as a % of MISO Energy	3.2%	3.8%	3.5%	4.7%	2.6%	2.0%	2.6%	3.5%	6.0%	5.4%	6.0%	6.0%	5.5%
DIR Dispatch below MAX as a % of avail. DIR	-0.5%	-0.5%	0.4%	-0.3%	-0.6%	-3.1%	-1.9%	0.1%	1.1%	0.5%	-0.1%	-0.1%	-0.4%

*Hourly State Estimator data
 Source: MISO Forecast Department

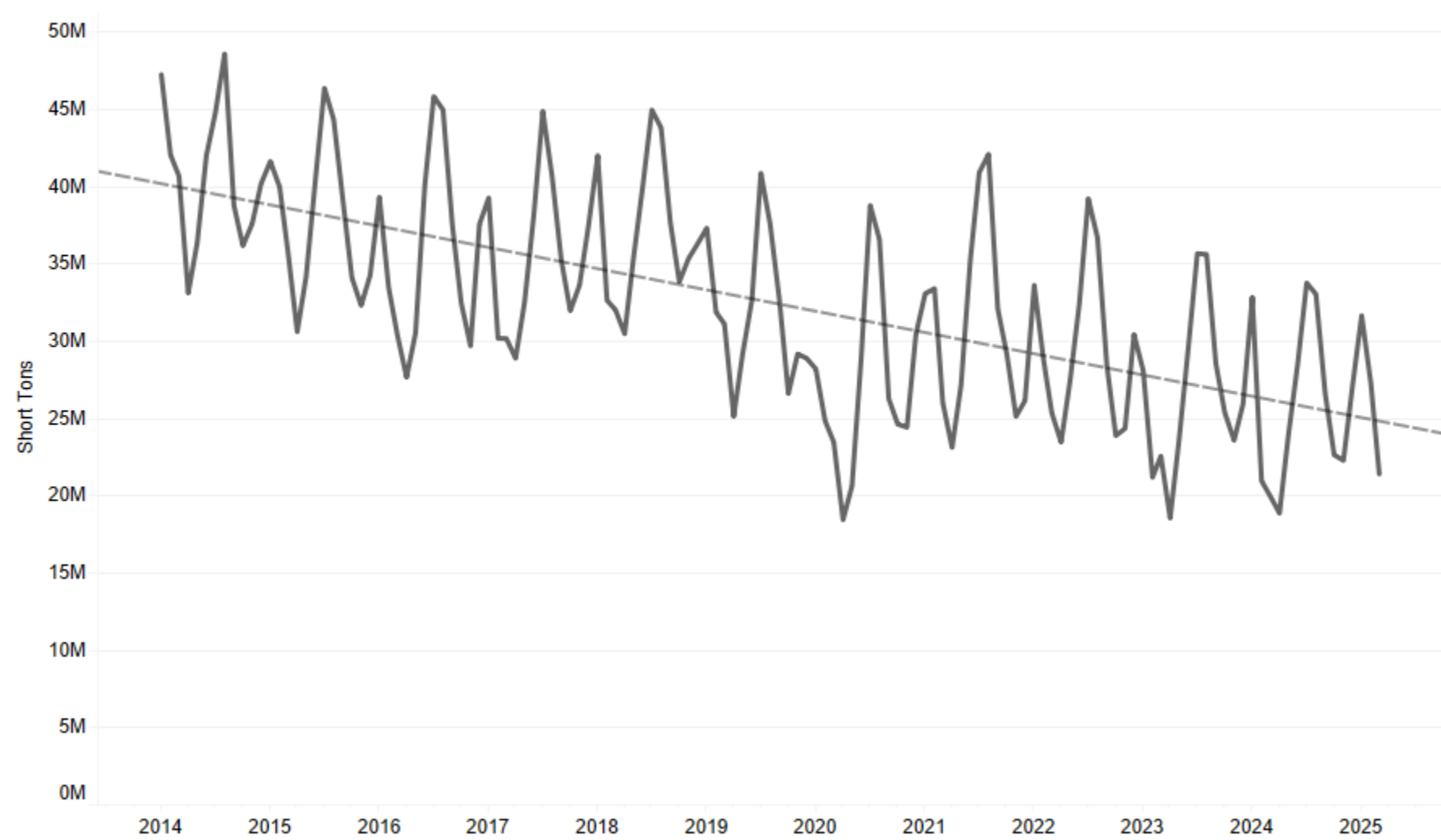
Daily Average Solar Energy and Curtailment

Daily Solar Energy (MW)



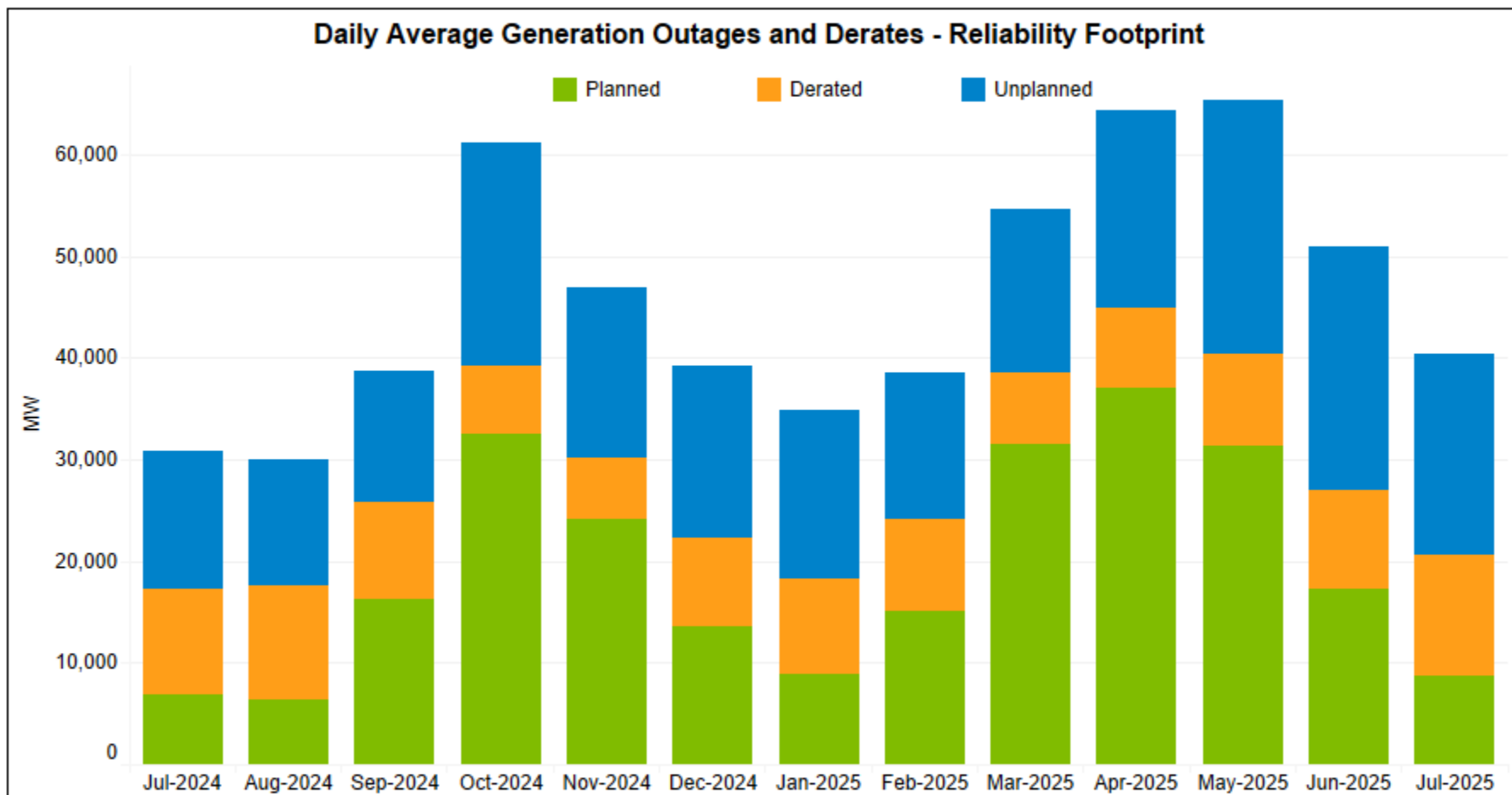
Source: MISO Market and Operations Analytics Department

Carbon Emissions



Data Source: EPA emissions through March 2025 and EPA EIA-860 2023
Emissions generated from MISO generators and does not account for volume of imports or exports
One Short Ton = 2000 lbs

Generation Outages and Derates



Notes:

•Unplanned Outages include Emergency, Forced, and Urgent

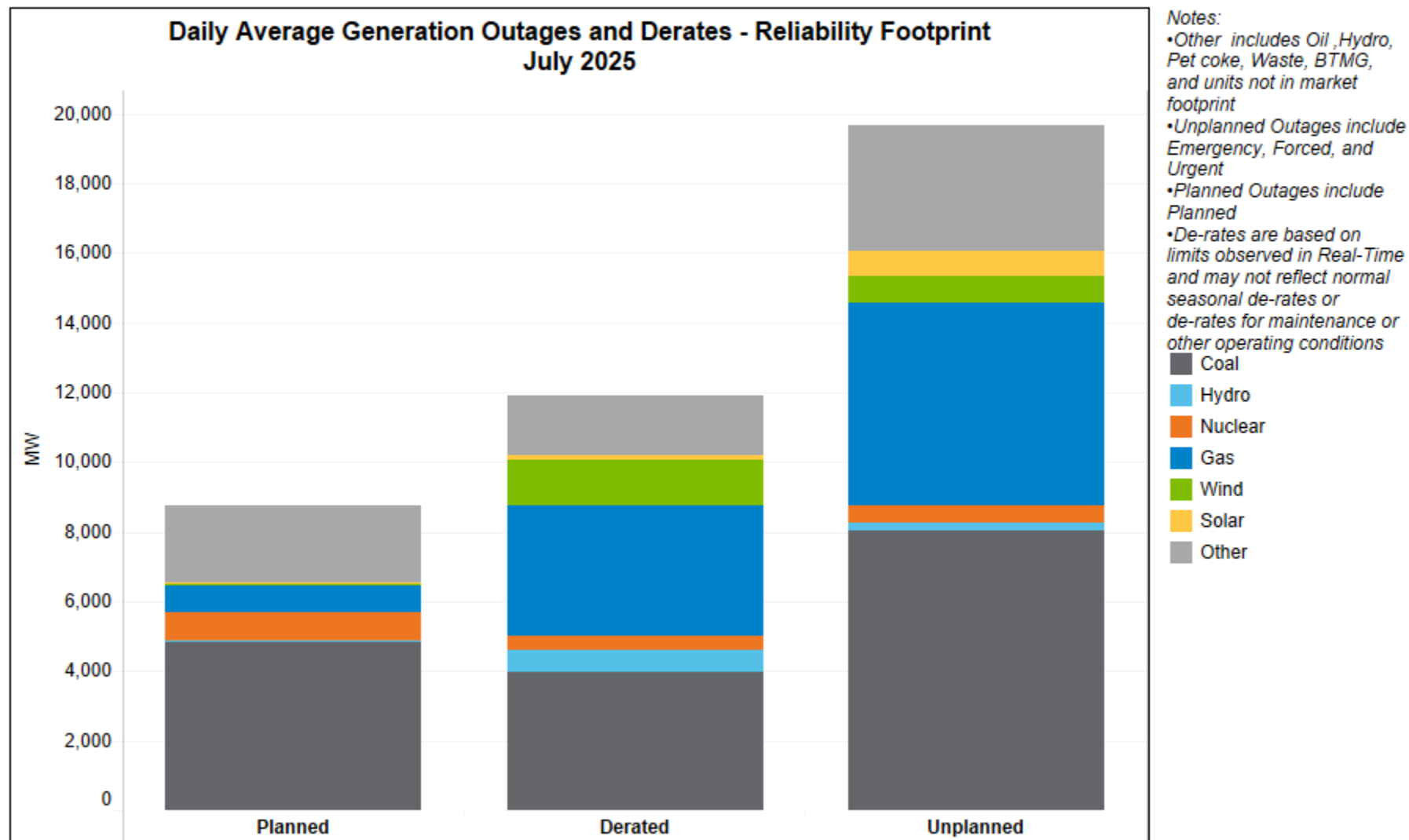
•Planned Outages include Planned

•De-rates are based on limits observed in Real-Time and may not reflect normal seasonal de-rates or de-rates for maintenance or other operating conditions

Outage data is "point in time" and can change; the chart reflects the data as it resided in the system on the date of extraction

Source: MISO CROW Outage Scheduler

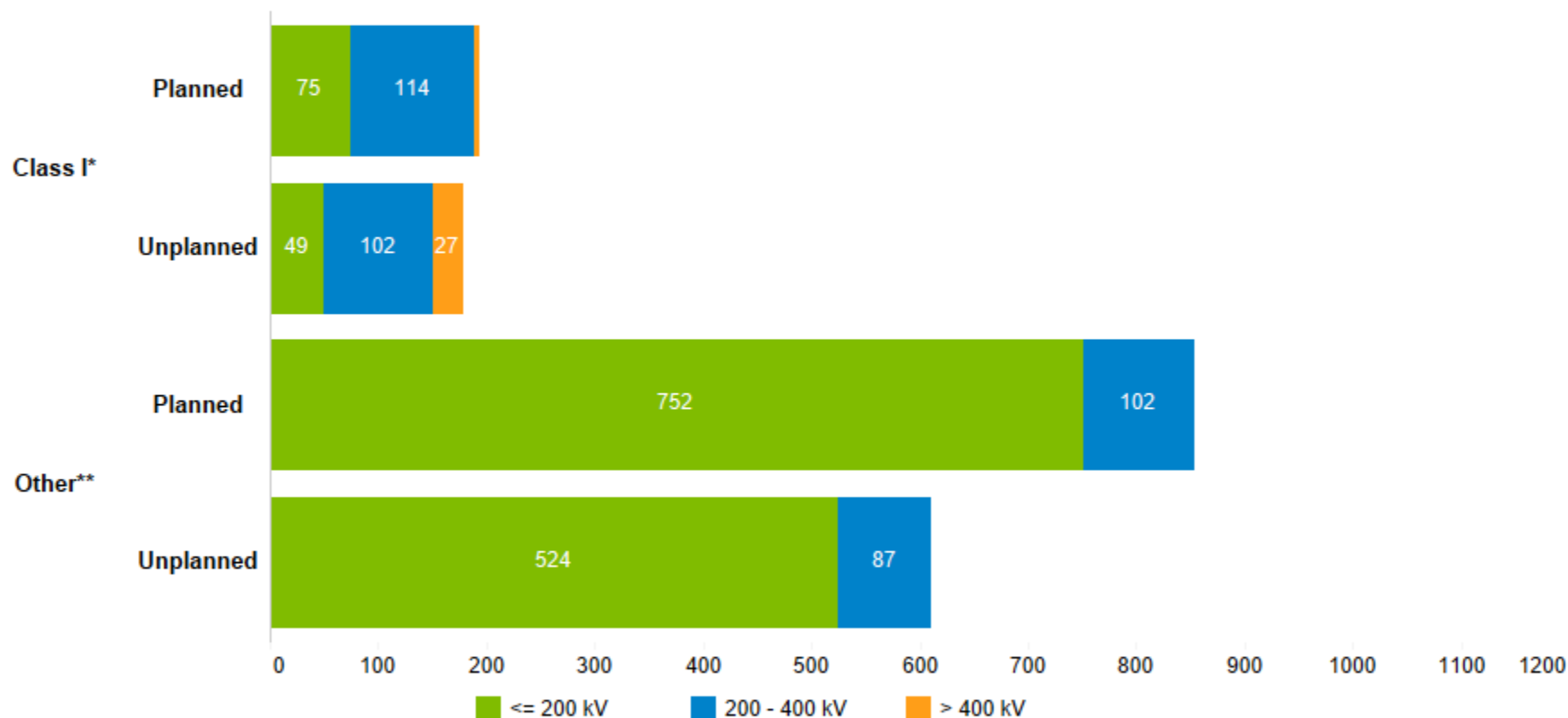
Generation Outages by Fuel



Outage data is "point in time" and can change; the chart reflects the data as it resided in the system on the date of extraction
Source: MISO CROW Outage Scheduler

Transmission Outages

Count of Transmission Outage Requests
July 2025



Notes:

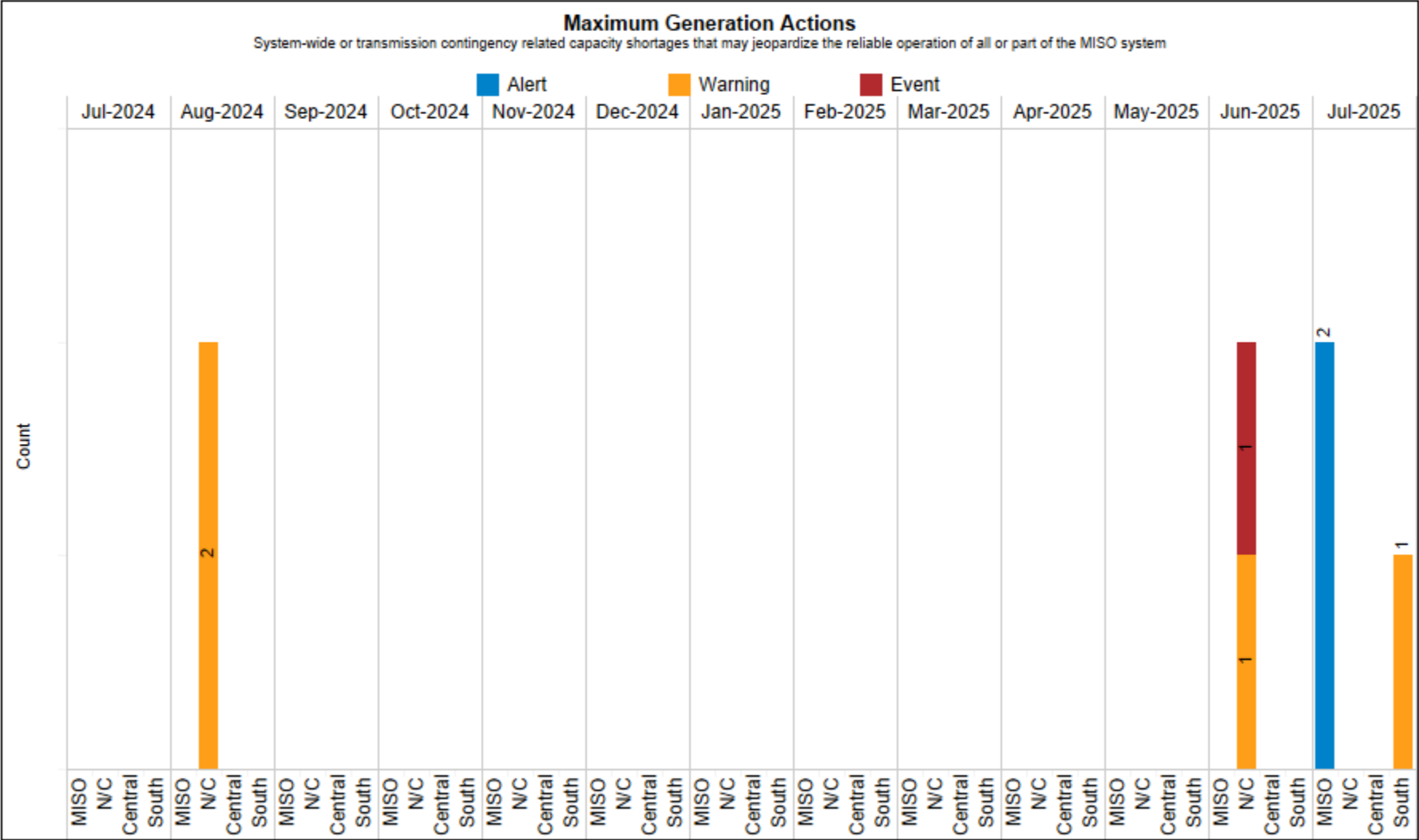
- Class 1 is any facility which has a reliability or market impact on transmission system operations
- Other is any facility which does NOT have a reliability or market impact on transmission system operations
- Unplanned Outages include Emergency, Forced, Discretionary and Urgent
- Planned Outages include Planned, Opportunity

MISO Inadvertent Balance

Month/Year	Net	On-Peak	Off-Peak
6/1/2024	-21,123	-10,382	-10,741
7/1/2024	-33,949	-12,863	-21,086
8/1/2024	-39,602	-15,448	-24,154
9/1/2024	-79,156	-36,769	-42,387
10/1/2024	-37,833	-17,446	-20,387
11/1/2024	-5,440	-2,237	-3,203
12/1/2024	-1,006	624	-1,630
1/1/2025	11,913	7,358	4,555
2/1/2025			
3/1/2025			
4/1/2025			
5/1/2025			
6/1/2025			
7/1/2025			
Running Total from 2009	-95,937	-88,521	-7,416

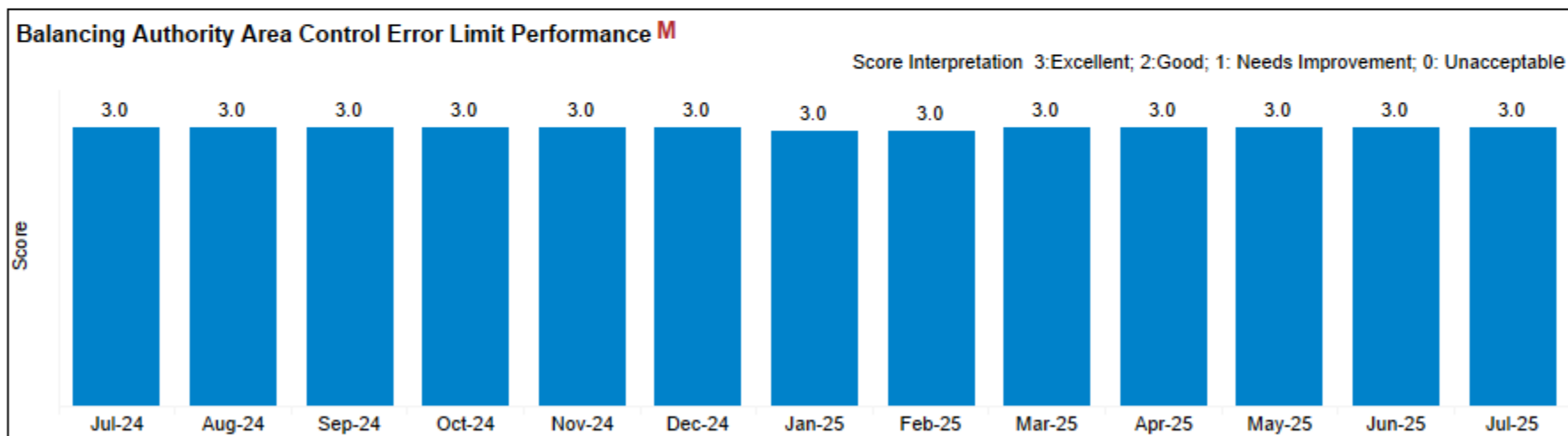
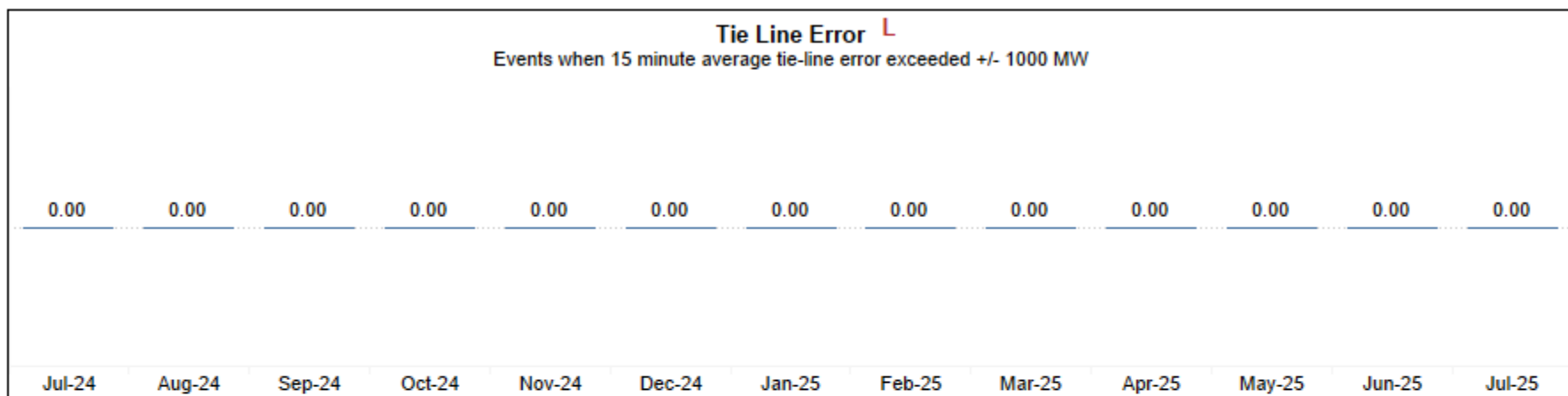
Source: NERC Tool (As of May 10, 2025)

Generation Notifications



* Alerts – forecasting specific emergency situations in a future time-frame
* Warnings – experiencing initial stages of an emergency situation and taking action
* Events – experiencing an emergency situation and taking action

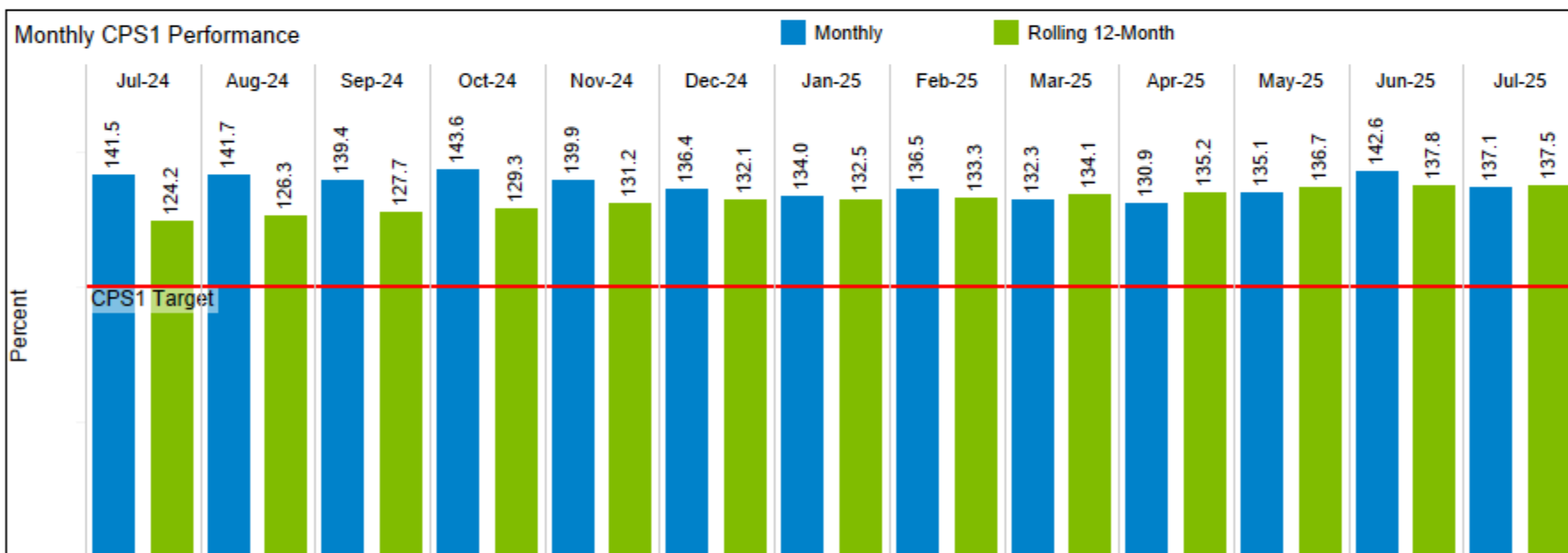
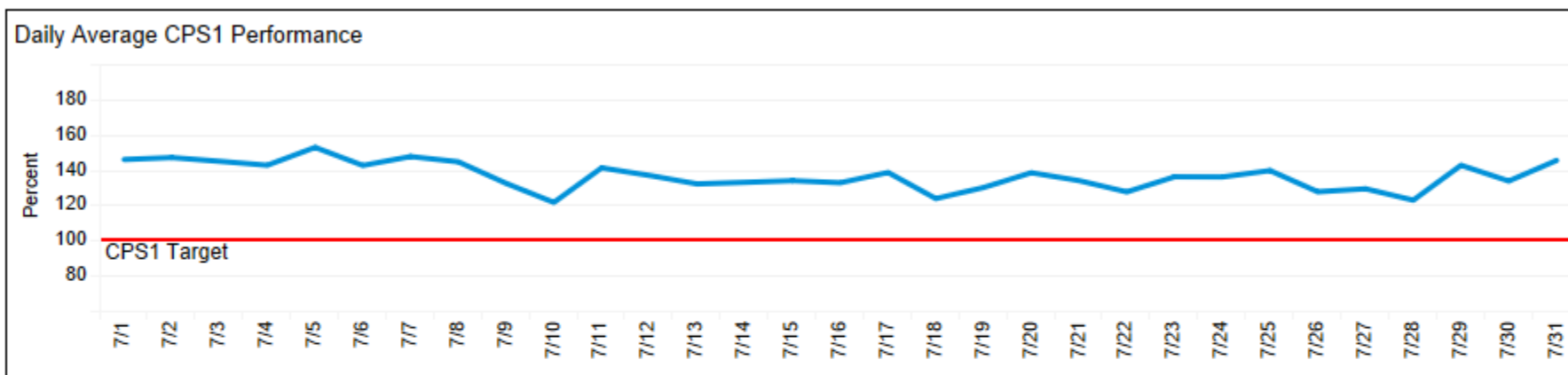
Tie Line and BAAL Performance



The Balancing Authority Area Control Error Limit (BAAL) measures control performance over the short-term. Exceeding BAAL for a continuous time period greater than 30 minutes constitutes a non-compliant event. The daily MISO BAAL performance rating is the lowest scored incident of the day.

CPS1 Performance

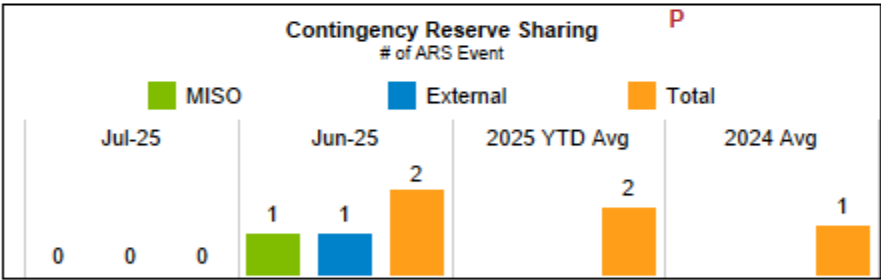
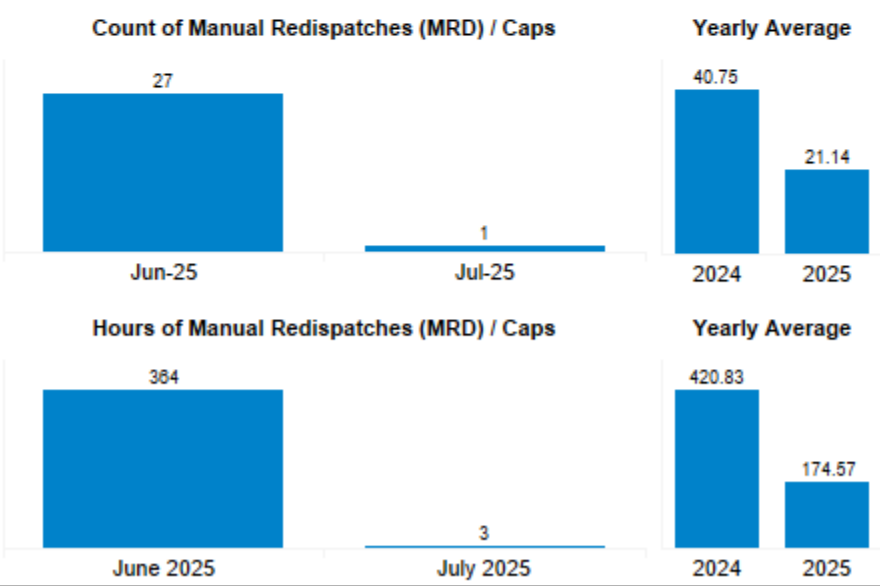
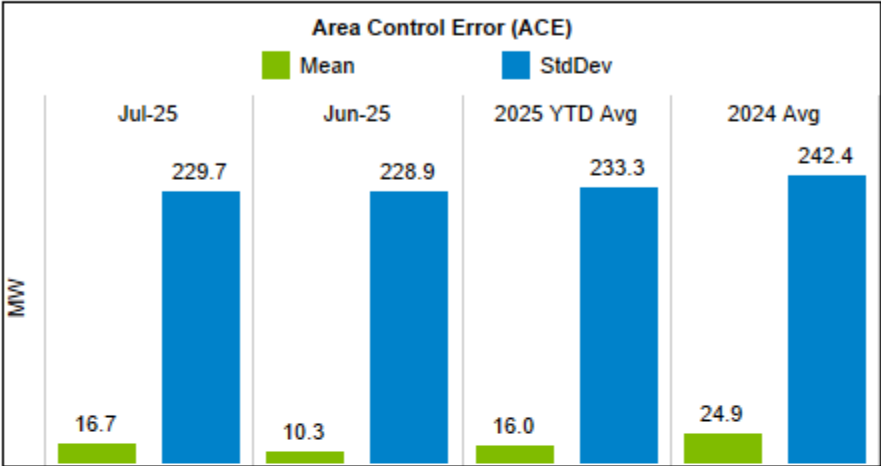
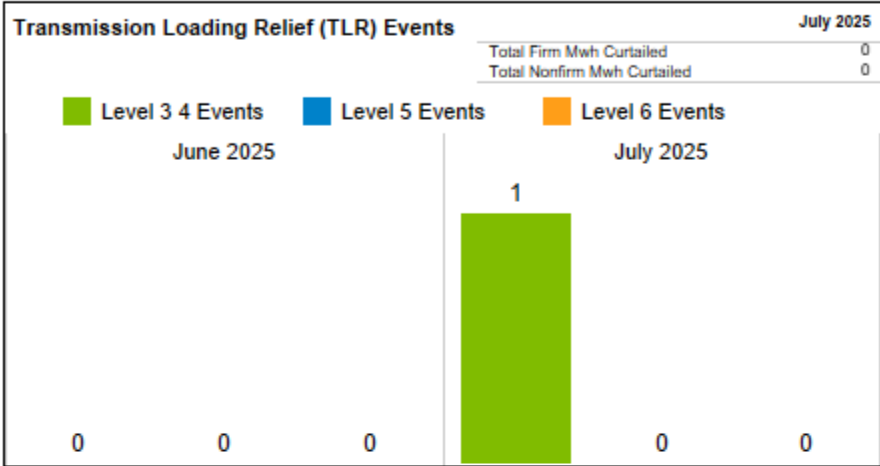
N



Per NERC Standard BAL-001-0 and MISO OP-044, the MISO will monitor CPS 1 performance and implement actions to ensure the MISO's rolling 12-month CPS 1 performance exceeds 100%
Source: MISO Real-Time Operations Department



Reliability — Other Metrics

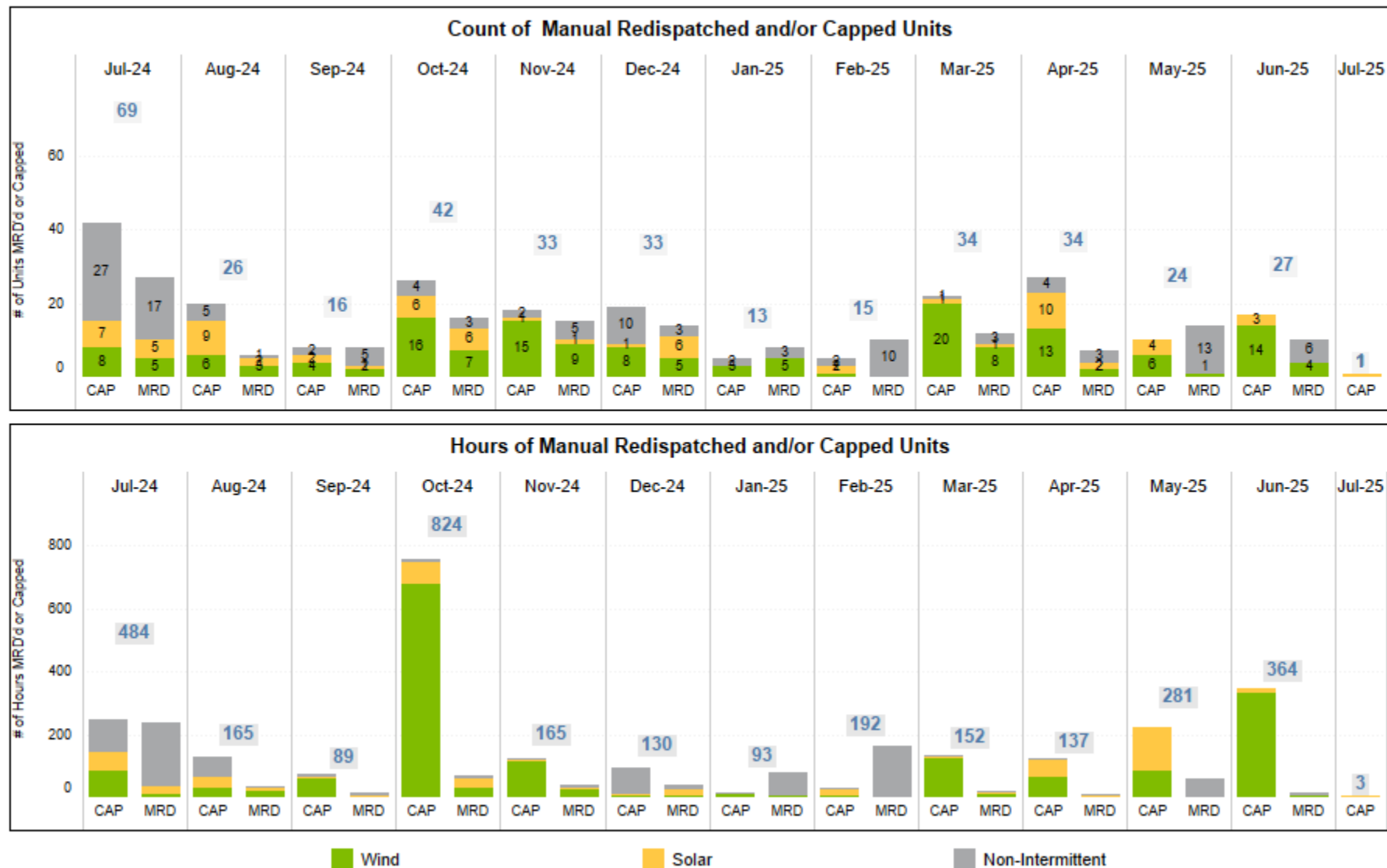


MISO deployed Contingency Reserves **

Date	HE	Deployment Type	MW
6/1/2025	19	OFFLINE	79
		ONLINE	1,227
6/17/2025	5	OFFLINE	338
		ONLINE	961

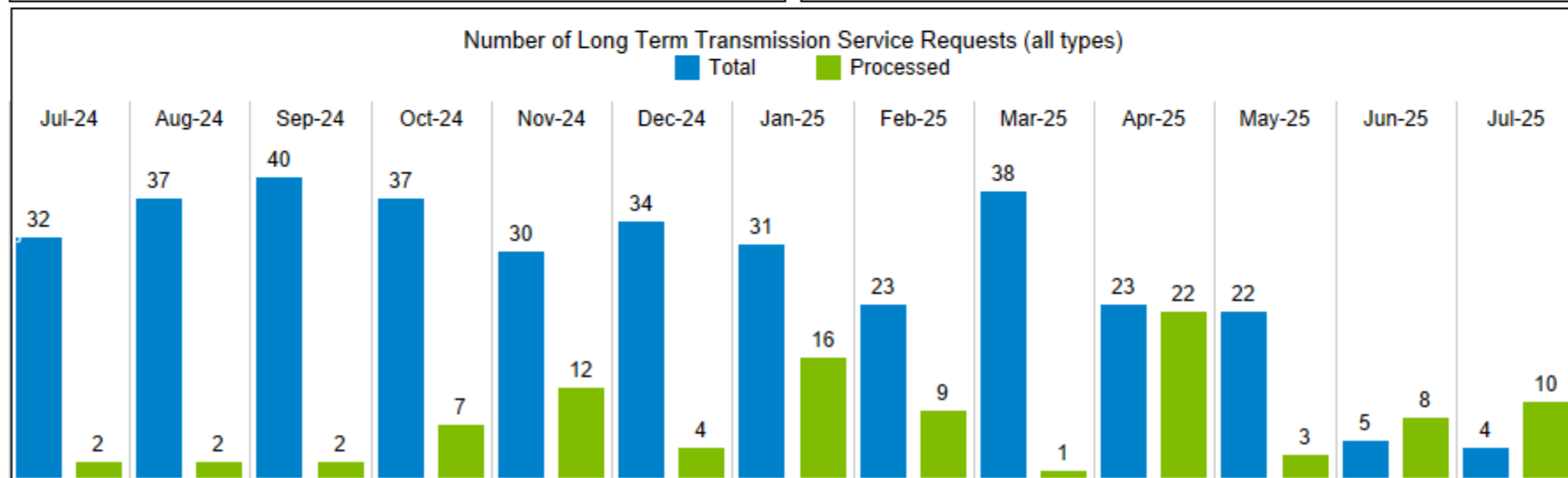
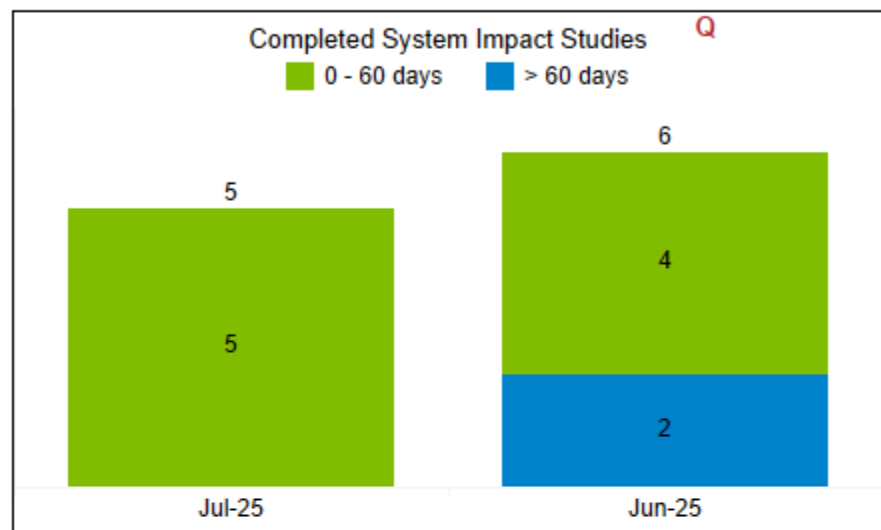
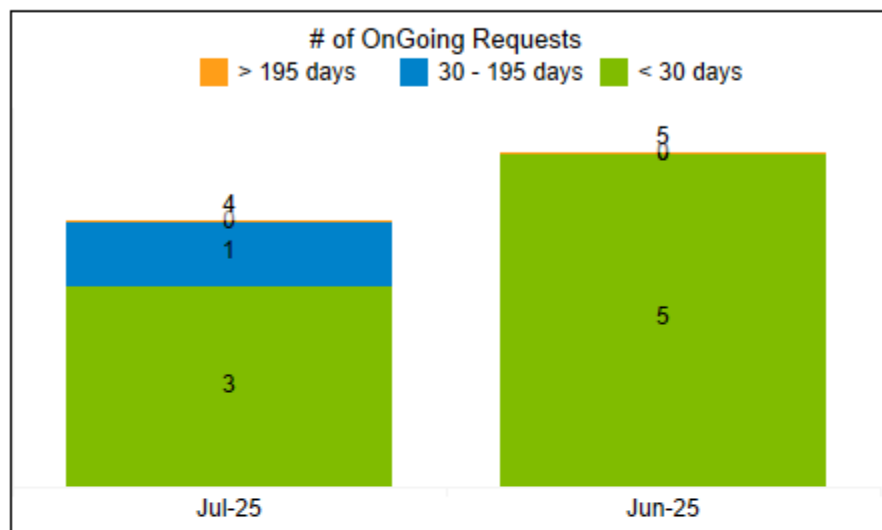
**Historical Contingency Deployment data located in *Related Documents* at <https://cdn.misoenergy.org/202001-202103%20Additional%20Information%20Historical%20Contingency%20Deployment%20Data548321.pdf>

Operator Actions - Manual Redispatch and Caps



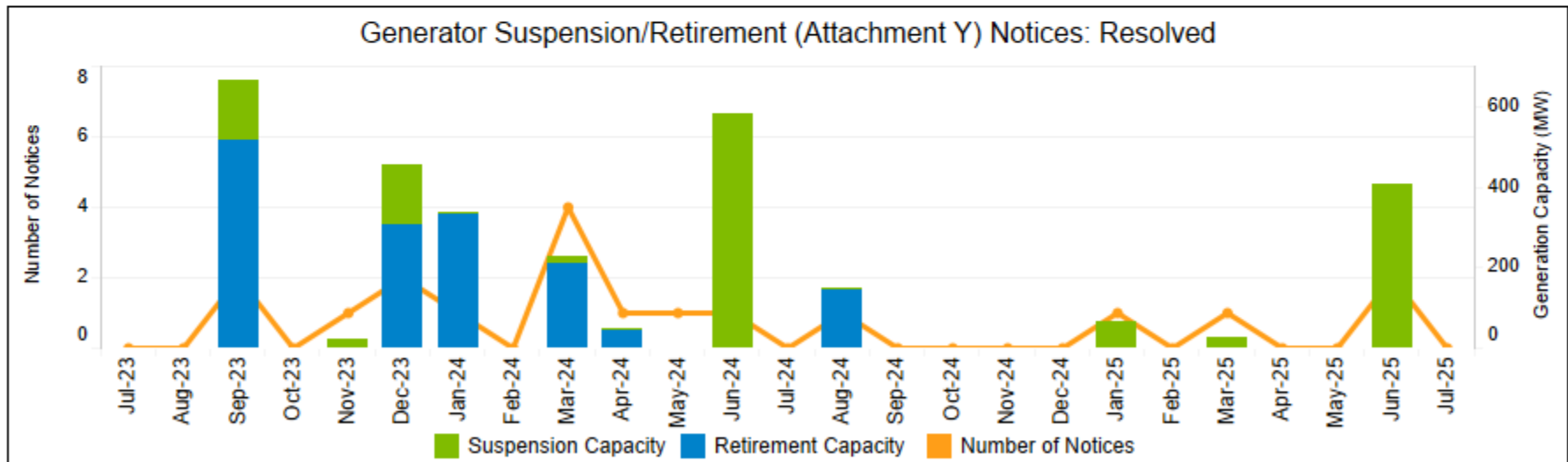
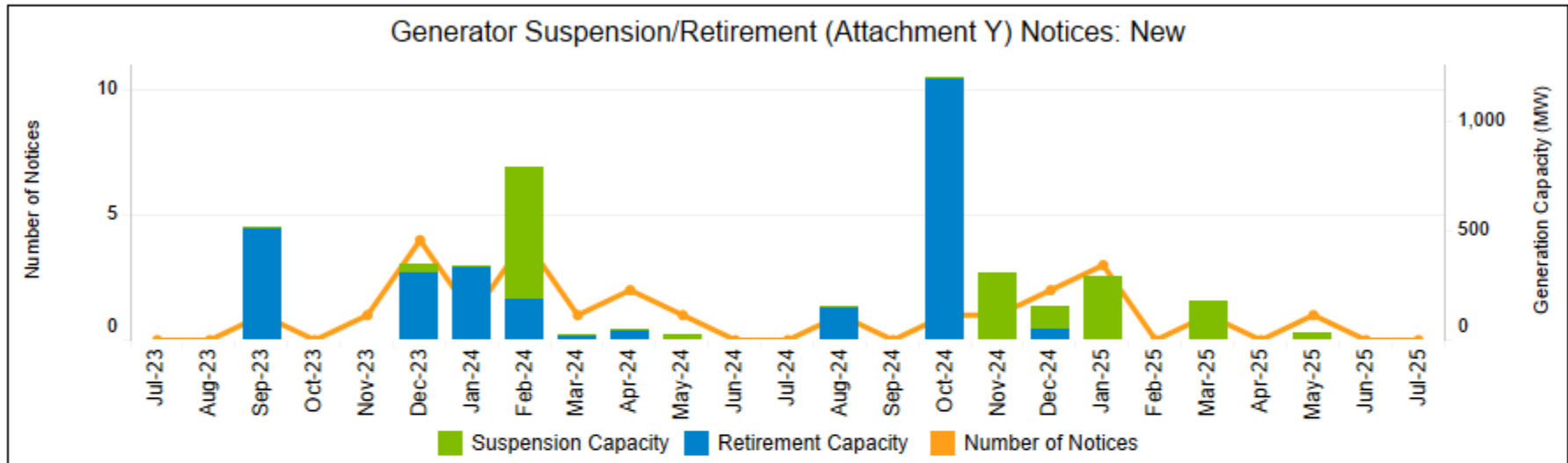
Source: MISO Market and Operations Analytics Department

Transmission Service Request



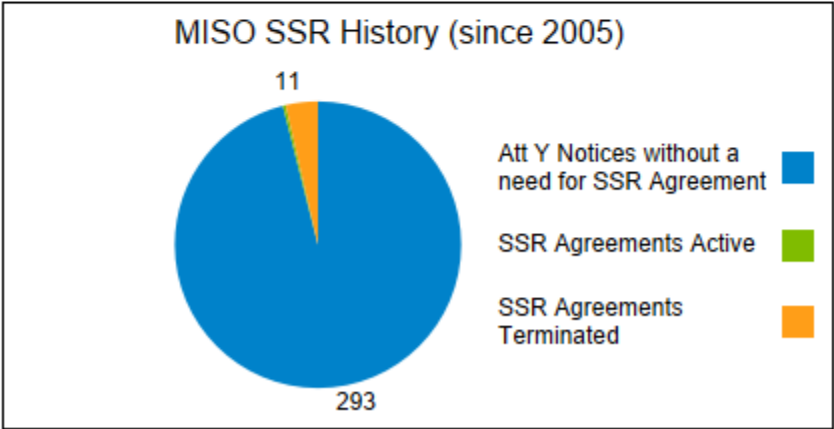
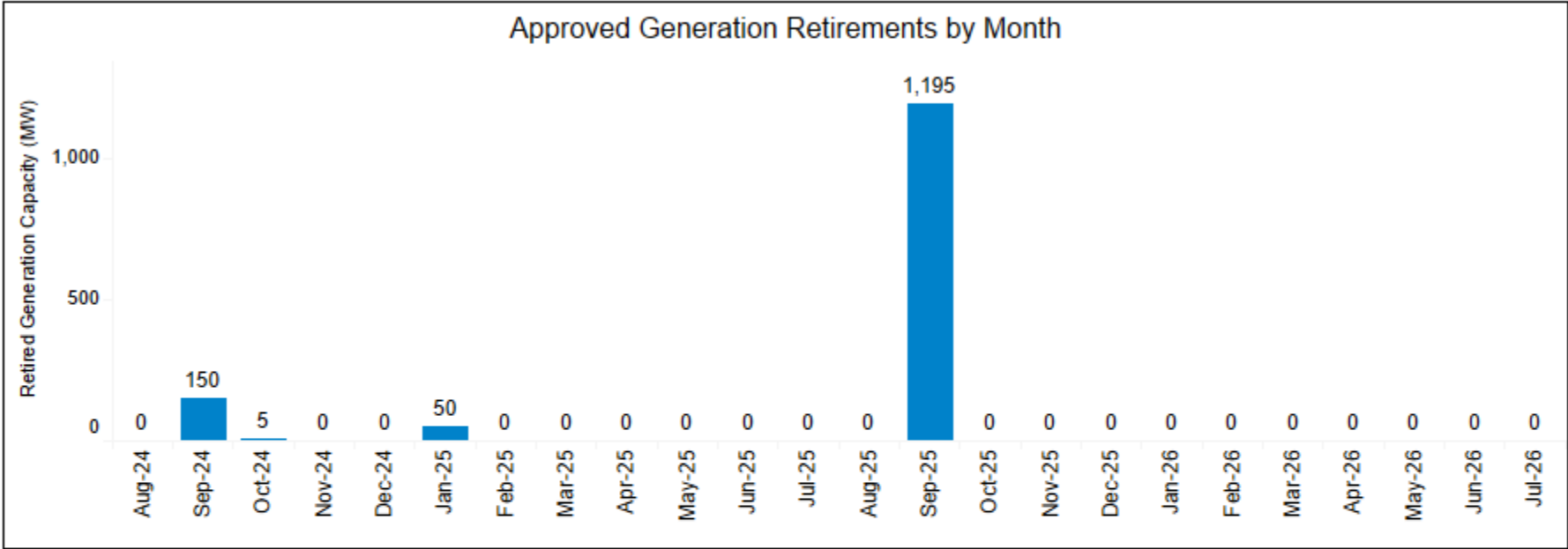
Source: MISO Resource Utilization

Generator Suspension/Retirement - New and Resolved



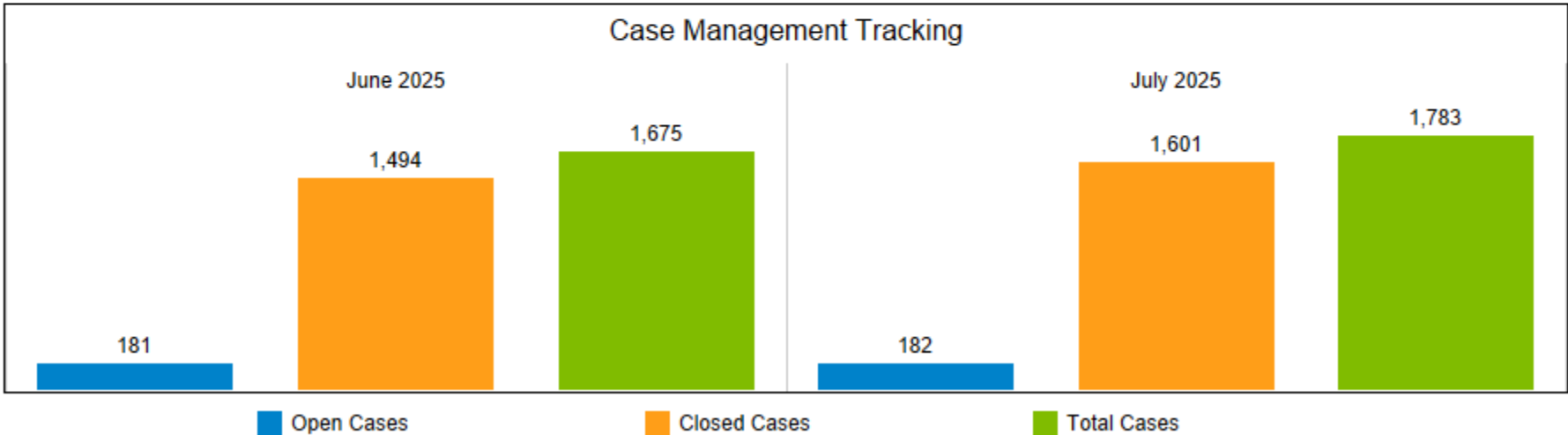
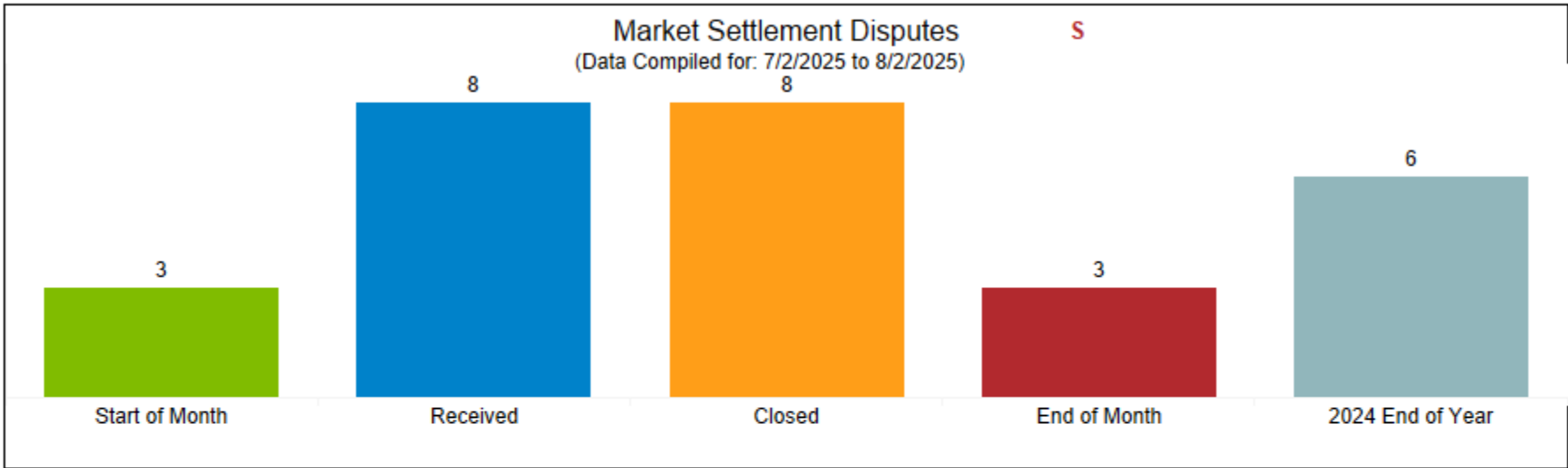
Source: MISO Transmission Planning Department

Generator Suspension/Retirement - Overall



Source - MISO Transmission Planning Department

Settlements/Client Services and Readiness



Source: MISO Settlements and Client Services and Readiness Departments
Settlement values may change due to resettlement
Resource Adequacy, Tariff Pricing, Market Settlements, and Credit cases are included in Case Management Tracking data



MISO has set an even higher standard for its System Availability metrics in 2025, and while January and February had no downtime, a critical incident occurred in March that impacted STI

January - April 2025

Short-Term Incentive Metrics	JAN 25	FEB 25	MAR 25	APR 25	Trend *	YTD	Threshold Target Excellent
Critical Systems Availability (Downtime in Hours)	0.0	0.0	1.5	0.0		1.5	4 Hours 3 Hours 2 Hours
Number of Critical System Incidents Exceeding 30 Minutes	0	0	1	0.0		1	2 1 0
Other Availability Metrics	JAN 25	FEB 25	MAR 25	APR 25	Trend *	Monthly Target	
ICCP** (Availability %)	100	100	100	100		99.5	
Customer Facing Applications – Portals (Availability Index)	10	10	10	10		10 of 10	
Markets (Availability Index)	4	4	4	4		4 of 4	
Reliability Targets (Availability Index)	3	3	3	3		3 of 3	

*Trend lines represent quarter-over-quarter performance

**ICCP = Inter-Control Center Communications Protocol

2025 Dashboard Metric Criteria (1 of 2)

*New or revised 2025
Metric

Operational Excellence									
Metric	Chart	Expected	Monitor	Review	Metric	Chart	Expected	Monitor	Review
Percentage Price Deviation*	A	Absolute DA-RT price difference divided by DA LMP $\leq 28.6\%$	Absolute DA-RT price difference divided by DA LMP is $> 28.6\%$ but $\leq 34.3\%$	Absolute DA-RT price difference divided by DA LMP $> 34.3\%$	Unit Commitment Efficiency*	H	$\geq 93\%$		$< 93\%$
Monthly Average Gross Virtual Profitability*	B	Within the standard deviation bands (threshold \$0.44/MWh)	Outside the standard deviation bands		Real-Time Obligation fulfilled by Day-Ahead Supply at the Peak Hour	I	$\geq 95\%$	$\geq 93\%$ but $< 95\%$	$< 93\%$
FTR Funding	C	Monthly FTR Allocation % is $\geq 92\%$ and YTD FTR Allocation % is $\geq 96\%$	Not in good status AND Monthly FTR Allocation % is $\geq 87\%$ AND Rolling 12-month FTR Allocation % is $\geq 93\%$	Not in Good AND not in Monitor status	Day Ahead Wind Generation Forecast Error	K	# of days that the hourly average forecast error exceeds $10\% \leq 6$	# of days that the forecast error exceeds $10\% > 6$ or Forecast error exceeds 15% in = 3 days	# of days that the forecast error exceeds $10\% > 8$ or Forecast error exceeds 15% in > 3 days or Forecast error resulted in declaring 1 Real Time Event
Market Efficiency Metric	D	$\geq 95\%$		$< 95\%$	Day Ahead Solar Generation Forecast Error	T	# of days that the hourly average forecast error exceeds $10\% \leq 6$	# of days that the forecast error exceeds $10\% > 6$ or Forecast error exceeds 15% in = 3 days	# of days that the forecast error exceeds $10\% > 8$ or Forecast error exceeds 15% in > 3 days or Forecast error resulted in declaring 1 Real Time Event
RSG per MWh to Energy Price*	E	$\leq 0.38\%$	$> 0.38\%$ and $\leq 0.46\%$	$> 0.46\%$	Tie Line Error	L	≤ 1	> 1 but ≤ 3	> 3
Day Ahead Mid-Term Load Forecast**	F	# of days that forecast error exceeds $3\% \leq 6$ AND # days that forecast error exceeds $4\% \leq 4$	# of days that forecast error exceeds $3\% > 6$ OR # days that forecast error exceeds $4\% > 4$ OR forecast error exceeds 6% on ≥ 1 day	# of days that forecast error exceeds $3\% > 10$ OR # days that forecast error exceeds $4\% > 8$ OR forecast error exceeds 7% on ≥ 1 day OR Forecast error resulted in declaring 1 Real Time Event	Control Performance – BAAL	M	Monthly performance score ≥ 2	Monthly performance score < 2 but ≥ 1	Monthly performance score < 1

FTR YTD metric is applied beginning April

** Forecast errors observed in March, April, October and November will be measured by 1% lower thresholds

2025 Dashboard Metric Criteria (2 of 2)

*New or revised 2025
Metric

Operational Excellence									
Metric	Chart	Expected	Monitor	Review	Metric	Chart	Expected	Monitor	Review
Short-Term Load Forecast*	G	Forecast error exceeding the 95% percentile of forecast error for the past year <= 2 days	3 days <= Forecast error exceeding the 95% percentile of forecast error for the past year <= 5 days	Forecast error exceeding the 95% percentile of forecast error for the past year > 5 days	Control Performance - CPS1 and CPS1 12-month rolling	N	>=100%		<100%
					ARS Deployment	P	DCS monthly average % recovery (APR) = 100%	Analysis of event not yet complete	DCS monthly average % recovery (APR) confirmed <100%
Customer Service									
System Impact Study Performance	Q	Studies completed in less than 60 days >=85%	Studies completed in less than 60 days <85% but >=75%	Studies completed in less than 60 days <75%	Settlement Disputes	S	Increase of up to 20 disputes	Increase of between 20 and 50 disputes	Increase of more than 50 disputes

FTR YTD metric is applied beginning April

** Forecast errors observed in March, April, October and November will be measured by 1% lower thresholds
Two days in December 2022 have been removed from threshold calculations..





MISO'S RESPONSE TO THE RELIABILITY IMPERATIVE

- UPDATED FEBRUARY 2024 -

Living Document

This is a “living” report that is updated periodically as conditions evolve, and as MISO, stakeholders and states continue to assess and respond to the Reliability Imperative.



misoenergy.org



Contents

A Message from John Bear, CEO	1
Executive Summary	2
Challenges Driving the Reliability Imperative	6
Pillar 1: Market Redefinition	13
Pillar 2: Operations of the Future	16
Pillar 3: Transmission Evolution	18
Pillar 4: System Enhancements	23

Appendix:

MISO Roadmap	A-1
MISO's Role	A-2
The MISO Value Proposition	A-3
Informing the Reliability Imperative	A-4
Acronyms Used in This Report	A-5



A Message from John Bear, CEO



We have to face some hard realities.

There are immediate and serious challenges to the reliability of our region's electric grid, and the entire industry — utilities, states and MISO — must work together and move faster to address them.

MISO and its utility and state partners have been deeply engaged on these challenges for years, and we have made important progress. But the region's generating fleet is changing even faster and more profoundly than we anticipated, so we all must act with more urgency and resolve.

Many utilities and states are decarbonizing their resource fleets. Carbon emissions in MISO have declined more than 30% since 2005 due to utilities and states retiring conventional power plants and building renewables such as wind and solar. Far greater emissions reductions — possibly exceeding 90% — could be achieved in coming years under the ambitious plans and goals that utilities and states are pursuing.

Studies conducted by MISO and other entities indicate it is possible to reliably operate an electric system that has far fewer conventional power plants and far more zero-carbon resources than we have today. However, **the transition that is underway to get to a decarbonized end state is posing material, adverse challenges to electric reliability.**

A key risk is that many existing “dispatchable” resources that can be turned on and off and adjusted as needed are being replaced with weather-dependent resources such as wind and solar that have materially different characteristics and capabilities. While wind and solar produce needed clean energy, they lack certain **key reliability attributes** that are needed to keep the grid reliable every hour of the year. Although several emerging technologies may someday change that calculus, they are not yet proven at grid scale. Meanwhile, efforts to build new dispatchable resources face headwinds from **government regulations and policies**, as well as **prevailing investment criteria for financing new energy projects**. Until new technologies become viable, we will continue to need dispatchable resources for reliability purposes.

But fleet change is not the only challenge we face. **Extreme weather events** have become more frequent and severe. **Supply chain and permitting issues** beyond MISO's control are delaying many new reliability-critical generation projects that are otherwise fully approved. **Large single-site load additions**, such as energy-intensive production facilities or data centers, may not be reliably served with existing or planned resources. **Incremental load growth** due to electric vehicles and other aspects of electrification is exerting new pressure on the grid. And **neighboring grid systems are becoming more interdependent** and reliant on each other, highlighting the need for more interregional planning such as the Joint Targeted Interconnection Queue study that MISO conducted with Southwest Power Pool.

This report documents how MISO is addressing these risks through the **Reliability Imperative** — the critical and shared responsibility that MISO, our members and states have to address the urgent and complex challenges to electric reliability in our region. MISO first published a Reliability Imperative report in 2020, and this is the fourth time we've updated it to reflect the changing landscape.

None of the work we must do is easy, but it is necessary. The region's 45 million people are counting on MISO and its utility and state partners to get it right. Thank you for your interest in these important issues.



Executive Summary

THE CHALLENGE: A “HYPER-COMPLEX RISK ENVIRONMENT”

There are urgent and complex challenges to electric system reliability in the MISO region and elsewhere. This is not just MISO’s view; it is a well-documented conclusion throughout the electric industry. The North American Electric Reliability Corporation, a key reliability entity throughout the U.S., Canada and part of Mexico, has described these challenges as a [“hyper-complex risk environment.”](#) These challenges include:

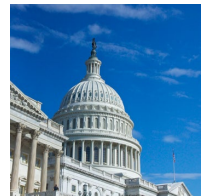
Fleet change: The new weather-dependent resources that are being built, such as wind and solar, do not provide the same critical reliability attributes as the conventional dispatchable coal and natural gas resources that are being retired. While emerging technologies such as long-duration battery storage, small modular reactors and hydrogen systems may someday offer solutions to this issue, they are not yet viable at grid scale.



Regulations, policies and investment criteria: Many dispatchable resources that provide critical reliability attributes are retiring prematurely due to environmental regulations and clean-energy policies. This regulatory environment, along with prevailing investment criteria for financing new energy projects, increases the challenges to build new dispatchable generation — even if it is critically needed for reliability purposes.



Fuel assurance: Gas resources can face challenging economics to procure fuel because they share the pipeline system with residential and commercial heating and manufacturing uses. Coal plants typically keep large stockpiles of fuel onsite, but coal supplies have tightened due to changing economics, import/export dynamics, supply chain issues and other factors. Aging resources can also be more prone to outages. While renewable resources such as wind turbines do not use “fuel” per se, they are sometimes unavailable due to adverse weather conditions.



Extreme weather events: While extreme weather has always been commonplace in the MISO region, severe weather events that impact electric reliability have been increasing. The [Electric Power Research Institute found](#) that hurricanes are increasing in intensity and duration, heat events are increasing in frequency and intensity and cold events are increasing in frequency. Examples include Winter Storm Elliott in 2022, Winter Storm Uri in 2021, Hurricane Ida in 2021, and Hurricanes Laura, Delta and Zeta in 2020.



Load additions: Some parts of the MISO region are enjoying a resurgence in manufacturing and/or other types of economic growth, with companies planning and building new factories, data centers and other energy-intensive facilities. While such development is welcome from an economic perspective, it can also pose significant reliability risks if the load additions it spurs cannot be reliably served with existing or planned resources.



Incremental load growth: While electricity demand has been flat for many years, it is expected to increase due to the electrification of other sectors of the economy. Electric vehicles are growing in popularity, and the residential and commercial sectors are increasingly using electricity for heating and cooling. These trends will accelerate more due to the electrification tax credits in the 2022 Inflation Reduction Act.





Supply chain and permitting issues: Many projects that have been fully approved through MISO's Generator Interconnection Queue process are not going into service on schedule due to supply chain issues and permitting delays that are beyond MISO's control. As of late 2023, about 25 gigawatts (GW) of approved resources are signaling delays that average 650 days to commercial operation.



RELIABILITY IMPERATIVE OVERVIEW

The **Reliability Imperative** is the term MISO uses to describe the shared responsibility that MISO, its members and states have to address the urgent and complex challenges to electric system reliability in the MISO region. MISO's *response* to the Reliability Imperative consists of numerous interconnected and sequenced initiatives that are organized into four primary pillars, as shown here:

RELIABILITY IMPERATIVE PILLAR	KEY INITIATIVES (<i>partial list</i>)
MARKET REDEFINITION Enhance and optimize MISO's markets to ensure continued reliability and efficiency while enabling the changing resource mix, responding to more frequent extreme weather events, and preparing for increasing electrification	• Ensure resources are accurately accredited • Identify critical system reliability attributes • Ensure accurate pricing of energy & reserves
OPERATIONS OF THE FUTURE Focus on the skills, processes and technologies needed to ensure MISO can effectively manage the grid of the future under increased complexity	• Manage uncertainty associated with increasing reliance on variable wind and solar generation • Prepare control room operators to rapidly assess and respond to changing system conditions • Use artificial intelligence & machine learning to enhance situational awareness & communications • Evaluate interdependency of neighboring systems
TRANSMISSION EVOLUTION Assess the region's future transmission needs and associated cost allocation holistically, including transmission to support utility and state plans for existing and future generation resources	• Develop "Futures" planning scenarios using ranges of economic, policy, and regulatory inputs • Develop distinct "tranches" (portfolios) of Long Range Transmission Plan (LRTP) projects • Enhance joint transmission planning with seams partners • Improve processes for new generator interconnections and retirements
SYSTEM ENHANCEMENTS Create flexible, upgradeable and secure systems that integrate advanced technologies to process increasingly complex information and evolve with the industry	• Modernize critical tools such as the Day-Ahead and Real-Time Market Clearing Engines • Fortify cybersecurity and proactively address the rapidly evolving cyber threat landscape • Develop cutting-edge data and analytics strategies



RECENT KEY ACCOMPLISHMENTS

MISO and its stakeholders have made great progress under the Reliability Imperative in recent years. Some of our key accomplishments to date include:

Seasonal Resource Adequacy Construct: In August 2022, the Federal Energy Regulatory Commission (FERC) approved MISO's proposal to shift from its summer-focused resource adequacy construct to a new four-season construct that better reflects the risks the region now faces in winter and shoulder seasons due to fleet change, more frequent and severe extreme weather, electrification and other factors. This new construct seeks to ensure that resources will be available when they are needed most by aligning resource accreditation with availability during the highest risk periods in each season.

LRTP Tranche 1: The first of four planned portfolios of Long Range Transmission Planning (LRTP) projects was [approved by the MISO Board of Directors](#) in July 2022. This tranche of 18 projects represents a total investment of \$10.3 billion — the largest portfolio of transmission projects ever approved by a U.S. Regional Transmission Organization. These projects will integrate new generation resources built in MISO's North and Central subregions, supporting the reliable and affordable transition of the fleet and further hardening the grid against extreme weather events.

Reliability-Based Demand Curve: MISO's Planning Resource Auction (PRA) was not originally designed to set higher capacity clearing prices as the magnitude of a shortfall increases. This lack of a "warning signal" can mask an imminent shortfall — as occurred with the 2022 PRA. Accurate capacity pricing is also crucial to make effective investment and retirement decisions. MISO worked with its stakeholders to design a Reliability-Based Demand Curve that will improve price signals in the PRA. Full implementation is planned for the 2025 PRA, subject to FERC proceedings.

Futures Refresh: The MISO Futures utilize a range of economic, policy and technological inputs to develop three scenarios that "bookend" what the region's resource mix might look like in 20 years. In 2023, MISO updated its Futures to lay the groundwork for LRTP Tranche 2 and to better reflect evolving decarbonization plans of MISO members and states. The refreshed Futures also model how the financial incentives for clean energy in the 2022 Inflation Reduction Act could further accelerate fleet change. The refreshed Futures are indicated with an "A" (e.g., Future 2 was updated and renamed Future 2A).

System Enhancements: The Market System Enhancement (MSE) program made significant progress in 2023. In March, the Energy Management System upgrade was moved into service. This provides a more stable platform with improved visualization while enhancing functionality and user experience. MISO also took delivery of the Reliability Assessment Commitment for the Real-Time Market Clearing Engine, which will improve application security and reduce solution time. MISO also completed Model Manager Phase 2, which connects internal applications to improve model data propagation. MSE will continue to deliver more new products, including Day-Ahead and Real-Time Market Clearing Engine items.

MISO PRIORITIES GOING FORWARD

While far from a complete list, some of MISO's key priorities for 2024 include:

Attributes: In 2023, following an in-depth look at the challenges of reliably operating an electric system in a rapidly transforming landscape, MISO published an [Attributes Roadmap](#) of recommended solutions to address the potential scarcity of three priority attributes that appear to pose the most acute risks: system adequacy,



flexibility and system stability. The recommendations include further modernizing the resource adequacy construct, focusing market signals on emerging flexibility needs, and requirements for new capabilities from inverter-based resources. Next, MISO will prioritize attribute solution integration, including handoffs to MISO business units and stakeholder groups and the scoping of ongoing analysis.

Accreditation: MISO must ensure resource accreditation values reflect what we can expect to receive during high-risk periods. For non-thermal resources, MISO's recommended approach blends a probabilistic methodology with availability during tight conditions, leveraging principles from the thermal accreditation reform implemented in 2022. MISO has proposed a three-year transition to the new methodology that will be applied to all non-emergency resources following the transition period. A FERC filing is planned for 2024.

LRTP Tranche 2: Work to develop the Tranche 2 portfolio of LRTP projects is progressing, with approval by MISO's Board of Directors anticipated in 2024. Planning is complex, but MISO will continue to balance the need to plan quickly with the need to develop a robust, lowest-cost portfolio. Tranche 2 is based on the refreshed Future 2A, which reflects all decarbonization plans of MISO members and states. As with Tranche 1, MISO anticipates Tranche 2 will deliver sufficient benefits to qualify under the Multi-Value Project cost allocation mechanism, with costs allocated only to the subregion where benefits are realized.

CALL TO ACTION: WE MUST WORK TOGETHER AND MOVE FASTER

In light of the urgent and complex risks to electric reliability in the MISO region, utilities, states and MISO must all act with more urgency and more coordination to avoid a looming mismatch between the pace of adding new resources and the retirement of older resources in the MISO region. This means we must:

- Refine generation resource plans across MISO by accelerating the addition of reliability attributes and moderating retirements to avoid undue reliability risk
- Maintain transition resources as reliability “insurance” until promising new technologies become viable at grid scale
- Identify areas of risk in which electricity providers, states and MISO must coordinate

CONTINUED STAKEHOLDER INPUT IS CRUCIAL

Many of the ideas and proposals in this report reflect a great deal of technical input from MISO stakeholders. MISO appreciates stakeholder feedback on the Reliability Imperative, and we look forward to continuing the dialogue. This document is a “living” report that MISO regularly updates.



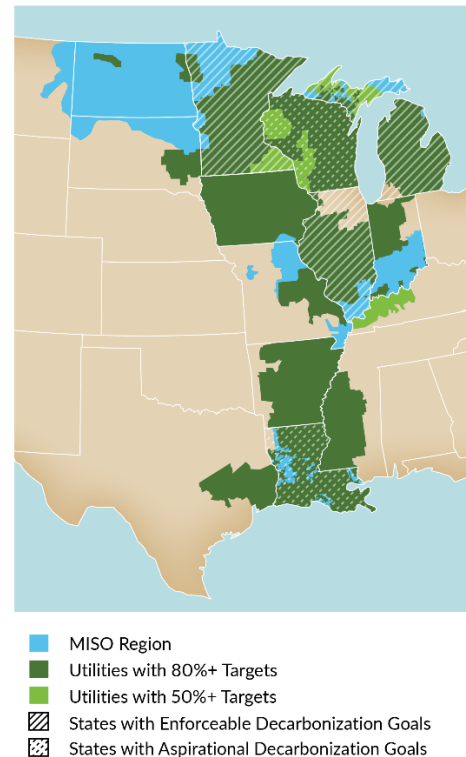
Challenges Driving the Reliability Imperative

COMPLEX POLICY LANDSCAPE

As the map indicates, many utilities and states in the MISO region have adopted policies and goals to decarbonize their resource fleets. Currently, about 75% of the region's total load is served by utilities that have ambitious decarbonization and/or renewable energy goals.

Without question, utilities and states are making remarkable progress toward their goals. Carbon emissions in MISO have already declined more than 30% since 2005, and far greater reductions are expected going forward.

Currently, wind and solar generation account for about 20% of the region's total energy. Under MISO modeling scenario Future 2A, which reflects all the clean-energy goals that utilities and states have publicly announced, wind and solar are projected to serve 80% of the region's annual load by 2042. Fleet change of that magnitude would foster a 96% reduction in carbon emissions compared to 2005 levels – which would be an extraordinary accomplishment for a region that was predominately reliant on fossil fuels not that long ago.



But at the same time, complex challenges to electric system reliability have been steadily materializing throughout the U.S. in recent years, including in MISO. These challenges are driven by a combination of economic, technological and policy-related factors along with extreme weather events. Here is a look at some of these challenges and the drivers associated with them:

TIGHTENING SUPPLY

Over the last 10-plus years, surplus reserve margins in MISO have been exhausted through load growth and unit retirements. Since 2022, MISO has been operating near the level of minimum reserve margin requirements. While MISO has implemented several reforms to help avert near-term risk, more work is urgently needed to mitigate reliability concerns in the coming years. In fact, the region only averted a capacity shortfall in 2023 because some planned generation retirements were postponed and some additional capacity was made available to MISO.

However, MISO cannot count on such actions being repeated going forward. Indeed, the North American Electric Reliability Corporation (NERC) [projects](#) the MISO region will experience a 4.7 GW shortfall beginning in 2028 if currently expected generator retirements actually occur. Notably, NERC says that shortfall will occur *even if* the 12-plus GW of new resources that are expected to come online by then actually materialize. This is because the new resources that are being built have significantly lower accreditation values than the older resources that are retiring, as is discussed in more detail below.



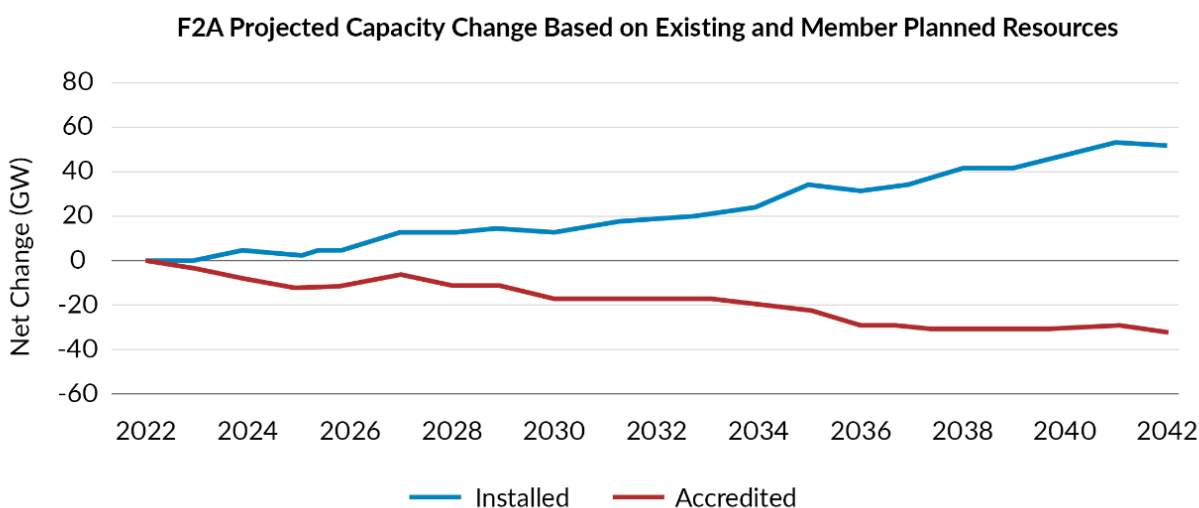
An annual planning tool called the **OMS-MISO Survey** tells a similar story. The survey compiles information about new resources utilities and states plan to build and older assets they intend to retire in the coming years. [The 2023 survey](#) shows the region's level of "committed" resources declining going forward, with a potential shortfall of 2.1 GW occurring as soon as 2025 and growing larger over time. MISO administers the survey in partnership with the [Organization of MISO States \(OMS\)](#), which represents the region's state regulatory agencies.

Other drivers of the region's tightening supply picture include:

- U.S. Environmental Protection Agency (EPA) regulations that prompt existing coal and gas resources to retire sooner than they otherwise would.
- Wall Street investment criteria that make it more challenging to build new dispatchable generation, even if it is critically needed for reliability purposes.
- The approximately \$370 billion in financial incentives for clean-energy resources in the federal Inflation Reduction Act.

DECLINING ACCREDITED CAPACITY

Fleet change is creating a gap between the region's levels of installed and accredited generation capacity. **Installed capacity** is the maximum amount of energy that resources could theoretically produce if they ran at their highest output levels all the time and never shut down for planned or unplanned reasons. **Accredited capacity**, by contrast, reflects how much energy resources are realistically expected to produce during times when they are needed the most by accounting for their performance, which includes limiting factors such as their forced outage rates during adverse weather conditions.



The chart above is from [MISO Future 2A](#), which reflects the publicly announced decarbonization plans of MISO-member utilities and states. As the chart shows, the region's level of *installed* capacity — the blue line — is forecast to increase by nearly 60 GW from 2022 to 2042 due to the many new resources —



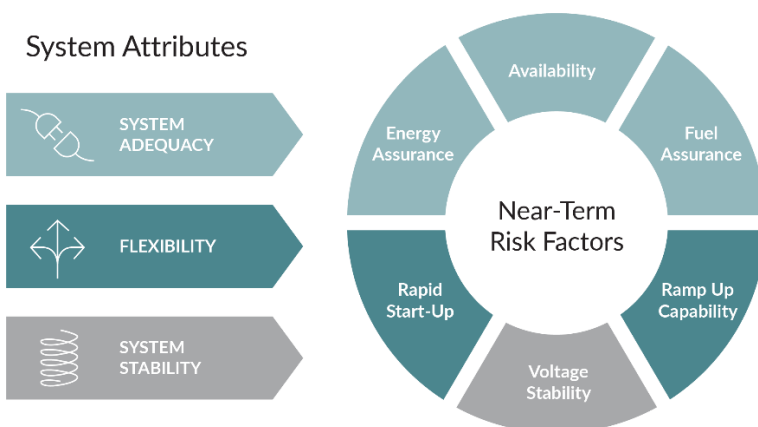
primarily wind and solar — that utilities and states plan to build in that 20-year time period.¹ But because those new wind and solar resources have significantly lower accreditation values² than the conventional resources that utilities and states plan to retire in the same 20-year period, the region's level of *accredited* capacity — the red line — is forecast to decline by a net 32 GW by 2042.

MISO modeling indicates that a reduction of that magnitude could result in load interruptions of three to four hours in length for 13-26 days per year when energy output from wind and solar resources is reduced or unavailable. Such interruptions would most likely occur after sunset on hot summer days with low wind output and on cold winter days before sunrise and after sunset.

NEED FOR SYSTEM RELIABILITY ATTRIBUTES

Reliably navigating the energy transition requires more than just having sufficient generating capacity; it also requires urgent action to avoid a looming shortage of broader **system reliability attributes**. In 2023, MISO completed a foundational analysis of attributes, with a focus on three priority attributes where risk for the MISO system is most acute:

- **System adequacy** is the ability to meet electric load requirements during periods of high risk. MISO focused on the near-term risk factors of availability, energy assurance and fuel assurance.
- **Flexibility** is the extent to which a power system can adjust electric production or consumption in response to changing system conditions. MISO focused on the near-term risk factors of rapid start-up and ramp-up capability.
- **System stability** is the ability to remain in a state of operating equilibrium under normal operating conditions and to recover from disturbances. MISO focused on the nearest-term risk factor of voltage stability.



No single type of resource provides every needed system attribute; the needs of the system have always been met by a fleet of diverse resources. However, in many instances, the new weather-dependent resources that are being built today do not have the same characteristics as the dispatchable resources they are replacing. While studies show it is possible to reliably operate the system with substantially lower levels of dispatchable resources, the transformational changes require MISO and its members to study, measure, incentivize and implement changes to ensure that new resources provide adequate levels of the needed system attributes.

¹ It is not a typical industry practice for utilities and states to publicly announce their resource plans a full 20 years in advance, which is the time horizon that MISO used for the MISO Futures. Thus, this forecast should be viewed as a “snapshot in time” that will change going forward as utilities and states solidify their resource plans.

² In the Future 2A model, retiring conventional resources are accredited at 95% or more of their nameplate capacity, while wind is accredited at 16.6% and solar declines over time to 20%. Accreditation values will vary depending on the methodologies and assumptions that were used to create them.



In December 2023, MISO published an [Attributes Roadmap report](#) that recommends urgent action to advance a portfolio of market reforms and system requirements and to provide ongoing attributes visibility through regular reporting.

EMERGING TECHNOLOGIES SHOW PROMISE BUT ARE NOT YET VIABLE AT GRID SCALE

A number of emerging technologies are being developed that could potentially mitigate the challenges described above. They include long-duration battery storage, carbon capture, small modular nuclear reactors and “green” hydrogen produced from renewables, among others.

However, while these technologies show promise for the future, they are not yet commercially viable to be deployed at scale. MISO is actively engaged in tracking the progress of these technologies and is preparing to incorporate them into the system if/when the opportunity arises.

MISO does expect the commercial viability timelines of these technologies to be accelerated by the \$370 billion in financial incentives for clean energy in the 2022 Inflation Reduction Act. In recognition of that, MISO modeled those incentives in the refreshed MISO Futures. More information on emerging technologies is available in MISO’s [2022 Regional Resource Assessment](#).

LOAD ADDITIONS ARE SURGING

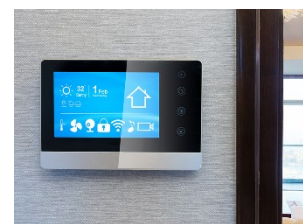
Some parts of the MISO region are enjoying a resurgence in manufacturing and/or other economic growth, with companies planning and building new factories, data centers and other energy-intensive facilities. For example, in the MISO South subregion that spans most of Arkansas, Louisiana, Mississippi and a small part of Texas, there are discussions and plans to build a variety of new manufacturing plants for steel, hydrogen, liquified natural gas and other heavy industry that could add more than 1,000 megawatts (MW) of new load. The tax credits for clean-energy manufacturing in the Inflation Reduction Act are helping to drive some of these additions.



While such development is welcome from an economic perspective, it can also pose significant grid reliability risks if the large load additions it spurs cannot be reliably served with existing or planned resources.

LOAD GROWTH DUE TO INCREMENTAL ELECTRIFICATION

While year-over-year demand for electricity in MISO has been fairly flat for many years, it is expected to increase going forward due to the electrification trends in other sectors of the economy. Electric vehicles are growing in popularity, and the residential and commercial building sectors are increasingly using electricity for heating and cooling purposes — with a desire to source this new electric load from renewables. These trends will likely accelerate even more due to the substantial financial incentives in the Inflation Reduction Act for electric vehicles, rooftop solar systems and electric appliances.





The impacts of these trends could be significant. In MISO's 2021 [Electrification Insights report](#), MISO found that electrification could transform the region's grid from a summer-peaking to a winter-peaking system and that uncontrolled vehicle charging and daily heating and cooling load could result in two daily power peaks in nearly all months of the year.

DELAYS TO APPROVED GENERATION PROJECTS

In addition to reliability being challenged by declining accredited capacity, electrification and load additions, another concern is that a large number of fully approved and much-needed new generation projects are being delayed by supply chain issues, regulatory issues, and other external factors beyond MISO's control.

As of late 2023, about 25 GW of fully approved generation projects in MISO's Generator Interconnection Queue had missed their in-service deadlines by an average of 650 days, with developers citing supply chain and permitting issues as the two biggest reasons for the delays. An additional 25 GW of fully approved queue projects had not yet missed their in-service deadlines as of late 2023, but MISO expects many of them will also be delayed by external factors.

As the region's capacity picture continues to tighten, the possibility that upward of 50 GW of fully approved new generation projects could be delayed by external factors beyond MISO's control is deeply concerning.

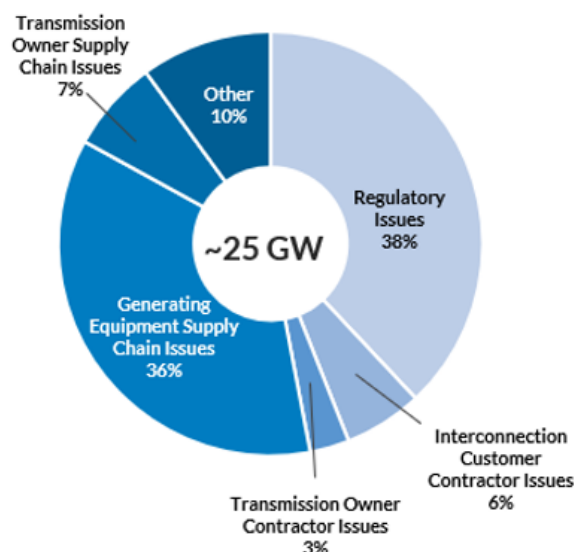
FUEL ASSURANCE RISKS

The transition to a low- to no-carbon electric grid also poses risks in the realm of fuel assurance. These risks impact conventional coal and gas resources that provide reliability attributes such as system adequacy, flexibility and system stability that may be becoming scarce due to fleet change.

Coal resources have historically been considered fuel-assure because large stockpiles of fuel can be stored on-site. However, coal supplies have tightened in recent years due to a confluence of factors, including contraction of the mining and transportation sectors and supply chain issues. These factors increase the risk that coal plants will be unable to perform due to a lack of fuel availability. Coal resources can also be affected by extreme winter weather freezing onsite coal piles and/or impacting coal-handling equipment.

Gas-fired resources are also subject to fuel-assurance risks because they rely on pipelines to deliver gas to them. However, because the pipeline system was largely built for home-heating and manufacturing purposes, gas power plants sometimes face very challenging economic conditions to procure the fuel they need to operate. In the MISO region, this has historically occurred during extreme winter weather events that drive up home-heating needs for gas. Many gas generators in MISO do not have "firm" fuel-delivery

25 GW of fully approved & much-needed generation projects are delayed by supply chain and other issues



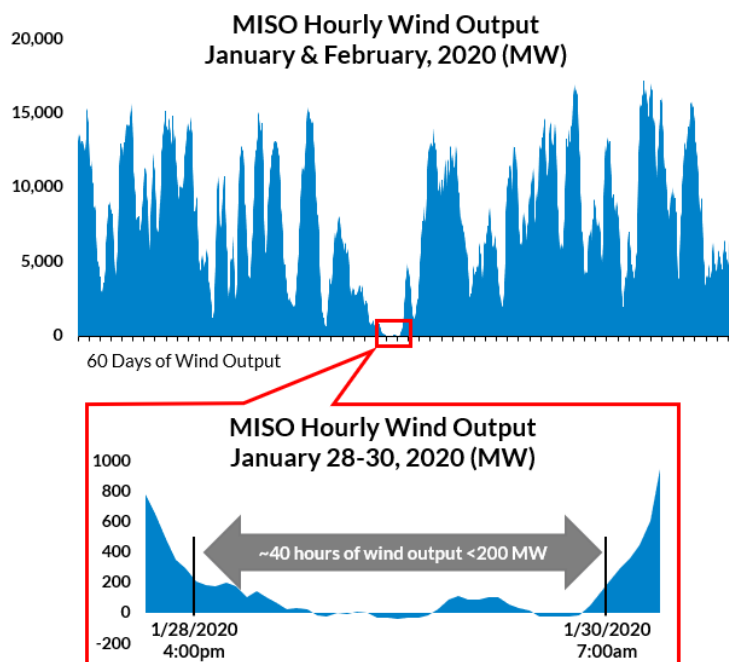


contracts, opting instead for less costly “interruptible” pipeline service or a blend thereof. Only about 27% of the gas generation that responded to MISO’s [2023-2024 Generator Winterization Survey](#) indicated it had firm transport contracts in place for all of their supplies during the 2023-2024 winter season. Additionally, gas power plants, gas pipelines and coal generators can be forced out of service by icing and other effects of severe winter weather — as has occurred in the MISO region and elsewhere with increasing frequency.

WIND DROUGHTS

Wind resources can experience “fuel” availability challenges in the form of highly variable wind speeds. Consequently, the energy output of wind can fluctuate significantly on a day-to-day and even an hour-by-hour basis — including multi-day periods when output drops far below average.

For example, over 60 consecutive days in January-February 2020, hourly wind output in MISO averaged more than 8,000 MW. However, as the chart shows, for 40 consecutive hours in the middle of that 60-day block, average hourly wind output dropped to less than 47 MW, and only once exceeded 200 MW in any single hour.



An even longer and broader “wind drought” occurred during Winter Storm Uri in 2021 when the MISO, Southwest Power Pool, Electric Reliability Council of Texas and PJM regions all experienced 12 consecutive days of low wind output.

Wind turbines can also be unavailable in extremely cold weather. While turbines equipped with special “cold weather packages” are designed to operate in temperatures as low as minus 22 F, they generally cut off if temperatures dip below that point. Still, it is important to keep in mind that all types of generators struggle in extreme cold, not just wind turbines.

EPA REGULATIONS COULD ACCELERATE RETIREMENTS OF DISPATCHABLE RESOURCES

While MISO is fuel- and technology-neutral, MISO does have a responsibility to inform state and federal regulations that could jeopardize electric reliability. In the view of MISO, several other grid operators, and numerous utilities and states, the U.S. Environmental Protection Agency (EPA) has issued a number of regulations that could threaten reliability in the MISO region and beyond.

In May 2023, for example, EPA proposed a rule to regulate carbon emissions from all existing coal plants, certain existing gas plants and all new gas plants. As proposed, the rule would require existing coal and gas resources to either retire by certain dates or else retrofit with costly, emerging technologies such as carbon-capture and storage (CCS) or co-firing with low-carbon hydrogen.



MISO and many other industry entities believe that while CCS and hydrogen co-firing technologies show promise, they are not yet viable at grid scale — and there are no assurances they will become available on EPA’s optimistic timeline. If EPA’s proposed rule drives coal and gas resources to retire before enough replacement capacity is built with the critical attributes the system needs, grid reliability will be compromised. The proposed rule may also have a chilling effect on attracting the capital investment needed to build new dispatchable resources.

RISKS IN NON-SUMMER SEASONS

In the past, resource adequacy planning in MISO focused on procuring sufficient resources to meet demand in the peak hour of the year, which normally occurs on a hot and humid summer day when air conditioning load is very high. If utilities had enough resources to reliably meet that one peak hour in the summer, the assumption was they could operate reliably for the other 8,759 hours of the year.

That assumption no longer holds true. Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region’s historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.

This changing risk profile is why MISO shifted from its annual summer-focused resource adequacy construct to a new framework that establishes resource adequacy requirements on a seasonal basis for four distinct seasons: summer (June-August); fall (September-November); winter (December-February); and spring (March-May). This new seasonal construct also seeks to ensure that resources will be available when they are needed most by aligning resource accreditation with availability during the highest risk periods in each season.





Pillar 1: Market Redefinition

MISO established the energy and ancillary service markets nearly two decades ago when the composition of, and the risks to, the energy industry were very different from today. MISO's [Markets of the Future report](#) indicates that the region's foundational market constructs will continue to be effective going forward, but only with significant revisions. Further informed by the attributes analysis completed in 2023, MISO is enhancing and optimizing its market constructs and products to ensure they continue to deliver reliability and value in the face of fleet change, extreme weather events, electrification and load additions. This work occurs under four themes within the Market Redefinition pillar of the Reliability Imperative, as discussed below.

UNCERTAINTY AND VARIABILITY

In the planning horizon, MISO is addressing the changing risk profile and enhancing market signals for new resource investments. MISO's original resource adequacy construct was designed for a conventional fleet of resources where reliability risk was concentrated during the typical summer peak period. This is no longer the case. Factors such as aging conventional resources, more frequent and severe weather events and increased reliance on weather-dependent renewables have altered the region's historic risk profile, creating new risks in non-summer months and at differing times of the day. As the generation mix further diversifies, the accreditation process of evaluating each generator's contribution to the system is a critical reliability and planning mechanism.

In 2022, FERC approved MISO's proposal to shift from the annual, summer-based resource adequacy construct to a new construct with four seasons. The new seasonal construct also aligns the accreditation of thermal resources with availability in the highest-risk periods. These changes, implemented in the 2023-2024 Planning Resource Auction (PRA), are already delivering positive market outcomes, such as more proactive outage coordination among stakeholders and incentivizing improved unit performance.

MISO completed an evaluation of potential paths for non-thermal accreditation reforms 2022. This resulted in a proposed accreditation reform that leverages the principles from the thermal accreditation reform implemented in 2022, aligning the accreditation methodology for all resource types (except for emergency-only resources). MISO has proposed a transition period to begin applying the new accreditation methodology in the 2028-2029 planning year. The design work is expected to be finished with a filing with FERC in 2024.

The PRA was not designed to set higher capacity clearing prices as the magnitude of a shortfall increases. This lack of a "warning signal" can instill a false sense of calm among PRA participants, masking an imminent shortfall — as occurred with the 2022 PRA. MISO is working with its stakeholders to enhance pricing within the capacity construct by designing a Reliability-Based Demand Curve (RBDC) to better reflect MISO's market guiding principles, reliability risk and help avoid uneconomic retirements. Full implementation is planned for the 2025-2026 PRA, subject to FERC proceedings.



While the RBDC improves price signals in the planning horizon, MISO is also working on pricing reforms in the operating horizon. These focus on **scarcity pricing** when demand and reserve requirements exceed available supply in real time, often happening during extreme events when MISO enters emergency procedures to manage challenging conditions.

MISO's reforms to scarcity pricing will help incentivize appropriate market behavior, manage congestion throughout events and value reserve shortages appropriately, ultimately providing greater transparency and minimizing manual market intervention. MISO's focus areas for 2024 are updating the value of lost load, demand curves and forced-off assets that become physically disconnected from the grid due to weather-related transmission events. MISO has been presenting ideas at the [Market Subcommittee](#) stakeholder group. These enhancements will begin in 2024, with complete implementation expected by 2025.

Lastly, informed by the analysis of critical reliability attributes and in light of the changing reliability risk profiles in the region, MISO will work with stakeholders in 2024 to reevaluate the traditional risk metrics used in the industry for resource adequacy assessments and improve the underlying risk models.

RESOURCE MODELS AND CAPABILITIES

To avoid a looming shortage of necessary voltage stability attributes, as detailed in the [Attributes Roadmap](#), MISO will advance a multistep technology standard to require capabilities from inverter-based resources to support grid stability at interconnection. In January 2023, MISO embarked on a path to improve inverter-based resource performance requirements using a reliability risk-based approach to evaluate potential gaps in MISO's current tariff. MISO finalized the proposed Tariff language in November to address the highest priority performance requirements and capabilities. This proposal is Phase 1 of the recommended four-phase approach, and this cross-matrix "resource models and capabilities" project will continue in the Interconnection Process Working Group (IPWG).

Another area of focus is MISO's work toward compliance with **FERC Order 2222**, which facilitates the participation of distributed energy resources (DERs) in wholesale electricity markets. DERs are small-scale resources such as rooftop solar panels, electric battery storage systems or electric vehicles and their charging equipment. In isolation, these resources would not have much impact on the grid, but when they are aggregated into a larger block, they can be impactful. MISO is developing a plan to comply with this order through broad collaboration with stakeholders, members, regulators, distributors and DER aggregators.

IDENTIFYING LOCATIONAL NEEDS

Another critical focus associated with increased uncertainty and variability is challenging reserve deliverability due to congestion. Historically, MISO utilized reserve zones to procure and reliably deliver reserves. MISO is working to implement improved locational granularity in its reserve products to ensure deliverability. Updating the reserve zones more frequently should enhance market efficiency and system reliability since there would be better alignment between zonal definitions and system conditions.

In addition to the local deliverability of resources, MISO will explore approaches to better hedge congestion through MISO's Auction Revenue Rights (ARR) mechanism and the Financial Transmission



Rights market. Evaluation has identified gaps and is exploring potential areas of improvement, including updating approaches for allocating ARRs, more granular periods, and ways to incentivize outages that better align with day-ahead energy models.

ENHANCING COORDINATION

As operational uncertainty and complexity increase, MISO continues to improve coordination across stakeholders and external entities, including neighboring grid operators. The collaborative **OMS-MISO Survey** provides a prompt view of resource adequacy over the five-year horizon, characterizing relative levels of resource certainty. MISO's **Regional Resource Assessment** (RRA) provides a collective 20-year view of the evolution of members' resource plans. It aims to provide insights that help members, states and MISO prepare for the energy transition. MISO's [Attributes Roadmap](#) specifically identifies the need for evolved coordination between MISO's resource adequacy assessments and MISO state and member planning process to ensure attribute sufficiency. MISO is committed to continued analysis, transparency and collaboration in the Resource Adequacy stakeholder forum.

One example is how transmission owners and MISO are working together on **ambient-adjusted ratings (AARs)** and **seasonal ratings** on transmission lines in the region, per the requirements of FERC Order 881. While using more accurate line ratings does not diminish the need to build new transmission, having the most accurate line rating information can help ensure that the region's transmission system is fully utilized and delivers its maximum value. MISO has engaged in extensive discussions with its transmission owners and consulted with other interested stakeholders to develop a compliance approach that meets the requirements of FERC Order 881 and is consistent with MISO's Tariff.

"Our market products and the signals they send need to evolve and reflect the new realities and trends that we are experiencing. Input and support from our stakeholders will be key in the effective and timely implementation of these changes."

Todd Ramey, MISO Senior Vice President, Markets and Digital Strategy



Pillar 2: Operations of the Future

MISO's control room operations are also challenged by fleet change, extreme weather and other risk drivers. In addition to implementing lessons learned from past events such as Winter Storm Elliott, forward-looking work is underway to ensure MISO has the capabilities, processes and technology to anticipate and respond to operational opportunities and challenges. This work, termed Operations of the Future, focuses on five buckets of work: (1) operations preparedness, (2) operations planning, (3) uncertainty and variability, (4) situational awareness and critical communications and (5) operational continuity.

OPERATIONS PREPAREDNESS

Tomorrow's control room will be very different from today. Operations preparedness is critical to managing the rapidly changing system conditions, increased volumes of data and enhanced technologies and tools that operators face. To ensure that control room personnel are ready to manage reliability effectively and efficiently in this new and continually evolving environment, MISO is developing improved operations simulation tools and enhancing operator training. In the future, operator and member training and drills will leverage a robust simulator that mirrors production and can quickly incorporate and maintain real-time event scenario simulations with broad, controlled access capabilities.

"In the past, predicting load and generation was relatively straight-forward. In the future, the operating environment will be much more variable, and we need the people, processes and technology to deal with that variability."

Jennifer Curran, MISO Senior Vice President, Planning & Operations
and Chief Compliance Officer

OPERATIONS PLANNING

Operations planning helps MISO to remain a step ahead of the shifting energy landscape. System operators need to quickly access insights into the future and processes that enable the continued reliable and efficient operation of the bulk electric system. In the future, it will be necessary to leverage information in new ways. The ability to quickly model and analyze realistic planning scenarios will enable operators to develop and modify operating day plans from start to execution. Operators will be better prepared to manage increased uncertainty in resource availability with operational planning processes that are centralized and streamlined and outages that are proactively scheduled leveraging predictive economic impact analysis and power system studies.



UNCERTAINTY AND VARIABILITY

The increase in variable generation such as wind and solar has introduced greater uncertainty. Today, operators leverage a variety of market products and other analytics-based tools to manage uncertainty. To help manage increasing complexity, MISO is using machine-learning to predict net uncertainty for the upcoming operating day, using probabilistic forecasts and advanced analytics. With this more complete view, operators can create daily risk assessments that — when coupled with new dynamic reserve requirements — incentivize efficient unit-commitment decisions.

In the future, operators will need to manage the grid reliably and efficiently through tight margins, high-ramping periods, and increased variability by optimizing a risk management framework that accurately provides a risk profile based on net uncertainty impacts and by leveraging predictive economic impact analysis and power system studies.

SITUATIONAL AWARENESS AND CRITICAL COMMUNICATIONS

Situational awareness and critical communications will become even more important as operating risks become less predictable and more difficult to manage in day-to-day operations. New control room technologies and capabilities, improved real-time data capabilities and more complex operating conditions, driven by new load and generation patterns, will require MISO and its members to communicate even more quickly and efficiently.

Today, MISO operations rely heavily on the expertise of its operators. While operators have access to significant amounts of data related to weather, load and more, they must manually synthesize that data into useable information. Although this has worked well historically, solutions must envision a future with more complex information and operators who may not possess the same historical knowledge.

In the future, operators will need an integrated toolset that leverages artificial intelligence and machine learning, combined with additional data and analytics. Improvements in how MISO sees and navigates will give operators important information automatically. Systems will provide situational awareness insights for operators based on their function in the control room. Operators will analyze information and create new displays in real time to quickly assess the impacts of operational situations. Dynamic views of the state of the system will ensure operators can maintain the appropriate level of situational awareness while also reducing operator burden and automating key communication requirements, especially during critical events.

Additionally, enhancements to communications protocols, such as system declarations, will ensure that control rooms have the information they need when they need it. Automated messaging triggered by specific process and procedure actions will reinforce compliance with NERC standards.

OPERATIONAL CONTINUITY

Operational continuity capabilities need to evolve to align with the changing technologies, resource portfolio and threat landscape. Improved tools and updated processes are vital to ensuring that MISO can reliably operate the grid, mitigate risks, and, if necessary, recover quickly in the event of disruptions to toolsets or control centers.



Pillar 3: Transmission Evolution

The ongoing shift in the resource fleet and the substantial projected increase in load pose significant challenges to the design of the transmission system in the MISO region. MISO's Transmission Evolution work addresses these challenges in concert with other elements of the Reliability Imperative framework.

Under Transmission Evolution, MISO holistically assesses the region's future transmission needs while considering the allocation of transmission costs. This work creates an integrated transmission plan that reliably enables member goals while minimizing the total cost of the fleet transition, inclusive of transmission and generation. It also improves the transfer capability of the transmission system — meaning its ability to effectively and efficiently move energy from where it is generated to where it is needed.

LONG RANGE AND INTERREGIONAL TRANSMISSION PLANNING

Regional Long Range Transmission Planning (LRTP) and interregional planning are important parts of the Transmission Evolution pillar. The LRTP effort is developing four tranches of new backbone transmission to support MISO member plans for the changing fleet. In July 2022, the MISO Board of Directors [approved](#) LRTP Tranche 1. The 18-project portfolio of least-regret solutions is focused on MISO's Midwest subregion, representing \$10.3 billion in investment. The projects in Tranche 1 will provide a wide range of value, including congestion and fuel savings, avoided capital costs of local resources, avoided transmission investments, resource adequacy savings, avoided risk of load shedding and decarbonization.

“We see very little risk of over-building the transmission system; the real risk is in a scenario where we have underbuilt the system. Similarly, across markets and operations, our job is to be prepared.”

Clair Moeller, MISO President

This transmission investment hinges on appropriate allocation of the associated costs. MISO's Tariff stipulates a roughly commensurate “beneficiaries pay” requirement that must be met while balancing the divergent needs of MISO's three subregions. Because Tranches 1 and 2 primarily benefit the Midwest subregion, costs will only be allocated there. As Tranches 3 and 4 progress, other approaches may be considered based on stakeholder discussion. Work on Tranche 2 is progressing, with an anticipated approval by MISO's Board of Directors in 2024.

Futures refresh

MISO's future scenarios, or [Futures](#), set the foundation for LRTP. The Futures help MISO hedge uncertainty by “bookending” a range of potential economic, policy and technological possibilities based on factors such as load growth, electrification, carbon policy, generator retirements, renewable energy levels, natural gas prices and generation capital cost over a 20-year period.



Member and state plans often do not provide resource information for the full 20-year study period covered by LRTP. Although MISO does not have authority over generation planning or resource procurement, this lack of information creates a gap in the resources needed to serve load and meet member goals. MISO fills the gap through resource expansion analysis, which seeks to find the optimal resource fleet that minimizes overall system cost while meeting reliability and policy requirements. The resulting resource expansion plans are used with their respective Future to identify transmission issues and solutions.

To lay the groundwork for Tranche 2 and to better understand potential future needs based on the most recent plans, legislation, policies and other factors, MISO [refreshed](#) its three Futures in 2023. While the defining characteristics of each Future remained the same (e.g., load forecast and retirement assumptions), updates were made to data and information that inform the potential resource mix. Among other factors, this includes state and member plans, capital costs, operating and fuel costs and defined resource additions and retirements. MISO also modeled the impacts of the clean energy tax credits in the federal Inflation Reduction Act because those incentives are expected to accelerate the transition to a decarbonized grid.

Future 2A, the focus of Tranche 2, indicates that fleet change will increase in velocity due to stronger renewable energy mandates, carbon reduction goals and other policies. Future 2A projects a 90% reduction in carbon emissions by 2042 and forecasts that wind and solar will provide 30% of the region's energy a full 10 years earlier than the previous Series 1 Futures that were used for Tranche 1.

Planning for an uncertain future

When planning for larger, regional solutions that address needs 20 years into the future, there is inherent uncertainty, which is why LRTP is designed to identify “least-regrets” transmission solutions.

Appropriately managing this uncertainty is a key function of planning. In developing Future 2A, MISO leveraged the consensus on policy goals among MISO members and states about how quickly change would occur. Additionally, MISO's comprehensive processes and robustness testing demonstrate the benefits and needs of transmission solutions that achieve member goals and minimize costs, including several iterations of analyses for Future 2A and other scenarios.

Other visibility tools

As the system becomes more interdependent and interconnected, MISO provides information to members about the outcomes and impacts of their individual plans when studied in the aggregate. Anticipating and communicating changing risks and future systems needs within the planning horizon is critical to ensure continued reliability.

As described earlier in this report, the **OMS-MISO Survey** compiles information about new resources that utilities and states plan to build and older assets they intend to retire in the coming years. While this tool looks several years ahead, certainty is lower in later years when many significant risks will need to be addressed.

Because utility and state plans can be less specific and certain, cover a shorter timeframe and are not always publicly available, MISO conducts the **Regional Resource Assessment (RRA)** to capture more information and details. The RRA aggregates utility and state plans and goals — both public and private —



over a 20-year planning horizon to shed light on regional fleet evolution trends and timing. The information is then used to model potential reliability needs and gaps that may arise and may be leveraged to inform and advance analysis of resource attributes. In the future, new tools will provide stakeholders with ongoing access to RRA information for greater visibility into the impact of these future system changes.

Interregional initiatives

MISO continually works with its neighboring grid operators, Southwest Power Pool (SPP) and PJM, to address issues on the seams. Joint, coordinated, system plan studies are regularly conducted to assess reliability, economic and/or public policy issues. The studies can be more targeted in scope with a shorter study cycle or can be more complex, requiring a longer study period.



The Joint Targeted Interconnection Queue (JTIQ) initiative with SPP is an example of a recent complex study initiative. This unprecedented, coordinated effort identified a portfolio of proposed transmission projects that align with both MISO's and SPP's interconnection processes. These projects will create additional transmission capability to enable generator interconnections in both regions.

In October 2023, the U.S. Department of Energy (DOE) [announced](#) it would award \$464.5 million in federal funding under the Grid Resilience and Innovation Partnerships (GRIP) program to the JTIQ portfolio. This historic opportunity significantly reduces the estimated investment for new transmission lines that will benefit seven states. A FERC filing to obtain approval of cost allocation for the JTIQ portfolio will be submitted in early 2024, and MISO Board approval will be sought thereafter. The process SPP and MISO followed to coordinate the study proved to be effective and significantly more efficient than typical Affected System Studies. Based on its success, the process will be included in the 2024 filing to enable improved coordination in the future.

PLANNING TRANSFORMATION

MISO's planning tools and processes must also evolve as the transitioning resource mix increases the complexity of transmission planning. In response, Planning Transformation, another component of the Transmission Evolution pillar, will develop aligned, adaptable and flexible processes and tools over the next five to 10 years to recognize and address emerging transmission threats and risks identified in markets and operations.

The new [MISO Transmission Expansion Plan \(MTEP\)](#) Portal is a major step in this transformation. The system launched in October 2023 and helps MISO staff and transmission owners manage project data more efficiently and effectively, and it will save hundreds of work hours each year. It also provides stakeholders better support for submitting, updating, tracking and managing MTEP projects and enables more transparency.

Other measures — such as the Generator Interconnection Portal and technology evaluation of resource siting — are already implemented, underway or planned for the future. These include evolving technology



for the resource transition, adapting planning criteria to enhance system resiliency and robustness, and integrating model data.

RESOURCE UTILIZATION

The Resource Utilization initiative focuses on improving resource utilization planning to include a dynamic generator retirement process, more rapid generator interconnections and resource reliability attributes that are addressed throughout the resource lifecycle.

To improve the generator retirement process, asset owners are now required to provide one-year advance notice of resource retirements, an increase from the prior 26 weeks. Quarterly retirement studies have also been instituted to better forecast the engineering workload needed to conduct analyses, and other changes are being implemented that help align retirements with MTEP processes and improve visibility of retirements to stakeholders.

MISO is also working to ensure its processes do not impede generator interconnections. Although MISO's queue processes have been effective in cycles with typical volumes, they are not sufficient for managing recent request volumes that are growing exponentially compared to historical norms. This significantly increases the time it takes MISO to complete studies, which drives more project withdrawals, provides less certainty of early study results, and, ultimately, complicates late-stage studies. These issues are compounded by many speculative projects, despite years of reforms on "first ready, first served" principles.

Improvements to customer-facing and backend operational queue processes over the past several years have enabled more efficient application processing. However, additional changes are needed to manage the dramatic growth in applications, further expedite the interconnection process and maximize transparency and certainty to customers.

As a result, MISO paused accepting interconnection applications for the 2023 cycle, with plans to resume in March 2024 after receiving FERC approval on multiple process improvements to ensure better interconnection requests are submitted. The 2024 cycle is anticipated to begin in the fall of 2024, as it has in previous years.

Tariff changes approved by FERC in January 2024 increase financial commitments and withdrawal penalties and require interconnection customers to provide greater site control for projects. FERC did deny a MISO proposal to cap the size of queue study cycles to ensure they do not exceed a certain percentage of MISO load. However, FERC provided guidance on how MISO could implement a cap in the future, as well as other improvements that will enable the dispatch of existing resources with new interconnection requests. MISO believes these changes will decrease applications and result in higher-quality, more viable projects entering the queue. A reduction in project withdrawals may ultimately reduce network upgrades between studies and provide greater planning certainty for customers and MISO.

In July 2023, FERC issued Order 2023 to ensure that generator interconnection customers can interconnect to the transmission system in a reliable, efficient, transparent, timely and nondiscriminatory manner. The order is mostly consistent with the queue changes MISO has already implemented and

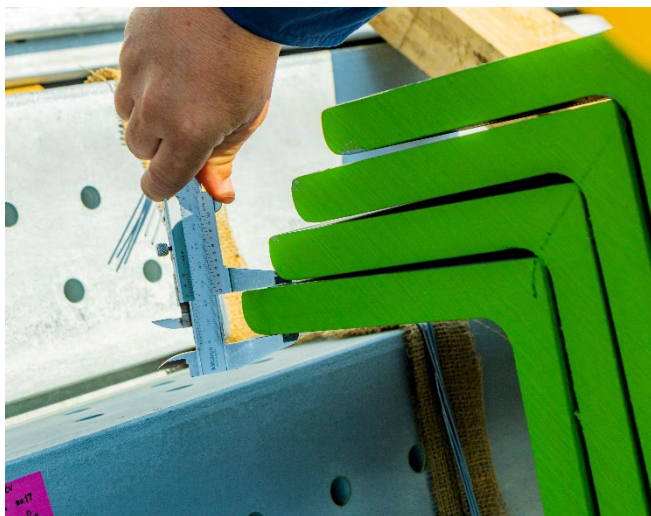


intends to implement going forward. MISO is reviewing the order to assess potential changes and compliance needs.

Lastly, as described in the Resource Models And Capabilities section of this report, MISO is advancing a multistep technology standard to require capabilities from inverter-based resources to support grid stability through the Interconnection Process Working Group. This cross-matrix work is further described in MISO's [Attributes Roadmap report](#) as a solution to mitigate the potential shortage of system stability attributes.

Delays outside of MISO's control

Despite improvements MISO has made to its Generator Interconnection Queue, many fully approved projects are not going into service on schedule due to supply chain issues and permitting delays that are beyond MISO's control. As of late 2023, about 25 gigawatts (GW) of resources that were fully approved through MISO's queue process had missed their in-service deadlines by an average of 650 days, with developers citing supply chain and permitting issues as the two biggest reasons for the delays. An additional 25 GW of fully approved queue projects had not yet missed their in-service deadlines as of late 2023, but MISO expects many of them will also be delayed by external factors.





Pillar 4: System Enhancements

Continual system enhancements and modeling refinements are the bedrock of MISO's response to the Reliability Imperative. The ongoing complexities of the electric industry landscape necessitate paramount upgrades to facilitate reliability-driven market improvements. The Market System Enhancement (MSE) program stands out as a visionary endeavor, focusing on upgrading, building and launching new systems with improved performance, security and architectural modularity. This strategic emphasis enhances MISO's capability to respond swiftly and efficiently and deliver new market products that align with the evolving industry landscape.

MISO places strategic importance on enabling a mature hybrid cloud capability to future-proof the technological infrastructure and foster a resilient and adaptable organizational framework. Simultaneously, the commitment to fostering a flexible work environment amplifies MISO's readiness for ongoing technological changes. This dynamic approach, centered on securely harnessing hybrid cloud technology, optimizes the work environment, positioning MISO for future advancements. The integration of these strategies underlines MISO's forward-looking approach and establishes its leadership in embracing advanced technologies for safeguarding operations.

MARKET SYSTEM ENHANCEMENT (MSE) PROGRAM

The MSE program, initiated in 2017, is a transformative force in reshaping MISO's market platform. Its focus on creating a more flexible, upgradeable and secure system underscores its pivotal role in accommodating the region's evolving portfolio and technology changes. The achievements in 2023 highlight the program's commitment to continuous improvement. The upgrade of the Energy Management System, completion of Phase 2 Core Development, and advancements in the Day-Ahead Market Clearing Engine and Real-Time Market Clearing Engine showcase MSE's impact on improving functionality, user experience, business continuity and security posture. This program is not merely a technological upgrade; it is a strategic initiative that positions MISO to meet the demands of the future electric grid.

“For MISO to continue to deliver on our mission, we must prioritize our plan to address the right strategic drivers that will enable us to accommodate the region’s evolving portfolio and technology changes. The work we do in System Enhancements supports the transformational efforts across the Reliability Imperative and will increase value to our stakeholders.”

Todd Ramey, Senior Vice President, Markets and Digital Strategy



WORK ANYWHERE

MISO's strategic move toward future-proofing its technological infrastructure involves enabling and maturing hybrid cloud capabilities. This initiative goes beyond technology; it embraces the transformative strategy of realizing a flexible work environment that transcends conventional boundaries. The delicate balance between the freedom to work remotely and stringent adherence to security and compliance requirements signifies a definitive change in how MISO approaches work. This shift sets the stage for a more agile and responsive workforce, enhancing productivity and embracing the evolving nature of work. Simultaneously, adopting a well-managed hybrid cloud platform forms the backbone of MISO's technological evolution, allowing seamless operations between on-premises data centers and the public cloud. This combination fortifies organizational resilience and propels MISO into a future where adaptability is the key to sustainable success.

SECURITY OF THE FUTURE

MISO's commitment to seamlessly integrating cutting-edge technologies is underpinned by a dedication to security, reliability and efficiency. This includes initiatives designed to fortify MISO's approach to cybersecurity. Refining identity and access management practices, adopting a proactive zero-trust approach and transforming asset management data quality and timeliness demonstrate MISO's proactive stance against the evolving cyber threat landscape. The commitment extends beyond external threats to assessing security best practices for the internal environment. The ongoing thorough review to evaluate and implement the latest security protocols, conduct regular audits and stay abreast of emerging threats exemplifies MISO's dedication to securing tomorrow.

DATA AND ANALYTICS

MISO's data strategy is a comprehensive framework that goes beyond a simple upgrade — it is a visionary approach to enhancing MISO's data capabilities. The three key priorities — fostering an enterprise culture, delivering a holistic process framework and providing a curated environment — fortify MISO's position as a leader in the energy sector. This strategy modernizes tools, platforms, technologies and processes and empowers teams to model, simulate, analyze and visualize data for informed decision-making. Through a focused and well-defined program, MISO is set to realize a data platform that not only meets the needs of today but is agile enough to adapt to the evolving landscape of data requirements.



MISO Roadmap

As illustrated below, the **MISO Roadmap** outlines MISO's priorities to help its members to reliably achieve their plans and goals. The MISO Roadmap resides on MISO's [public website](#).

--- MISO Roadmap ---

MARKET REDEFINITION INITIATIVES					2024				2025			
					Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Uncertainty & Variability												
Resource Adequacy - Risk Model, Mitigation and Accreditation												
Market Price Alignment During Scarcity												
Resource Models & Capabilities												
Ensure Sufficient Attributes												
Implement Distributed Energy Aggregated Resources (DEAR)												
Demand Response Participation												
Identifying Locational Needs												
Effective Congestion Hedging												
Deliverability of More Flexible, Quick Ramping Market Products												
Enhance Coordination												
Transmission Capability												
Information to Aid Market Decisions												
Bulk Seams Efficiency												
OPERATIONS OF THE FUTURE INITIATIVES					2024				2025			
					Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Operations Preparedness												
Enable Robust Simulation Environment												
Operations Planning												
More Frequent Model Changes												
Align Operational Planning Processes												
Uncertainty & Variability												
Quantify Net Uncertainty												
Situational Awareness & Critical Communication												
Increase Operator Situational Awareness & Visualization												
Maximize Operator Decision-Making Consistency and Efficiency												
Modernize Control Room Critical Communications												
Operational Continuity												
TRANSMISSION EVOLUTION INITIATIVES					2024				2025			
					Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Long Range & Interregional Transmission Planning												
LRTP Tranche 1: Midwest Least Regrets												
LRTP Tranche 2: Midwest Continued Progression												
LRTP Tranche 3: South Region												
LRTP Tranche 4: Midwest/South Interconnection												
Enhance Joint Transmission Planning with Seams Partners												
Explore New Sustainable Cost Allocation Mechanisms to Fit Future Transmission Needs												
Planning Transformation												
Evolve Planning Tools for Resource Transition												
Enhance System Resiliency and Robustness												
Integrate Planning Model Data (Model Manager Phase 3)												
Resource Utilization												
Streamline Resource Interconnection by Implementing Queue Reforms and Order 2023												
Enhance Visibility into Expected Commercial Operation Dates of New Generation Resources												
SYSTEM ENHANCEMENTS INITIATIVES					2024				2025			
					Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Market System Enhancements												
Next Generation Market System												
Work Anywhere												
Flexible Work Environment												
Hybrid Cloud Capability												
Business Continuity												
Security of the Future												
Identify, Protect Against, and Detect Advanced Threats												
Improve Identity and Access Management Practices												
Data & Analytics												
Curated Environment Enabling Intuitive Data Exploration and Utilization												
Process Framework to Advance Analytical Capabilities and Trusted Decision-Making												
Enterprise Culture Where Robust Data Standards are Embedded and Embraced												



MISO's Role

This report is written from MISO's perspective. However, the responsibility for ensuring grid reliability and resource adequacy in the MISO region is not MISO's alone. It is shared among Load Serving Entities (LSEs), states and MISO, each of which have designated roles to play.

LSEs are utilities, electric cooperatives and other types of entities that are responsible for providing power to end-use customers. In most (though not all) of the MISO region, LSEs have designated service territories and are regulated by state agencies. LSEs have exclusive authority to plan and build new generation resources and to make decisions about retiring existing resources, with oversight from state agencies as applicable by jurisdiction.

MISO performs certain transmission planning functions but does not plan or build new generation or decide which existing resources should retire. MISO exercises functional control of its members' generation and transmission assets with the consent of its members and per the provisions of its Tariff, which is subject to approval by FERC. By operating these assets as efficiently as possible on a region-wide basis, MISO generates substantial cost savings and other reliability benefits that would not otherwise be realized.

MISO also establishes and administers resource adequacy requirements for LSEs and states, as applicable by jurisdiction. These include:

- **A Planning Reserve Margin (PRM)** that sets the level of contractually obligated resources that MISO can call into service when normally scheduled resources go offline for planned or unplanned reasons or when demand surges due to extreme weather conditions or other factors. The PRM is set through MISO's stakeholder process.
- **A Planning Resource Auction (PRA)** that LSEs can use to procure needed resources or sell surplus resources. LSEs can "opt out" of the PRA by using their own resources or negotiating bilateral contracts with other entities.
- **Resource accreditation metrics** that determine how much "credit" various types of resources receive toward meeting resource adequacy requirements based on factors such as their unplanned outage rates.
- **Locational procedures** that determine how much capacity is needed in certain parts of the MISO region for reliability purposes and how much can be imported from and exported to other locations, among other things.

MISO engages with a broad range of stakeholders to share ideas and discuss potential solutions to the challenges facing the region. The Reliability Imperative work also involves a robust, collaborative dialogue across the many forums within the stakeholder process. The collaboration that takes place in these forums has provided valuable policy and technical-related feedback, and MISO is committed to continuing that engagement.



MISO INITIATIVES ARE INTERCONNECTED AND SEQUENCED

MISO's strategic priorities are connected and build upon each other. Success in one area depends on progress in another, so efforts must be coordinated and sequenced. For example, achieving reliable and economically efficient grid operations requires new tools and processes to be developed under the Operations of the Future workstream and market enhancements to be developed under the Market Redefinition workstream.

Given the urgent and complex challenges that are facing the region, it is crucial for MISO members, states and MISO to work together to execute on the reforms that are needed.

The MISO Value Proposition

MISO creates substantial cost savings and other benefits by managing the grid system on a regional basis that spans all or parts of 15 states and one Canadian province. Before MISO was created, the system was managed by 39 separate Local Balancing Authorities (LBAs), which made the grid much more fragmented and far less economically efficient than it is today.

The benefits that MISO created in calendar year 2022 range from \$3.3 billion to \$4.5 billion, according to the [Value Proposition study](#) that MISO performs every year. That represents a benefit-to-cost ratio of about 12:1 when compared to the fees that utilities pay to be members of MISO. MISO creates benefits in a variety of ways, including through efficient dispatch and reduced need for assets. Since the Value Proposition study was launched in 2007, the cumulative benefits that MISO has created exceed \$40 billion. And notably, that figure does not reflect all the benefits MISO creates due to the conservative approach that MISO uses to conduct the study.

While continuing to use this conservative approach, MISO anticipates that it will create even more benefits going forward by helping its members and states to achieve their decarbonization goals in a reliable manner. In June 2022, MISO looked at those anticipated future benefits in a supplemental report called the [Forward View of the Value Proposition](#). That report estimates the value that MISO will create going forward in two ways that are not specifically reflected in the "standard" Value Proposition study: (1) the value of sharing carbon-free energy from areas with higher levels of renewables to regions with lower levels, and (2) the value of sharing flexibility attributes that are required to integrate those new renewables while maintaining reliability.

MISO found that by including these two additional value streams, MISO's total benefit-to-cost ratio would increase from approximately 12:1 today to approximately 26:1 by 2040. This illustrates that while there are indeed many challenges associated with fleet change, there are also tremendous economic benefits that utilities and states can realize by pursuing their decarbonization goals as members of MISO.



Informing the Reliability Imperative

MISO's response to the Reliability Imperative has been informed by years of conversations with stakeholders. MISO has also undertaken numerous studies to assess the region's changing risk profile and to explore how reliability is being affected by various drivers. This work includes:

Attributes Roadmap: This study looks at three key electric system attributes where near-term risk is most acute: (1) System Adequacy, (2) Flexibility and (3) System Stability. The Attributes Roadmap recommends advancing a combination of current and new proposals as well as providing ongoing attributes visibility through regular reporting.



Renewable Integration Impact Assessment (RIIA): This study assesses the impacts of integrating increasingly higher levels of renewables into the MISO system. RIIA indicates that planning and operating the grid will become significantly more complex when greater than 30% of load is served by wind and solar. However, RIIA also indicates that renewable penetrations of greater than 50% could be reliably achieved if utilities, states, and MISO coordinate closely on needed actions.



Regional Resource Assessment (RRA): The RRA is a recurring study based on the plans and goals MISO members have publicly announced for their generation resources. The RRA aggregates these plans and goals to develop an indicative view of how the region's resource mix might evolve to meet utilities' stated objectives. The RRA aims to help utilities and states identify new and shifting risks years before they materialize, creating a window to develop cost-effective solutions.



MISO Futures: The MISO Futures utilize a range of economic, policy and technological inputs to develop three future scenarios that "bookend" what the region's resource mix might look like in 20 years. The Futures inform the development of transmission plans and help MISO prioritize work under the Reliability Imperative. Series 1 was published in 2021. In 2023, MISO updated the report to Series 1A to reflect evolving member/state plans and the clean energy incentives in the Inflation Reduction Act, among other things.



Markets of the Future: This report illustrates how and when MISO's market structures will need to evolve in order to accommodate the transformation of the energy sector. The needs are presented in four broad categories: (1) Uncertainty and Variability, (2) Resource Models and Capabilities, (3) Location and (4) Coordination. This report helped establish the foundation for the work MISO is currently doing to identify critical system attributes.



The February (2021) Arctic Event: This report discusses lessons learned from Winter Storm Uri, which affected the MISO region and other parts of the country in February 2021. MISO and its members took emergency actions during the event to prevent more widespread grid failures. Uri illustrated how extreme weather can exacerbate the challenges of fleet change. Preparing for extreme weather is a major part of MISO's response to the Reliability Imperative.





Electrification Insights: This report explores the challenges and opportunities the grid could face from the growth of electric vehicles and the increasing electrification of other sectors of the economy, such as homes and businesses. The report indicates electrification could transform the MISO grid from a summer-peaking to a winter-peaking system, and that vehicle charging and daily heating and cooling load could result in two daily power peaks nearly all year.



From this groundwork, we know there are many challenges ahead. But we also believe we can respond to the Reliability Imperative in a manner that enables our members to achieve their resource plans and policy objectives. We are determined to do the hard work required to ensure our members benefit from MISO membership.

Acronyms Used in This Report

DER: Distributed Energy Resource

FERC: Federal Energy Regulatory Commission

GW: Gigawatt

JTIQ: Joint Targeted Interconnection Queue

LBA: Load Balancing Authority

LSE: Load Serving Entity

LRTP: Long Range Transmission Planning

MSC: Market Subcommittee

MISO: Midcontinent Independent System Operator

MSE: Market System Enhancement

MTEP: MISO Transmission Expansion Plan

MW: Megawatt

NERC: North American Electric Reliability Corporation

OMS: Organization of MISO States

PAC: Planning Advisory Committee

PRA: Planning Resource Auction

PRM: Planning Reserve Margin

RBDC: Reliability-Based Demand Curve

RIIA: Renewable Integration Impact Assessment

RRA: Regional Resource Assessment

SPP: Southwest Power Pool

The copyright in all material published in this report by the Midcontinent Independent System Operator, Inc. (MISO), including all portions of the content, design, text, graphics and the selection and arrangement of the material within the report (the “material”), is owned by MISO, or legally licensed to MISO, unless otherwise indicated. The material may not be reproduced or distributed, in whole or in part, without the prior written permission of MISO. Any reproduction or distribution, in whatever form and by whatever media, is expressly prohibited without the prior written consent of MISO.

© 2024 MISO. All rights reserved.



2025 OMS-MISO Survey Results

Furthering our joint commitment to regional resource adequacy, OMS and MISO are pleased to announce the results of the 2025 OMS-MISO Survey

June 6, 2025

Updated 6/6/2025: Slide 21

The 2025 OMS-MISO Survey reinforces near-term risks and highlights key uncertainties impacting resource adequacy

- Projections result in a potential surplus ranging from 1.4 GW to 6.1 GW for summer 2026. At least 3.1 GW* of additional capacity beyond the committed capacity will be needed to meet the projected planning reserve margin forecast.
- Queue and market reforms, improved resource deployment timelines and other initiatives will help maintain resource adequacy through 2031.
 - Replacement and surplus queue projects will mitigate the impact of retirements by using existing interconnection service, supplying ~25% of new capacity additions.
- As solar penetration grows, reliability risks are spreading into winter from summer.
- Load growth, driven by economic development, is outpacing previous forecasts with a 2.2% compound annual growth rate over five years.
- Resource accreditation reforms (e.g., Direct Loss of Load in PY 2028/29) are expected to provide a clearer view of resource adequacy, system-level outlooks remain consistent with current methods.

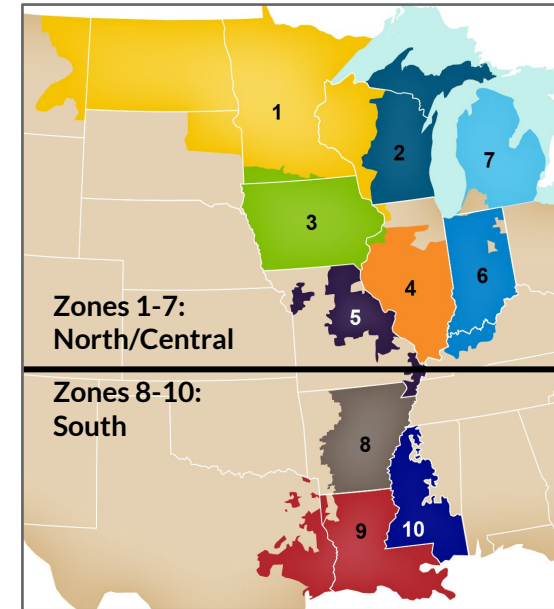
All references to capacity in this presentation indicate seasonal accredited capacity (SAC), unless noted otherwise.

**See slide 7 for data which illustrates the projected Planning Reserve Margin Requirement with Load Serving Entities' forecast (137.3 GW) minus Committed Capacity (134.2) for PY 2026/27.*

The OMS-MISO Survey provides a resource adequacy view over a five-year horizon based on currently available information

The survey* results indicate the degree to which expected capacity resources satisfy planning reserve margin requirements with either a surplus or a deficit

- 91% of existing generation participated in the 2025 OMS-MISO Survey, representing 97.4% of MISO load.
- Various projected capacity scenarios and large spot-load additions highlight the increasing uncertainty and evolving risk.
- Load Serving Entities (LSEs) are expected to have adequate resources to meet load reserve requirements in each zone.
- MISO zonal views are not included this year as the annual capacity import limit and capacity export limit study will provide value updates and be reported in the Loss of Load Expectation report in November.



Additional factors can impact projected deficits or surpluses that are observed in the survey



Downside Risks

- Winter reliability risk intensifies due to low solar accreditation during the season
- Rapid industrial and commercial growth adds pressure on resource adequacy
- Continued backlog and uncertainty in generation queue (296 GW) complicates timely resource additions
 - 54 GW of signed Generation Interconnection Agreements (GIAs) not yet online (71% of which are wind and solar)
- Accelerated pace of resource retirements is driven by regulatory pressures, economic pressures and aging infrastructure
- Persistent supply-chain disruptions, labor constraints and permitting challenges delay new resource deployments



Upside Possibilities

- Market reforms, including Reliability-Based Demand Curve and accreditation updates, provide clearer and stronger investment signals
- Enhanced forecasting methods recognizing replacement/surplus units improve accuracy and confidence
- Queue reforms reduce speculative projects and streamline resource integration processes
- Retirement deferrals offer a potential short-term reliability buffer against seasonal projected capacity shortfalls
- Easing of supply, labor, or permitting constraints could speed deployments

Summer Seasonal Accreditation Values

Resource Category	2025 Survey	2024 Survey
 Potentially Unavailable Resources	No Changes	- Indicated as “Low Certainty” in survey results by market participants - Includes potential retirements or suspensions - Assumes resources will not be used to meet PRMR
 Potential New Capacity – New Point of Interconnection	Historical Projection: Results in 3.5 GW/yr <i>Driven by 2022-2024 actuals</i> Emerging Projection: Results in 6.2 GW/yr average <i>Informed by member responses to OMS-MISO Survey request, these members represent 97% of the load in the footprint</i> <i>Fuel mix of new resources indicated by OMS-MISO Survey member responses</i>	Using 3-Year Historical Average: Capacity addition (2.3 GW/yr) based on the average new capacity built in Planning Years 2020-2022 Using Alternative Projection: Informed by timing estimates from interconnection customers with signed Generator Interconnection Agreement projects* (6.1 GW/yr) - Assumes resources will be used to meet PRMR
 Replacement/ Surplus Project Impact Potential New Capacity – Existing Point of Interconnection	Replacement Impact Highlighted: Results in additional “new resources” to offset the impacts of retirements Historical Replacement : Valued at 1.2 GW/yr <i>50% replacement & surplus queue adoption</i> Emerging Replacement: Valued at 2.4 GW/yr <i>100% replacement & surplus queue adoption</i> <i>The replacement queue is not directly part of MISO’s queue cycle methodology, and until recently the adoption rate of future replacement resources was unknown</i>	Not included
 Committed Capacity	No Changes	- Existing generation resources - External resources with firm contracts to MISO load - Assumes resources will be used to meet PRMR

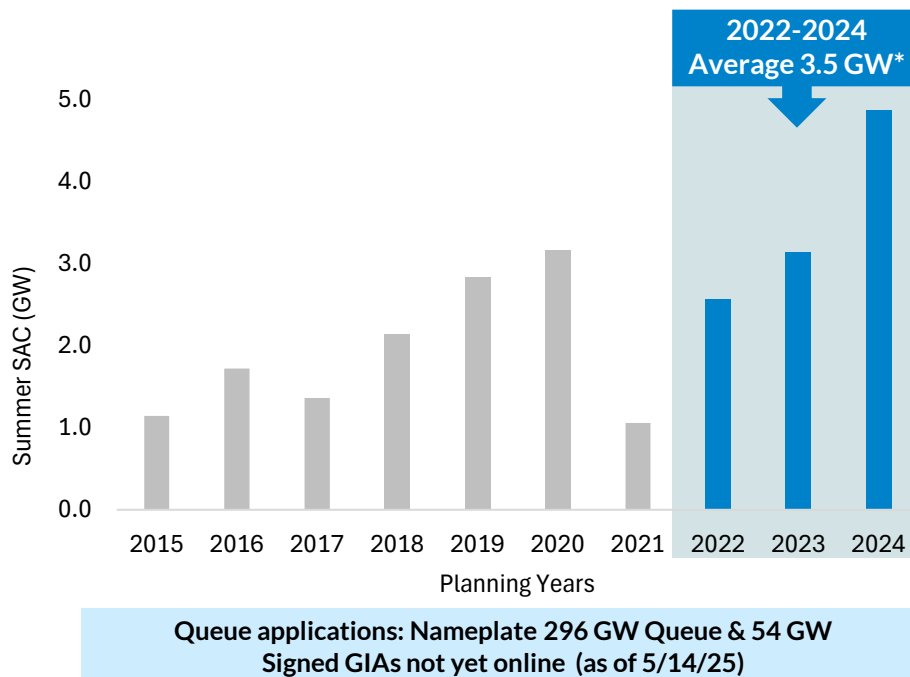
Trends and market pressures related to new capacity additions suggest that refinements are needed to better reflect uncertainty

Previously, MISO used probability-adjusted estimates for projects in various queue phases. Due to the significantly larger queue and constraints on projects with signed Generation Interconnection Agreements (GIAs), this approach no longer applies. As in 2024, the 2025 survey employs two estimates:

- 1. Three-Year Historical Average:** based on the historical rate of additions per planning year*
- 2. Emerging Projection:** based on member submittals to the OMS-MISO Survey

These projections are combined with the MISO Surplus and Replacement Queues to create bookend capacity forecasts for the MISO footprint.

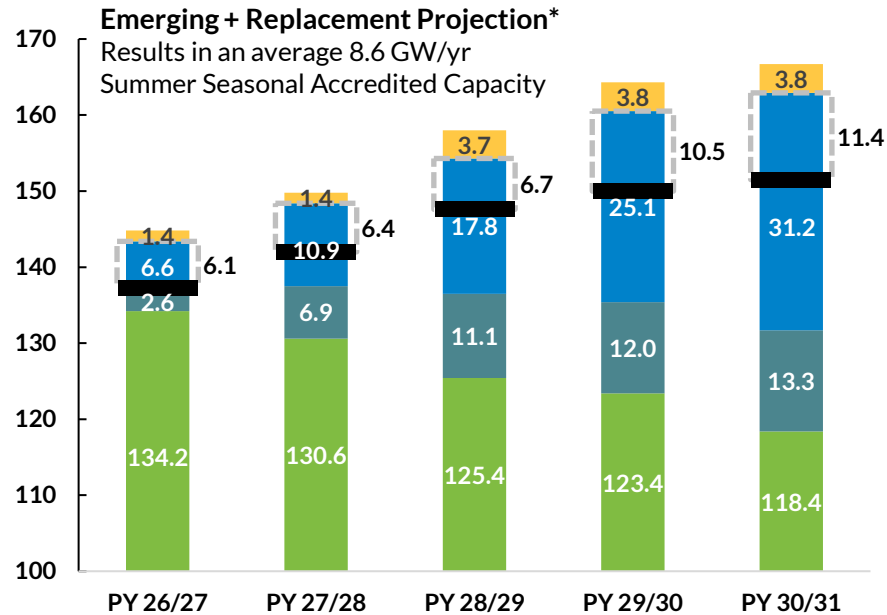
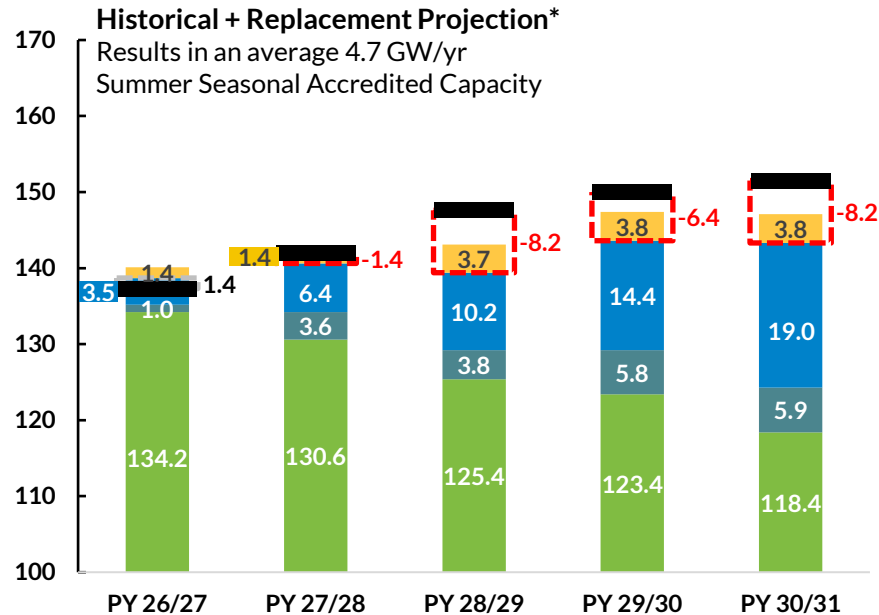
The scale and pace of new resource additions have varied over time



Historical + Replacement & Emerging + Replacement Projections vs PRMR

~4.7 GW & 8.6 GW Status Quo Summer SAC Installation Rate

MISO Resource Adequacy Projections – Summer



- Projected PRMR with LSE forecast
- Potentially Unavailable Resources
- Potential New Capacity
- Value of Replacement/Surplus Projects
- Committed Capacity

*Using methods for potential New Capacity described on Slide 5

PRMR: Planning Reserve Margin Requirement

Red border values indicate the additional potential deficit against the Projected PRMR

Gray border values indicate the potential surplus against the Projected PRMR

- Capacity accreditation values and Planning Reserve Margin projections based on current practices
- Regional Directional Transfer (RDT) limit of 1900 MW is reflected in this chart

Winter Seasonal Accreditation Values

Resource Category	2025 Survey	2024 Survey
 Potentially Unavailable Resources	No Changes	- Indicated as “Low Certainty” in survey results by market participants - Includes potential retirements or suspensions - Assumes resources will not be used to meet PRMR
 Potential New Capacity – New Point of Interconnection	Historical Projection: Results in 1.4 GW/yr <i>Driven by 2022-2024 actuals</i> Emerging Projection: Results in 4.1 GW/yr average <i>Informed by member responses to OMS-MISO Survey request, these members represent 97% of the load in the footprint</i> <i>Fuel mix of new resources indicated by OMS-MISO Survey member responses</i>	Not included
 Replacement/ Surplus Project Impact Potential New Capacity – Existing Point of Interconnection	Replacement Impact Highlighted: Results in additional “new resources” to offset the impacts of retirements Historical Replacement : Valued at 1.0 GW/yr <i>50% replacement & surplus queue adoption</i> Emerging Replacement : Valued at 2.1 GW/yr <i>100% replacement & surplus queue adoption</i> <i>The replacement queue is not directly part of MISO’s queue cycle methodology, and until recently the adoption rate of future replacement resources was unknown</i>	Not included
 Committed Capacity	No Changes	- Existing generation resources - External resources with firm contracts to MISO load - Assumes resources will be used to meet PRMR

PRMR: Planning Reserve Margin Requirement

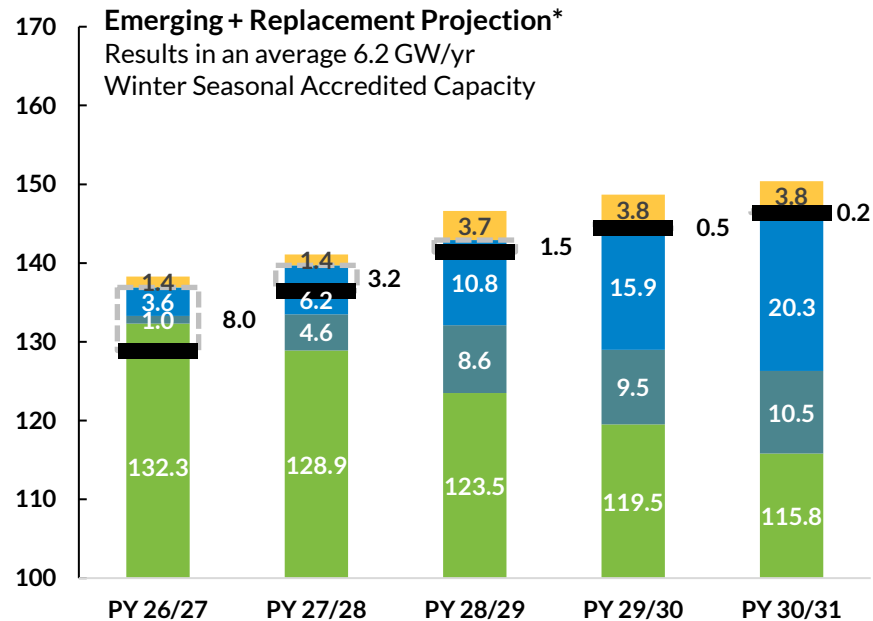
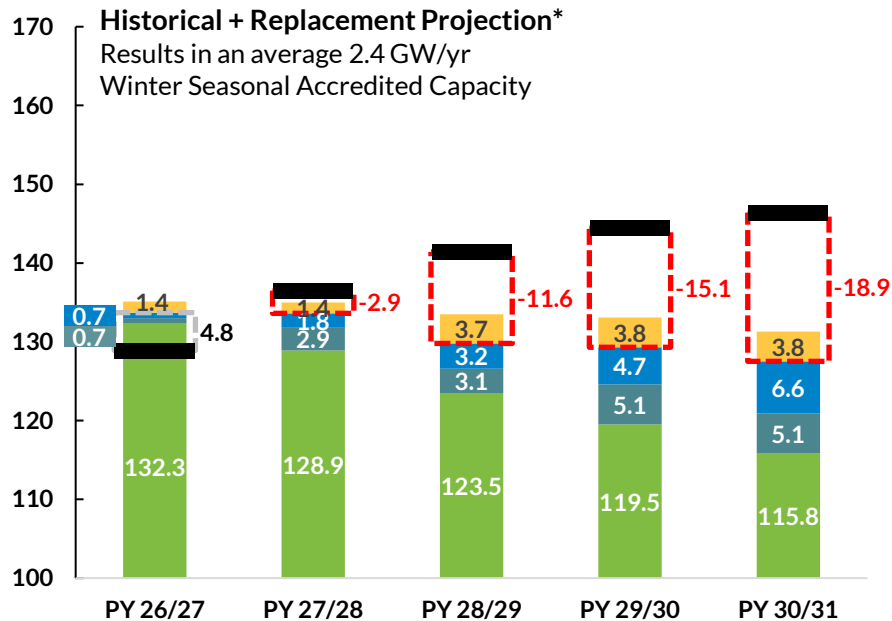
Committed Capacity: Resources committed to serving MISO’s load

Potentially Unavailable Resources: May be available to serve MISO’s load but may not have firm commitments

Historical + Replacement & Emerging + Replacement Projections vs PRMR

~2.4 GW & 6.2 GW Status Quo Winter SAC Installation Rate

MISO Resource Adequacy Projections – Winter



- Projected PRMR with LSE forecast
- Potentially Unavailable Resources
- Potential New Capacity
- Value of Replacement/Surplus Projects
- Committed Capacity

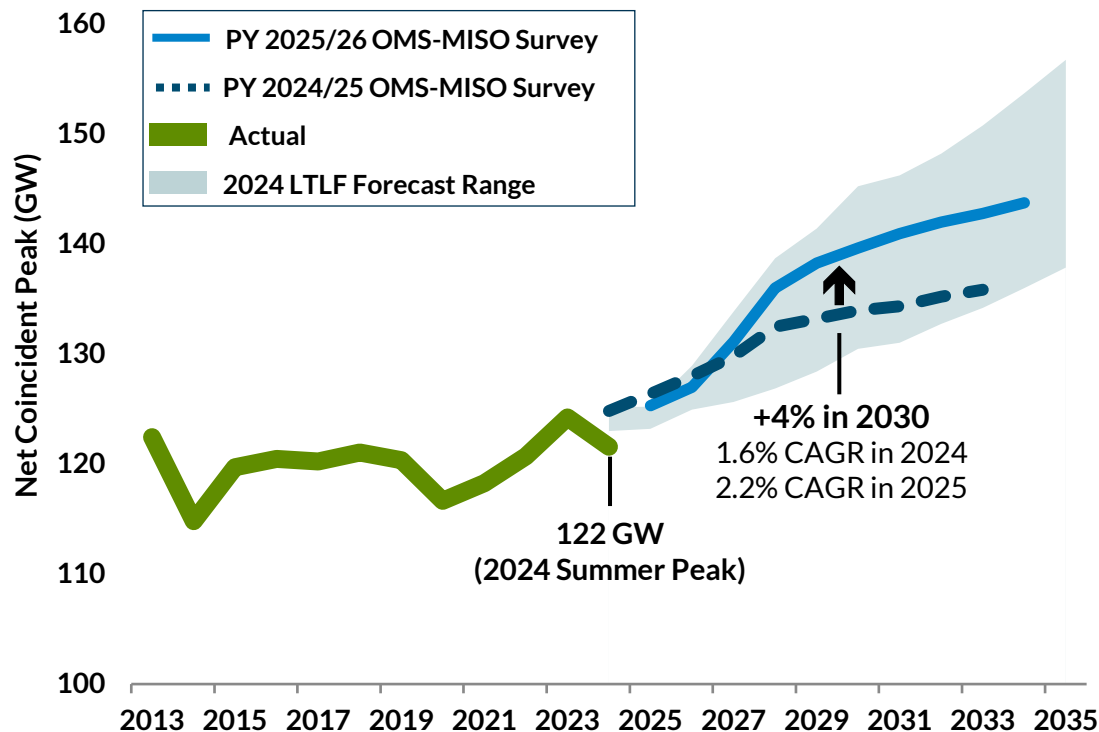
*Using methods for potential New Capacity described on Slide 8
PRMR: Planning Reserve Margin Requirement

Red border values indicate the additional potential deficit against the Projected PRMR
Gray border values indicate the potential surplus against the Projected PRMR

- Capacity accreditation values and Planning Reserve Margin projections based on current practices
- Regional Directional Transfer (RDT) limit of 1900 MW is reflected in this chart



OMS-MISO Survey responses show increasing load forecasts year-over-year and are close to the high end of MISO Long-Term Load Forecast



- Load growth through 2035 will exacerbate capacity shortfall and operational risks
- Many new loads will require additional firm, controllable resources

Anticipated Impact in MISO's region 2024-44 Growth TWh Low-High*



- High
- Data Centers (149-241)
- Electric Vehicles (54-91)
- Industry Development & Offshoring (21-105)
- Hydrogen (25-95)
- Low
- Building Electrification (36-43)

NEW: The 2025 OMS-MISO Survey includes sensitivities considering a range of new, large spot-load additions



PY 28/29

*Illustrative example:
PY 2026/27 using three-
year historical average*

PRMR based on Long-Term Load Forecast "High Trajectory"

- Models higher load-growth scenario per Long Term Load Forecast¹
- Red dashed border values = deficit; gray dashed border values = surplus

PRMR based on LSE submitted load forecast

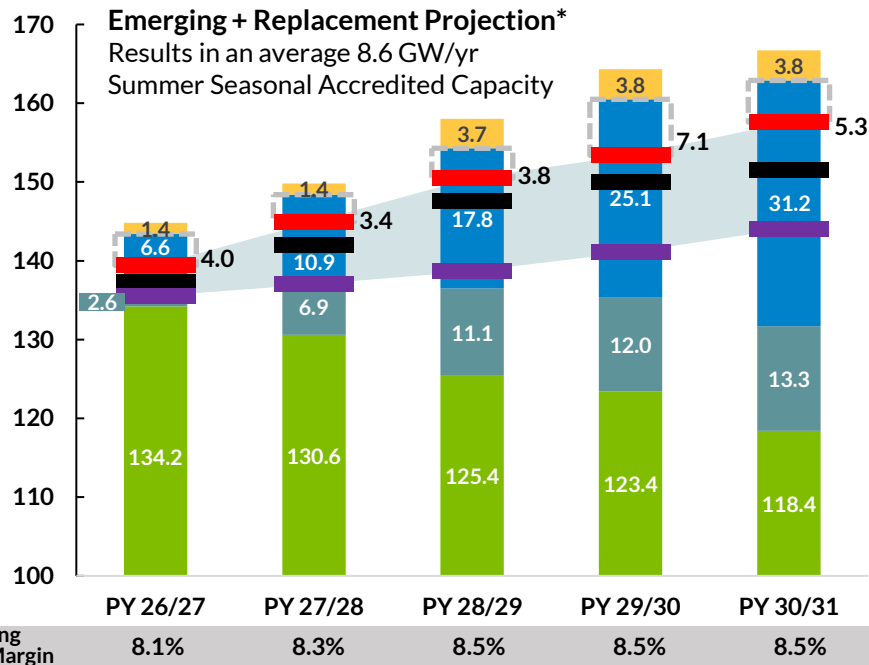
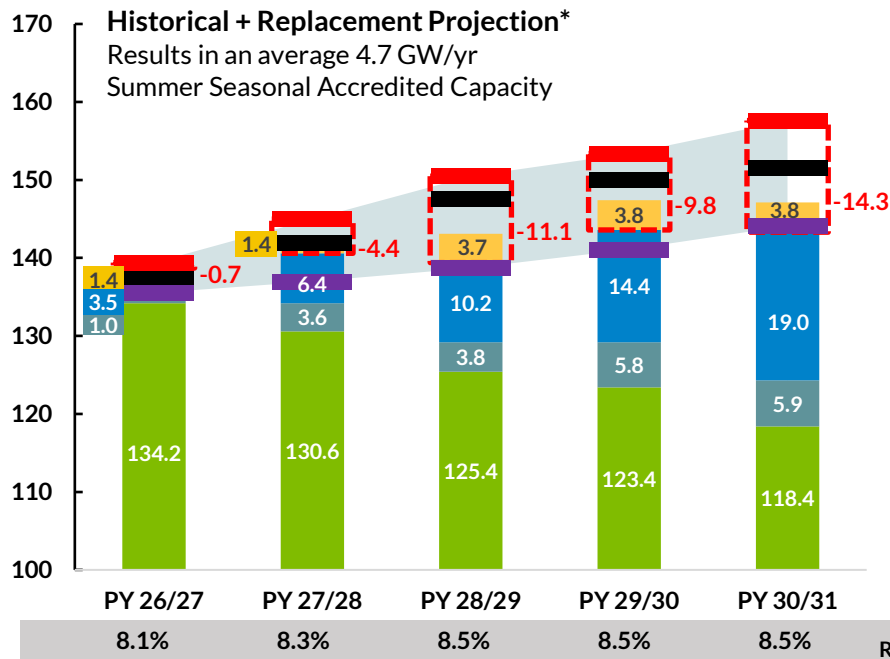
- LSE-submitted Non-Coincident Peak Forecast (NCPF) converted to Coincident Peak Forecast (CPF) using MISO-posted coincidence factors
- Transmission losses added
- PRMR calculated using out year PRM% from PY 2025/26 LOLE Study

PRMR based on Long-Term Load Forecast "Current Trajectory"

- Models lower load-growth scenario per Long-Term Load Forecast¹

Capacity deficits continue to grow in the near and long term under a large spot-load additions scenario

MISO Resource Adequacy Projections – Summer



- Projected PRMR for 'High Trajectory' scenario
- Projected PRMR for 'Current Trajectory' scenario
- Projected PRMR with LSE forecast
- Potentially Unavailable Resources
- Potential New Capacity
- Value of Replacement/Surplus Projects
- Committed Capacity

- Shaded area indicates spread between projected PRMR for "Current Trajectory" and "High Trajectory" scenario from Long-term Load Forecast
- Red border values indicate the additional potential deficit with "High Trajectory" scenario case
- Gray border values indicate the potential surplus with "High Trajectory" scenario case
- *Capacity accreditation values and Planning Reserve Margin projections based on current practices
- *Using Potential New Capacity as described on Slide 5.
- PRMR: Planning Reserve Margin Requirement



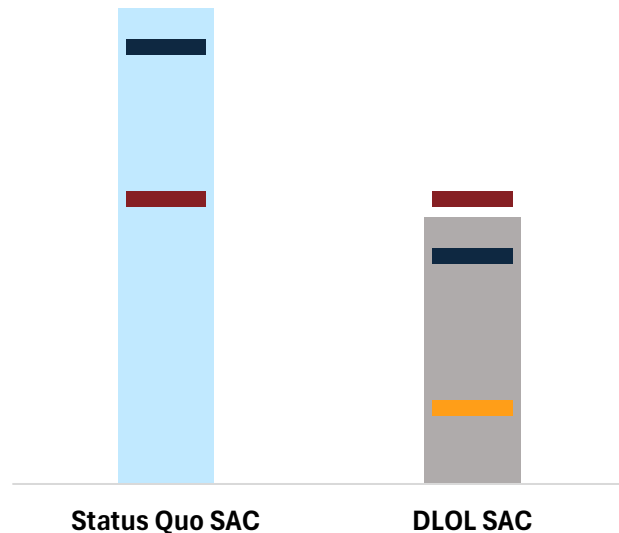
MISO's existing accreditation methods can overstate a resource's capacity value during the highest risk periods, especially as the region's risk profile changes, leading to understated risk

- Increased reliance on wind, solar and storage, projected large-load additions and electrification, and frequent large-scale weather events are decoupling periods of risk from periods of high demand.
- These drivers are upending traditional methods for establishing reliability requirements and resource accreditation.
- MISO's resource accreditation methodology* (Direct Loss of Load) will value a resource's marginal contribution to reliability during the highest risk periods.

MISO's accreditation reforms, targeted for implementation in PY 2028/29, will better measure a resource's contribution to reliability.

High Level Description of Status Quo vs Direct Loss of Load

Comparing Accreditation for Status Quo & DLOL SAC



Peak Load Forecast

- Submitted annually by members

Critical Hours Load Forecast

- Illustrative only, not collected

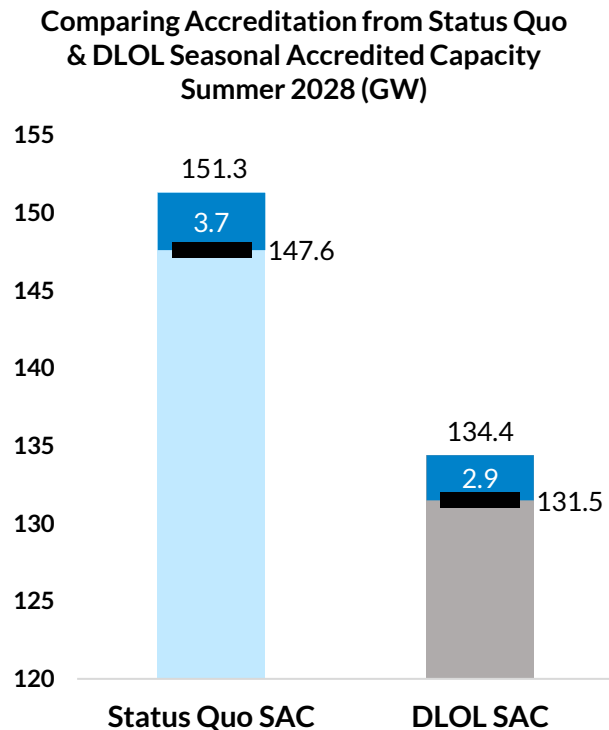
Planning Reserve Margin Requirement (PRMR) at

- Status Quo: Peak Load
- DLOL: critical hours

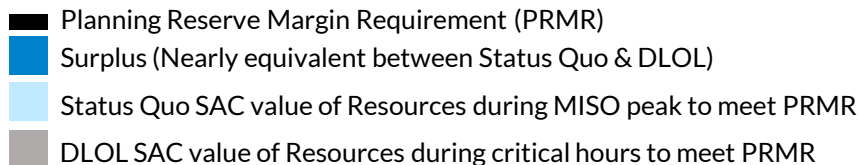
Status Quo SAC value of Resources during MISO peak to meet PRMR

DLOL SAC value of Resources during critical hours to meet PRMR

Status Quo vs Direct Loss of Load Accreditation for summer 2028



- In principle, surplus/deficit moving from status quo to DLOL SAC should remain unchanged
- Modeled load and resource mix that is misaligned from OMS-MISO Survey results will cause deviations in surplus/deficit
- PY 2028/29 was most comparable in load and resource mix, which is why DLOL view is only shown for one year



MISO has acted on many Reliability Imperative initiatives to address resource adequacy challenges, but there's more to be done

Ongoing Challenges

- Accelerating demand for electricity
- Rapid pace of generation retirements continue
- Loss of accredited capacity and reliability attributes
- Intermittent nature of new resource additions
- Delays of new resource additions
- More frequent extreme weather

Completed Initiatives

- ✓ Implemented Reliability-Based Demand Curve in 2025 PRA
- ✓ Generation interconnection queue cap
- ✓ Improved generator interconnection queue process (*New application portal June 2025*)
- ✓ Approved over \$30 billion in new transmission lines

Initiatives In Progress

- ❑ Implement interim Expedited Resource Addition Study (ERAS) process (2025)
- ❑ Implement Direct Loss of Load (DLOL)-based accreditation (PY 2028/29)
- ❑ Enhance resource adequacy risk modeling
- ❑ Reduce queue cycle times through automation
- ❑ Demand Response and Emergency Resource reforms
- ❑ Enhance allocation of resource adequacy requirements

The 2025 OMS-MISO Survey emphasizes that decisions made today by utilities, regulators, MISO and its members will critically shape future resource adequacy

- This year's survey highlights significant uncertainty in projected resource adequacy, underscoring the urgent need for accelerated resource additions, strategic retirement planning, and proactive management of increasing load growth.
- Ongoing collaboration between OMS and MISO remains essential to address intensifying reliability risks, particularly as seasonal challenges, especially in winter, grow increasingly complex.
- Continued and immediate actions are required to streamline the addition of new capacity, align resources effectively with new load demands.
- MISO's ongoing resource adequacy reforms remain critical and responsive, directly addressing evolving reliability challenges.

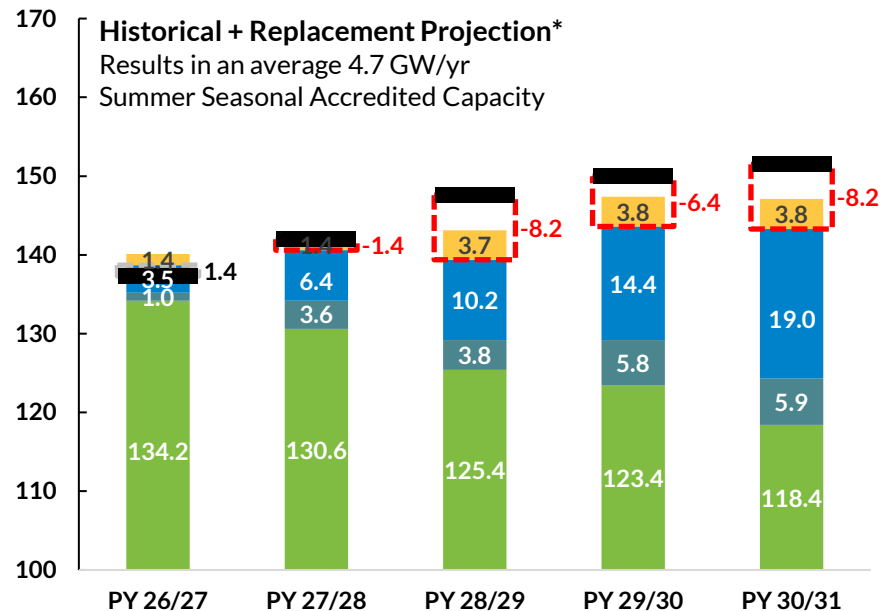
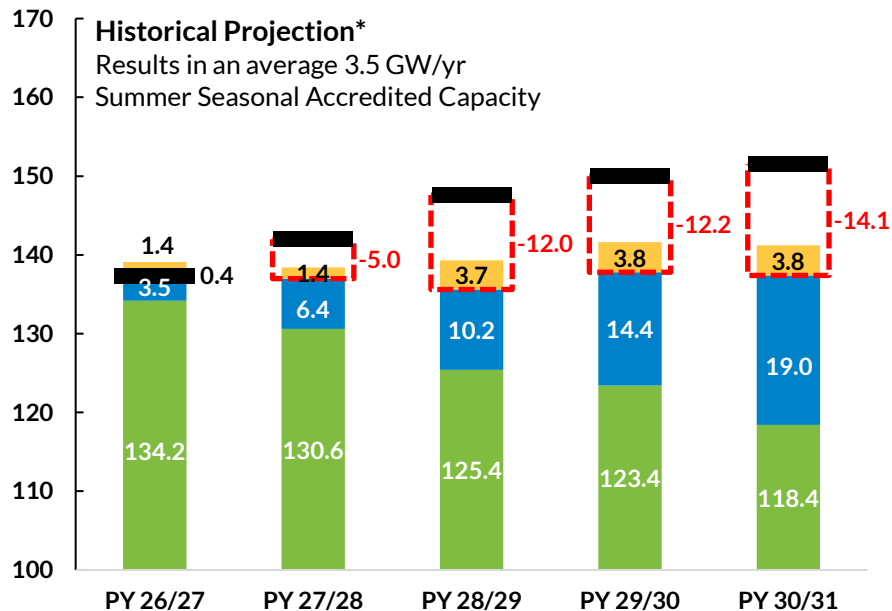
Appendix



Historical & Historical + Replacement Projections vs PRMR

~3.5 GW & 4.7 GW Status Quo Summer SAC Installation Rate

MISO Resource Adequacy Projection – Summer



- Projected PRMR with LSE forecast
- Potentially Unavailable Resources
- Potential New Capacity
- Value of Replacement/Surplus Projects
- Committed Capacity

*Using methods for potential New Capacity described on Slide 5
PRMR: Planning Reserve Margin Requirement

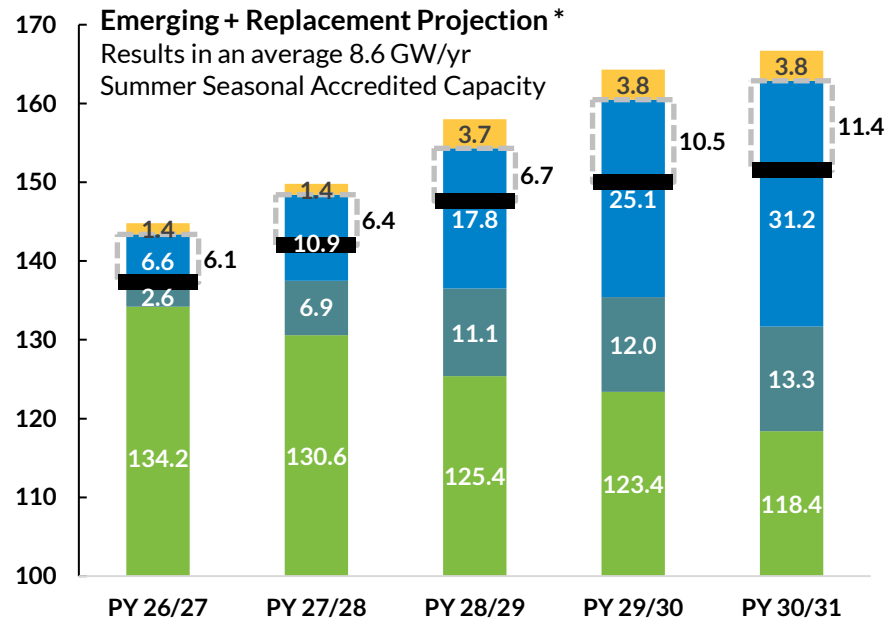
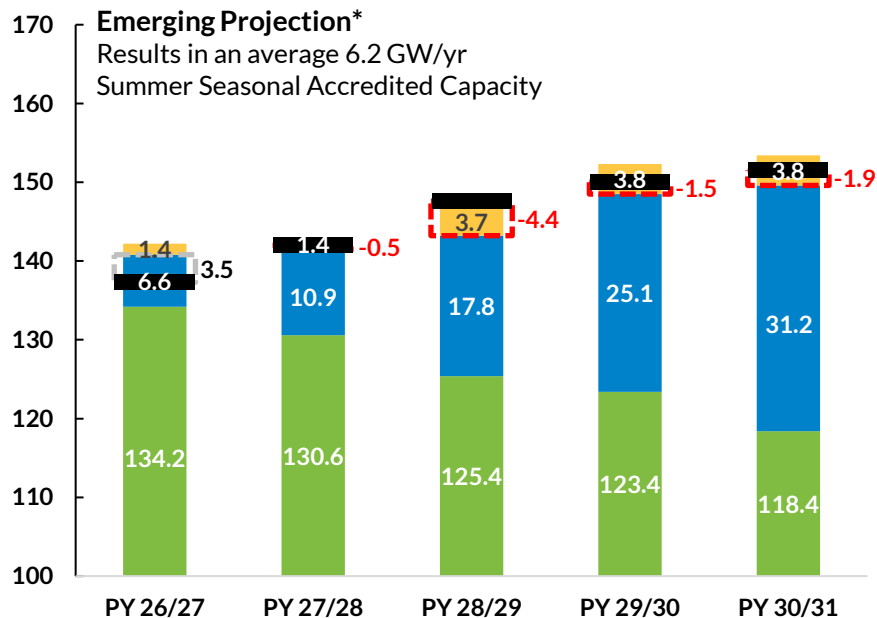
- Red border values indicate the additional potential deficit against the Projected PRMR
- Gray border values indicate the potential surplus against the Projected PRMR

- Capacity accreditation values and Planning Reserve Margin projections based on current practices
- Regional Directional Transfer (RDT) limit of 1900 MW is reflected in this chart

Emerging & Emerging + Replacement Projections vs PRMR

~6.2 GW & 8.6 GW Status Quo Summer SAC Installation Rate

MISO Resource Adequacy Projection – Summer



- Projected PRMR with LSE forecast
- Potentially Unavailable Resources
- Potential New Capacity
- Value of Replacement/Surplus Projects
- Committed Capacity

*Using methods for potential New Capacity described on Slide 5
PRMR: Planning Reserve Margin Requirement

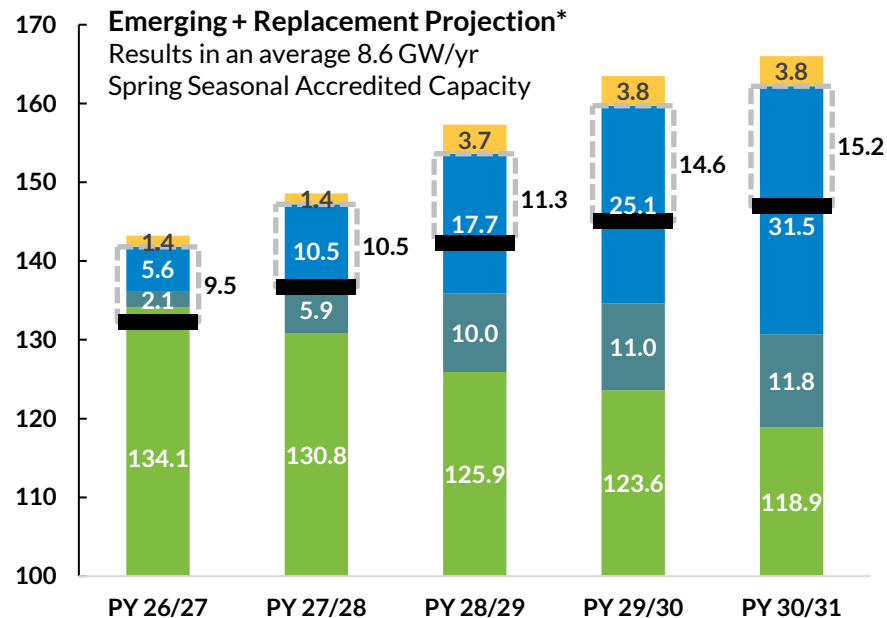
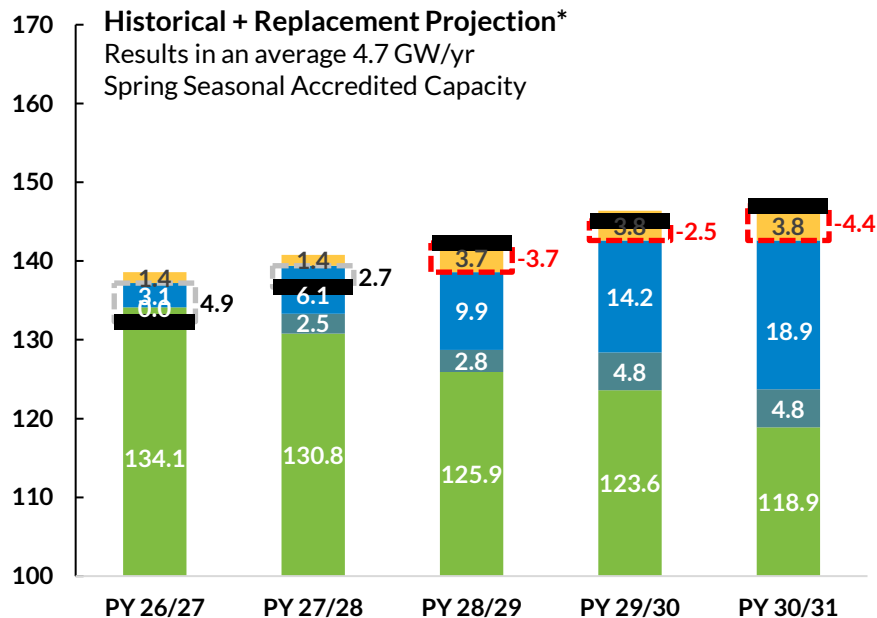
- Red border values indicate the additional potential deficit against the Projected PRMR
- Gray border values indicate the potential surplus against the Projected PRMR

- Capacity accreditation values and Planning Reserve Margin projections based on current practices
- Regional Directional Transfer (RDT) limit of 1900 MW is reflected in this chart

Historical + Replacement & Emerging + Replacement Projections vs PRMR

~4.7 GW & 8.6 GW Status Quo Fall SAC Installation Rate

MISO Resource Adequacy Projection – Fall



- Projected PRMR with LSE forecast
- Potentially Unavailable Resources
- Potential New Capacity
- Value of Replacement/Surplus Projects
- Committed Capacity

*Using methods in line with potential New Capacity described on Slide 5
PRMR: Planning Reserve Margin Requirement

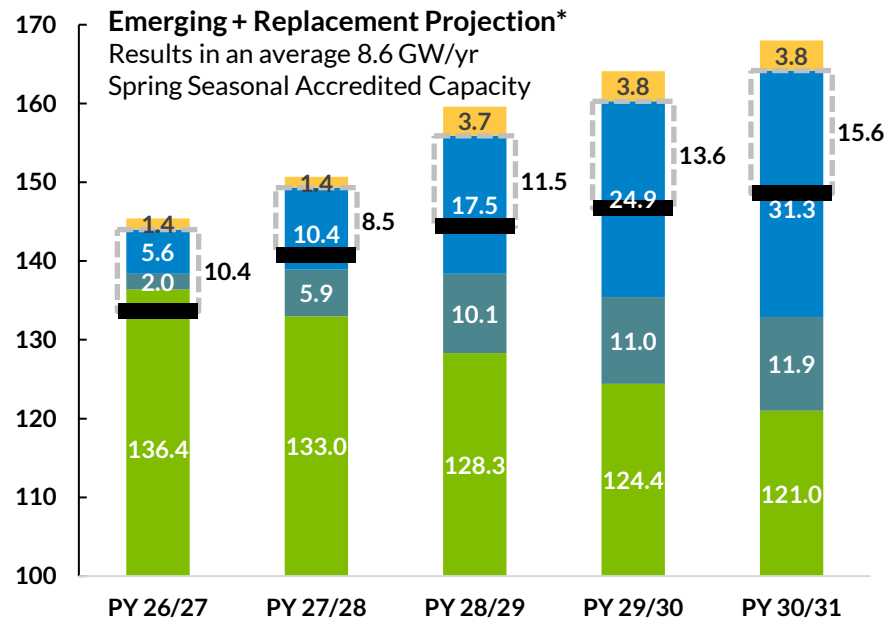
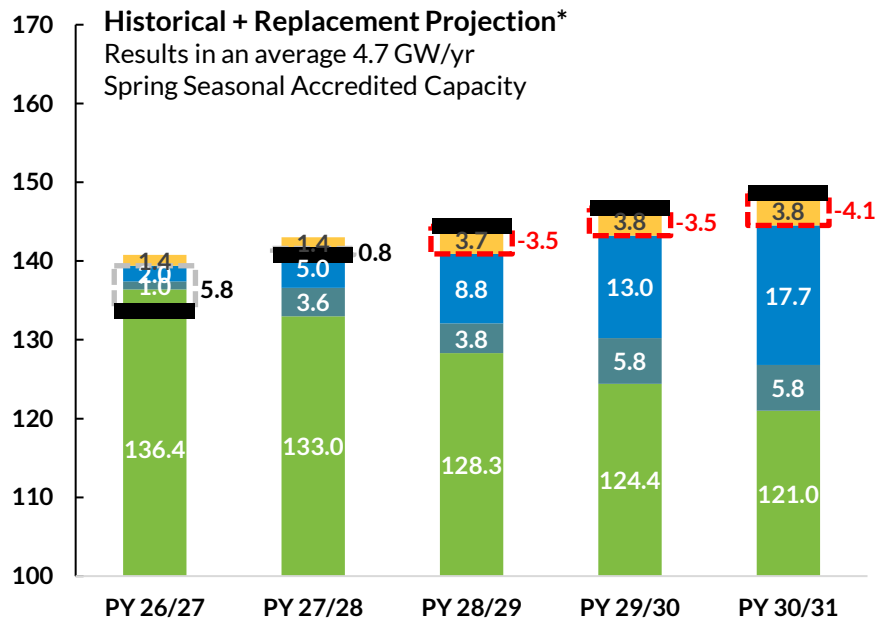
- Red border values indicate the additional potential deficit against the Projected PRMR
- Gray border values indicate the potential surplus against the Projected PRMR

- Capacity accreditation values and Planning Reserve Margin projections based on current practices
- Regional Directional Transfer (RDT) limit of 1900 MW is reflected in this chart

Historical + Replacement & Emerging + Replacement Projections vs PRMR

~4.7 GW & 8.6 GW Status Quo Spring SAC Installation Rate

MISO Resource Adequacy Projection – Spring



- Projected PRMR with LSE forecast
- Potentially Unavailable Resources
- Potential New Capacity
- Value of Replacement/Surplus Projects
- Committed Capacity

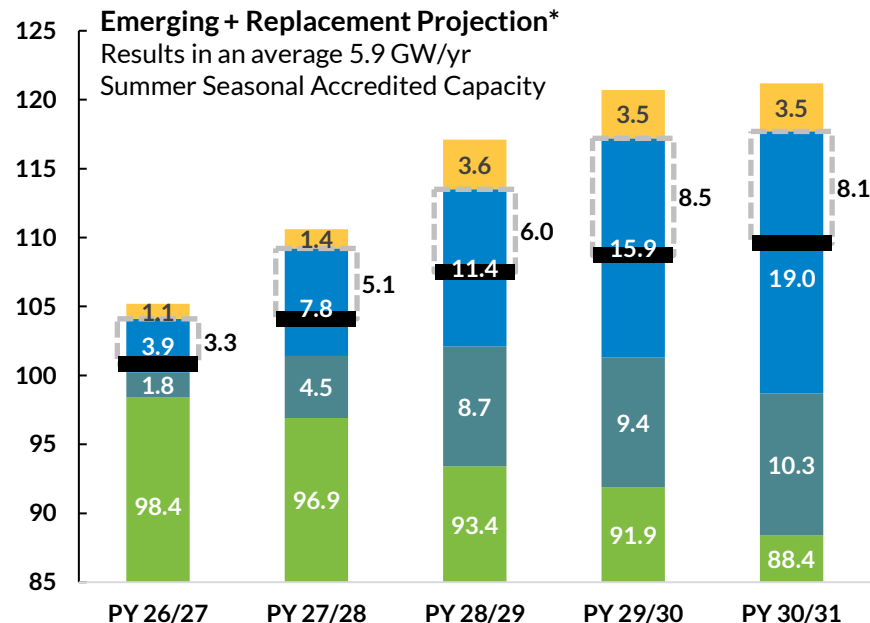
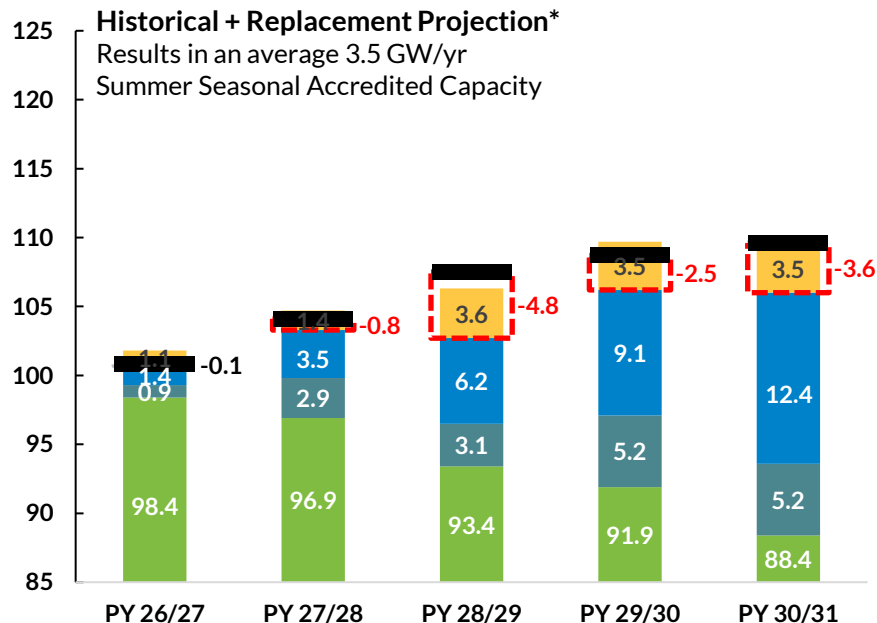
*Using methods in line with potential New Capacity described on Slide 5
PRMR: Planning Reserve Margin Requirement

- Red border values indicate the additional potential deficit against the Projected PRMR
- Gray border values indicate the potential surplus against the Projected PRMR

- Capacity accreditation values and Planning Reserve Margin projections based on current practices
- Regional Directional Transfer (RDT) limit of 1900 MW is reflected in this chart

Historical + Replacement & Emerging + Replacement Projections vs PRMR ~4.7 GW & 8.6 GW Status Quo Summer SAC Installation Rate

MISO Resource Adequacy Projections – Summer MISO North/Central



- Projected PRMR with LSE forecast
- Potentially Unavailable Resources
- Potential New Capacity
- Value of Replacement/Surplus Projects
- Committed Capacity

*Using methods for potential New Capacity described on Slide 5
PRMR: Planning Reserve Margin Requirement

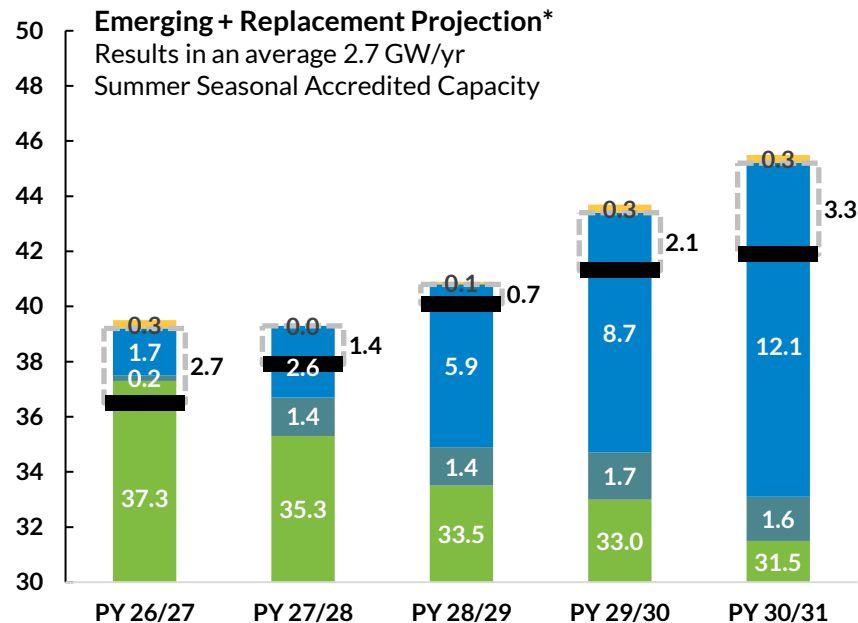
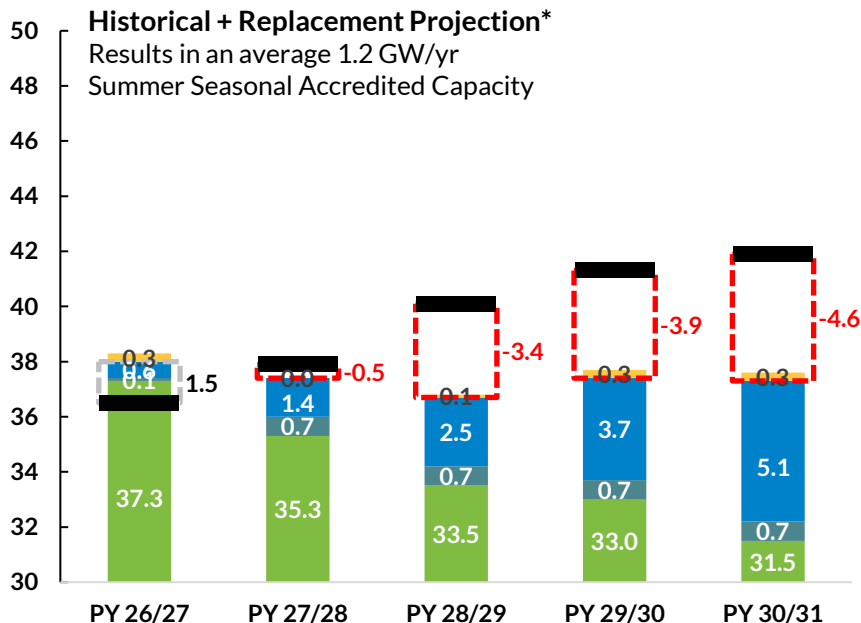
- Red border values indicate the additional potential deficit against the Projected PRMR
- Gray border values indicate the potential surplus against the Projected PRMR

- Capacity accreditation values and Planning Reserve Margin projections based on current practices
- Regional Directional Transfer (RDT) limit of 1900 MW is reflected in this chart

Historical + Replacement & Emerging + Replacement Projections vs PRMR

~4.7 GW & 8.6 GW Status Quo Summer SAC Installation Rate

MISO Resource Adequacy Projections – Summer MISO South



- Projected PRMR with LSE forecast
- Potentially Unavailable Resources
- Potential New Capacity
- Value of Replacement/Surplus Projects
- Committed Capacity

*Using methods for potential New Capacity described on Slide 5

PRMR: Planning Reserve Margin Requirement

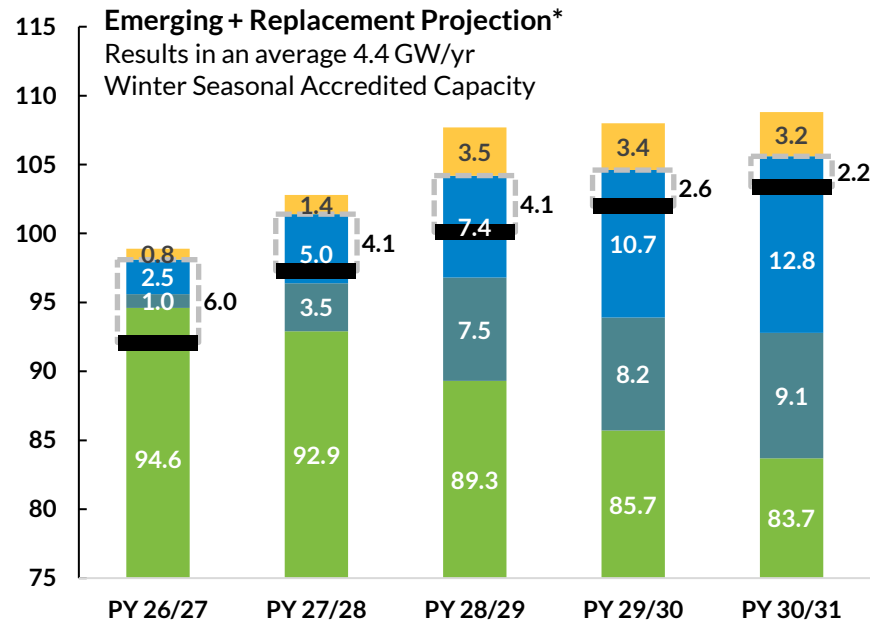
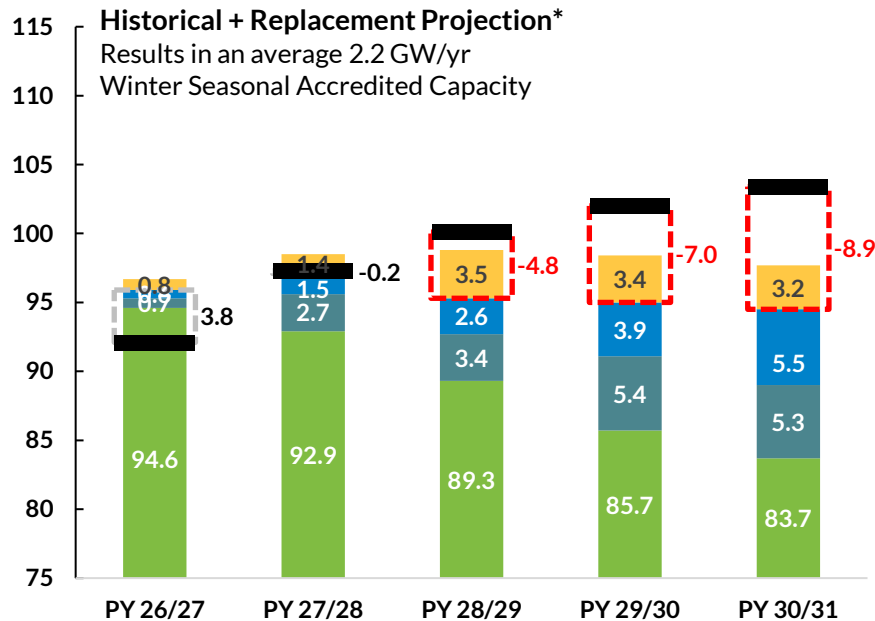
Red border values indicate the additional potential deficit against the Projected PRMR

Gray border values indicate the potential surplus against the Projected PRMR

- Capacity accreditation values and Planning Reserve Margin projections based on current practices
- Regional Directional Transfer (RDT) limit of 1900 MW is reflected in this chart

Historical + Replacement & Emerging + Replacement Projections vs PRMR ~2.4 GW & 6.2 GW Status Quo Winter SAC Installation Rate

MISO Resource Adequacy Projections – Winter MISO North/Central



*Using methods for potential New Capacity described on Slide 8

PRMR: Planning Reserve Margin Requirement

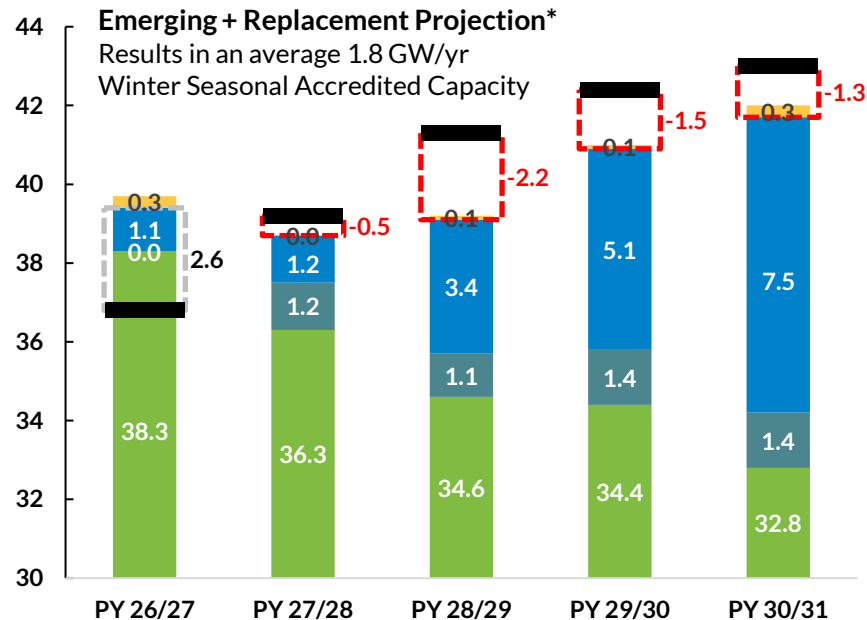
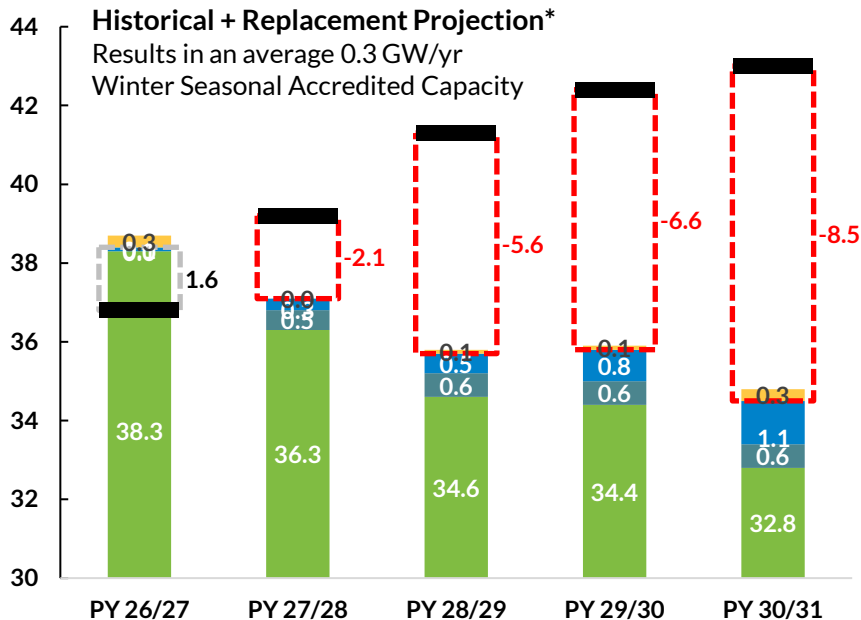
- Red border values indicate the additional potential deficit against the Projected PRMR
- Gray border values indicate the potential surplus against the Projected PRMR

- Capacity accreditation values and Planning Reserve Margin projections based on current practices
- Regional Directional Transfer (RDT) limit of 1900 MW is reflected in this chart



Historical + Replacement & Emerging + Replacement Projections vs PRMR ~2.4 GW & 6.2 GW Status Quo Winter SAC Installation Rate

MISO Resource Adequacy Projections – Winter MISO South



*Using methods for potential New Capacity described on Slide 8

PRMR: Planning Reserve Margin Requirement

- Red border values indicate the additional potential deficit against the Projected PRMR
- Gray border values indicate the potential surplus against the Projected PRMR

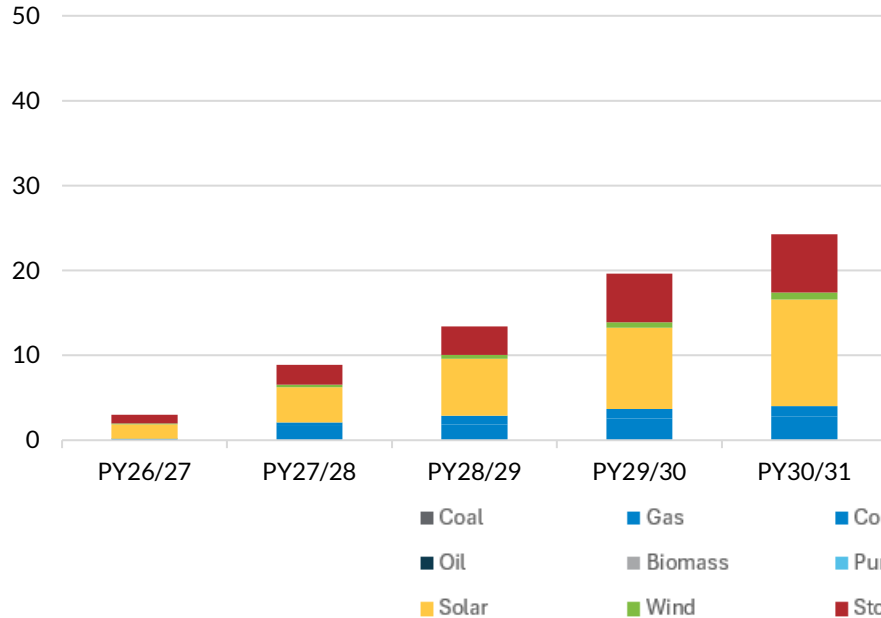
- Capacity accreditation values and Planning Reserve Margin projections based on current practices
- Regional Directional Transfer (RDT) limit of 1900 MW is reflected in this chart

OMS-MISO Survey projections of new resource accreditation value

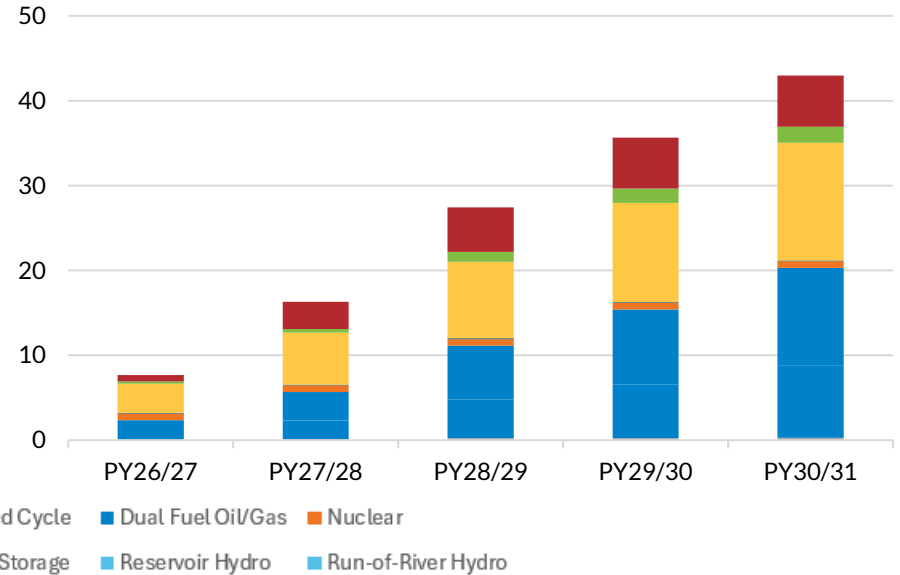
-Status Quo SAC calculations

Projections of New Resource Fuel Mix – Summer

Historical + Replacement Projection
New Resource Capacity (GW Summer SAC)



Emerging + Replacement Projection
New Resource Capacity (GW Summer SAC)

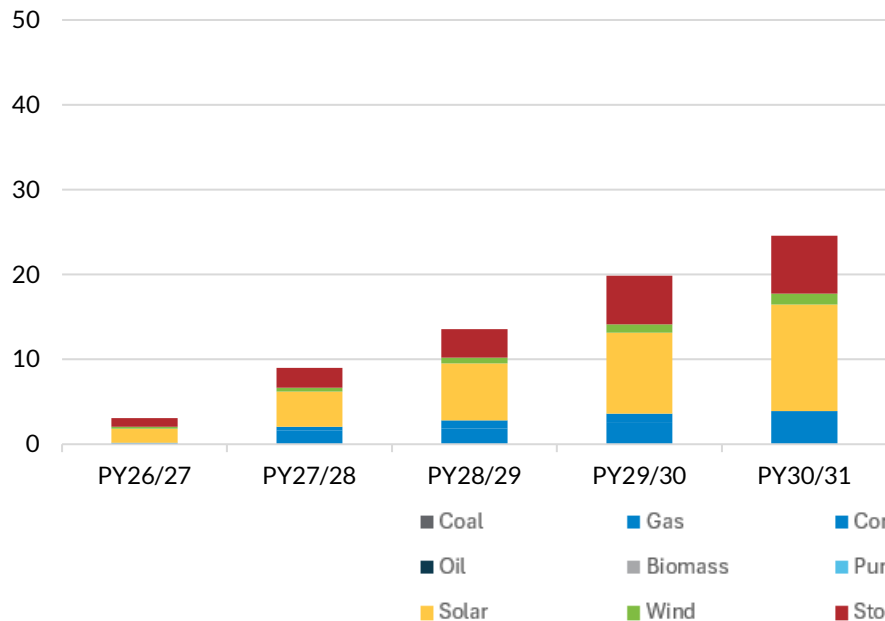


OMS-MISO Survey projections of new resource accreditation value

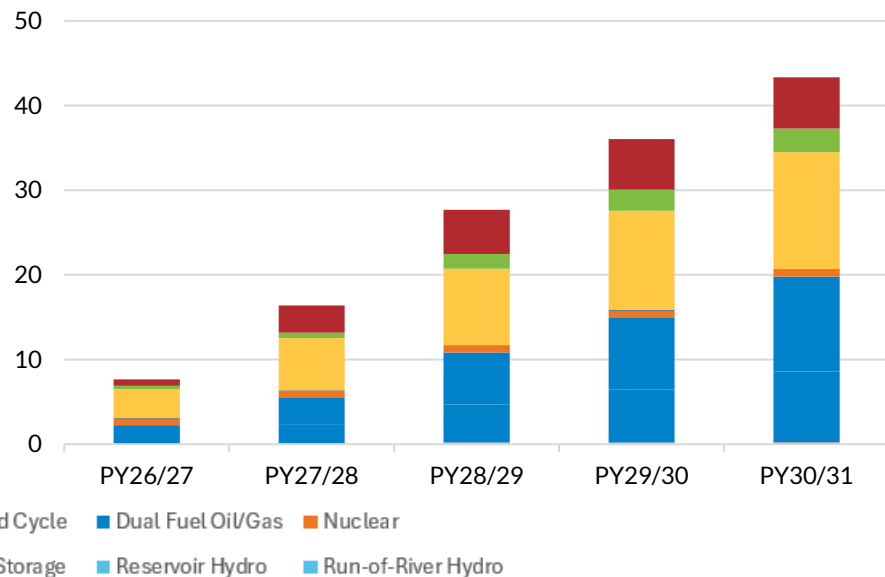
-Status Quo SAC calculations

Projections of New Resource Fuel Mix – Fall

Historical + Replacement Projection*
New Resource Capacity (GW Fall SAC)



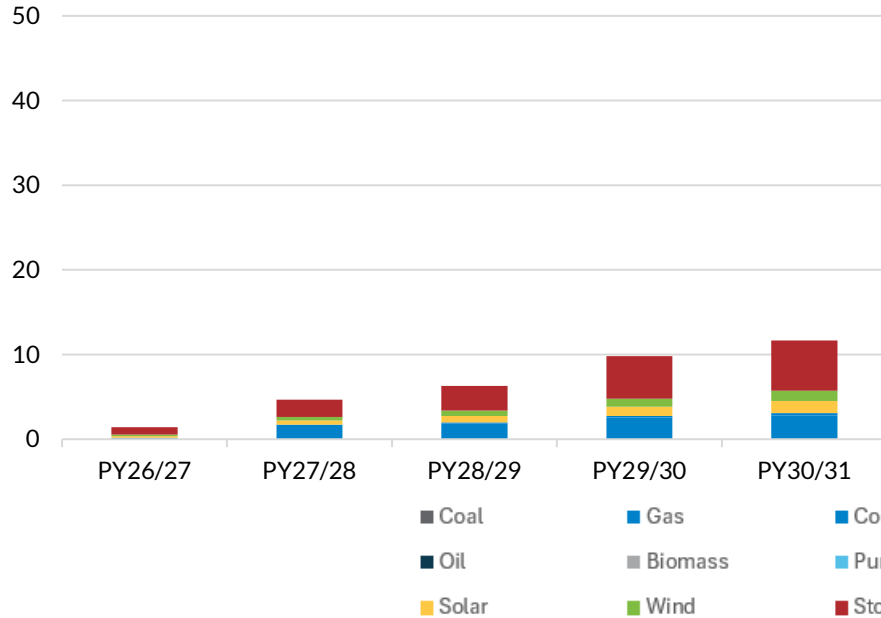
Emerging + Replacement Projection
New Resource Capacity (GW Fall SAC)



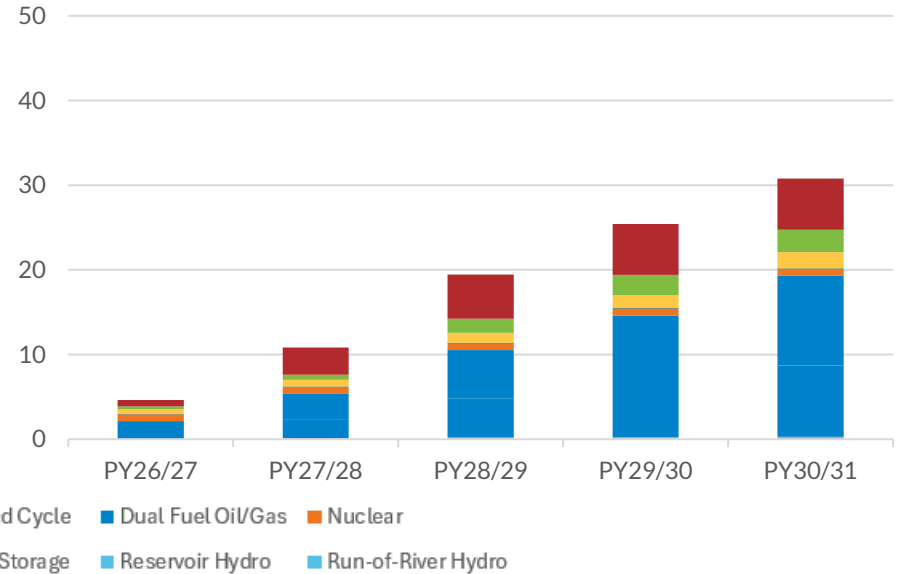
OMS-MISO Survey projections of new resource accreditation value -Status Quo SAC calculations

Projections of New Resource Fuel Mix – Winter

**Historical + Replacement Projection
New Resource Capacity (GW Winter SAC)**



**Emerging + Replacement Projection
New Resource Capacity (GW Winter SAC)**

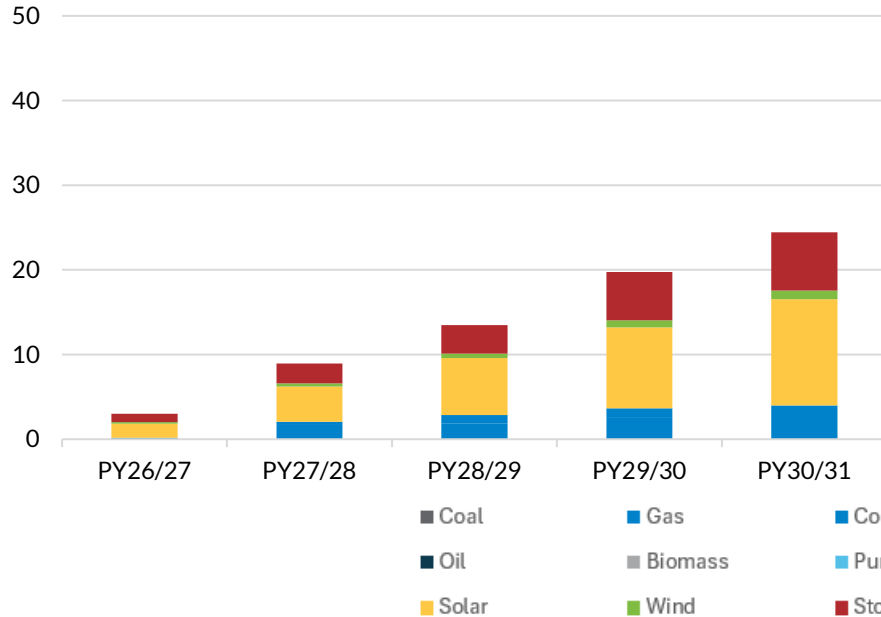


OMS-MISO Survey projections of new resource accreditation value

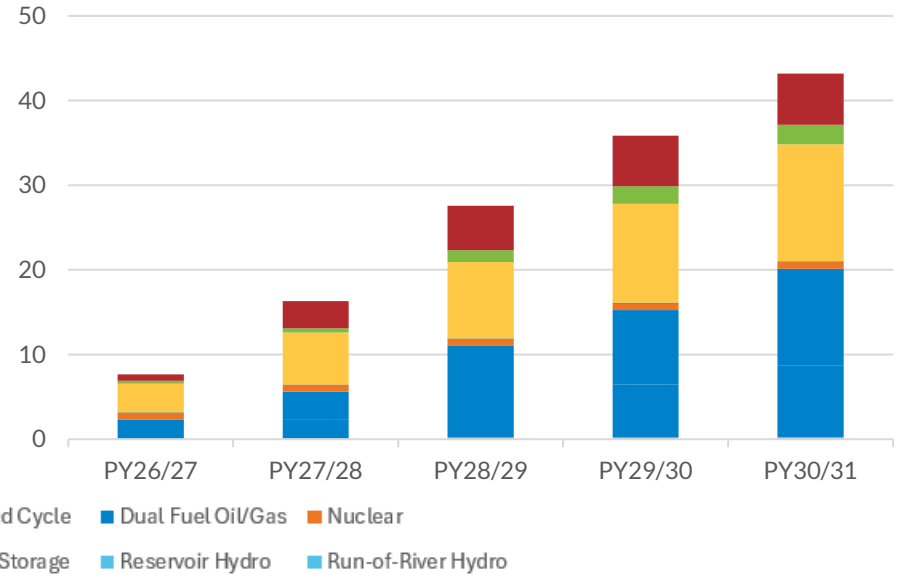
-Status Quo SAC calculations

Projections of New Resource Fuel Mix – Spring

Historical + Replacement Projection
New Resource Capacity (GW Spring SAC)



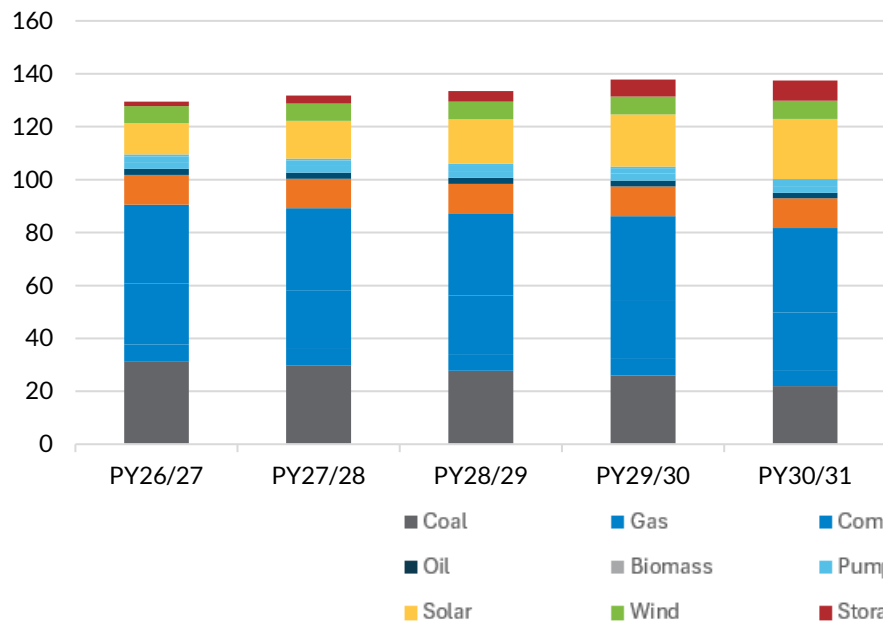
Emerging + Replacement Projection
New Resource Capacity (GW Spring SAC)



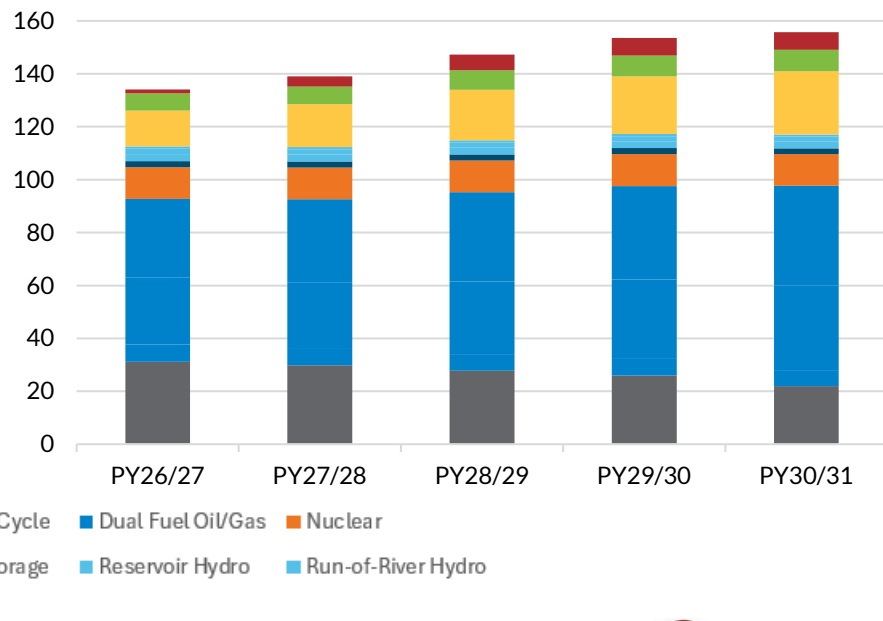
OMS-MISO Survey projections of fleet total resource accreditation value -Status Quo SAC calculations

Combined Projections of Fuel Mix – Summer

Historical + Replacement Projection
Total Capacity (GW Summer SAC)



Emerging + Replacement Projection
Total Capacity (GW Summer SAC)

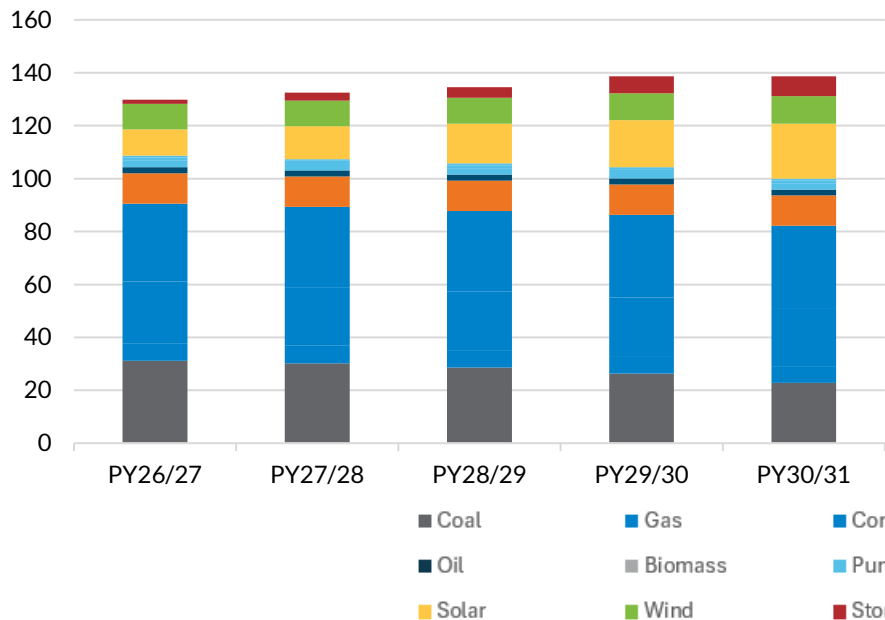


OMS-MISO Survey projections of fleet total resource accreditation value

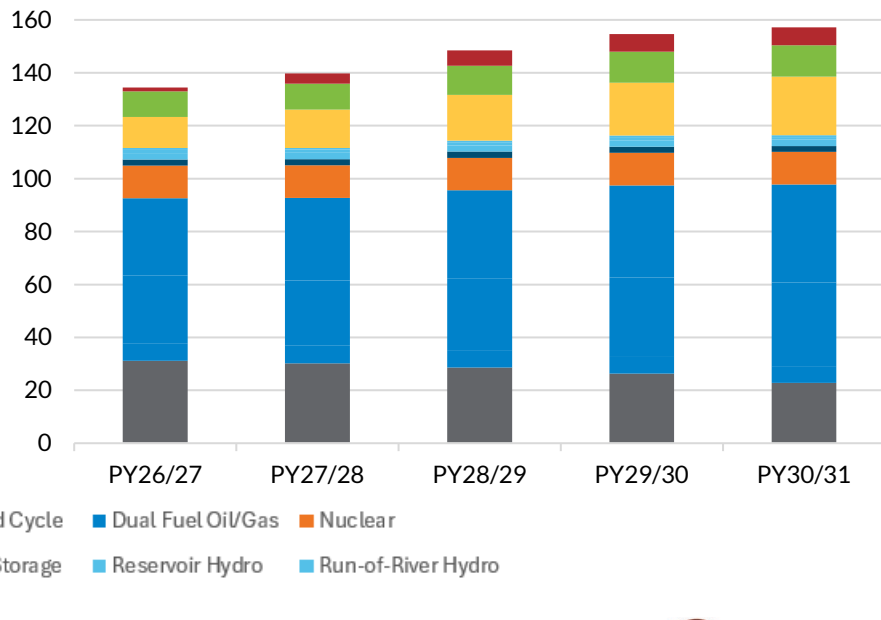
-Status Quo SAC calculations

Combined Projections of Fuel Mix – Fall

Historical + Replacement Projection
Total Capacity (GW Fall SAC)



Emerging + Replacement Projection
Total Capacity (GW Fall SAC)

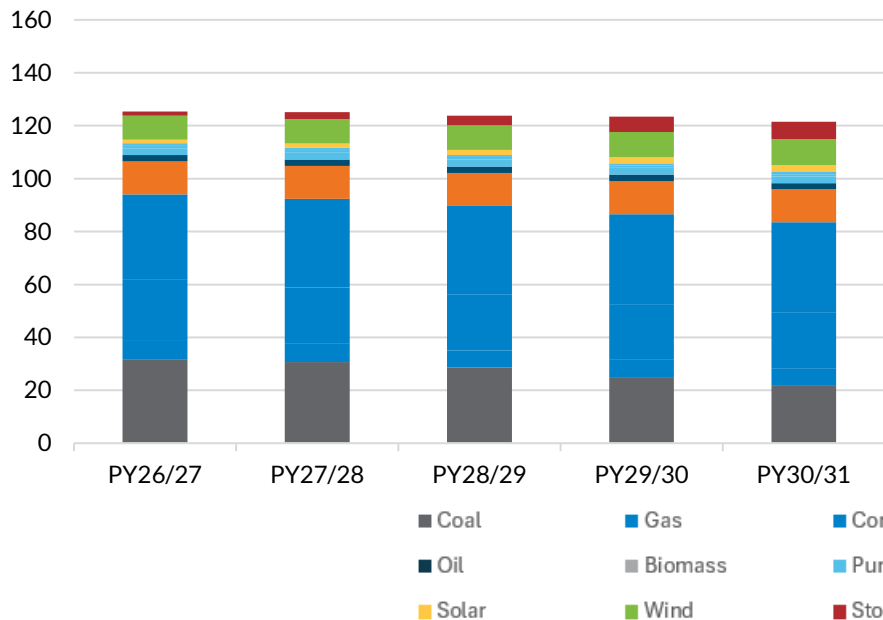


OMS-MISO Survey projections of fleet total resource accreditation value

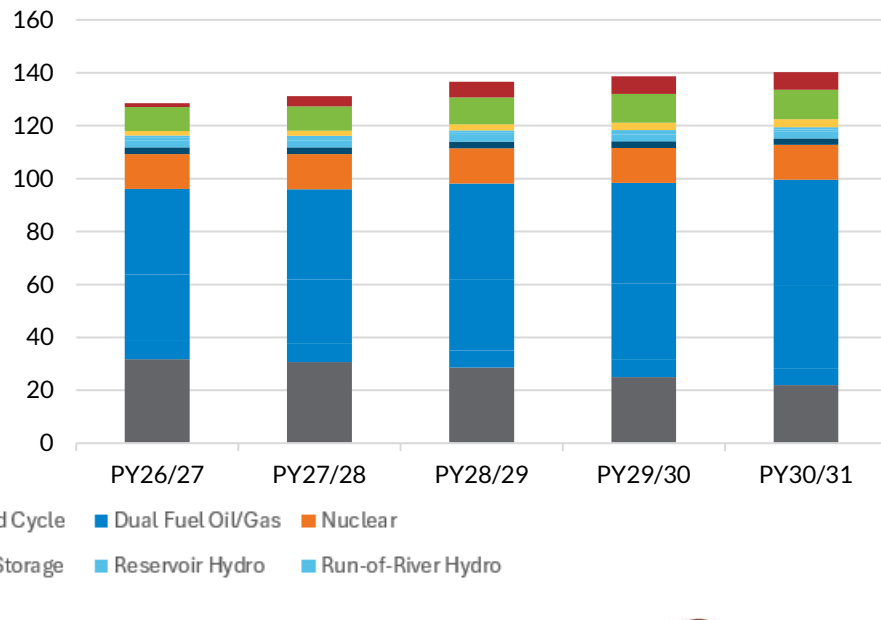
-Status Quo SAC calculations

Combined Projections of Fuel Mix – Winter

Historical + Replacement Projection
Total Capacity (GW Winter SAC)



Emerging + Replacement Projection
Total Capacity (GW Winter SAC)

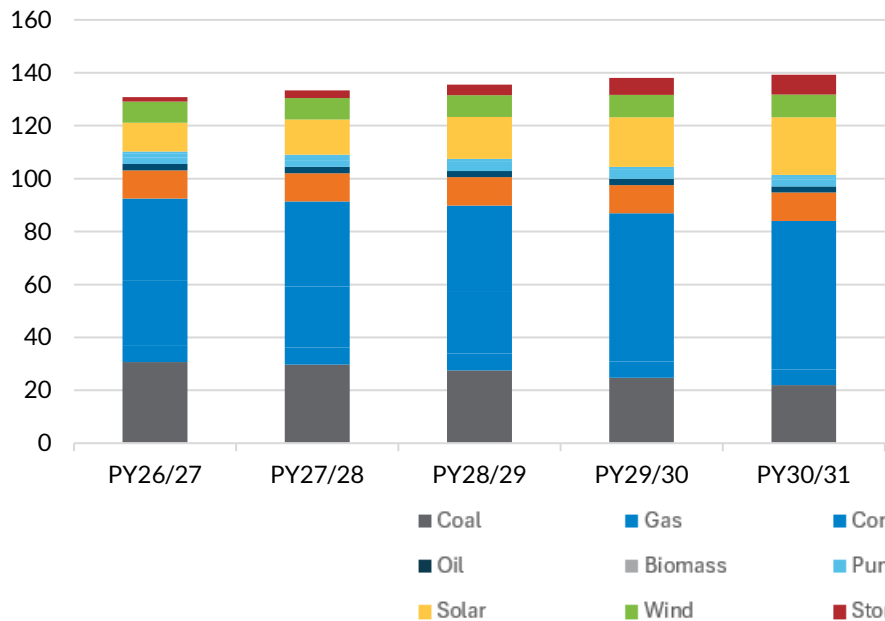


OMS-MISO Survey projections of fleet total resource accreditation value

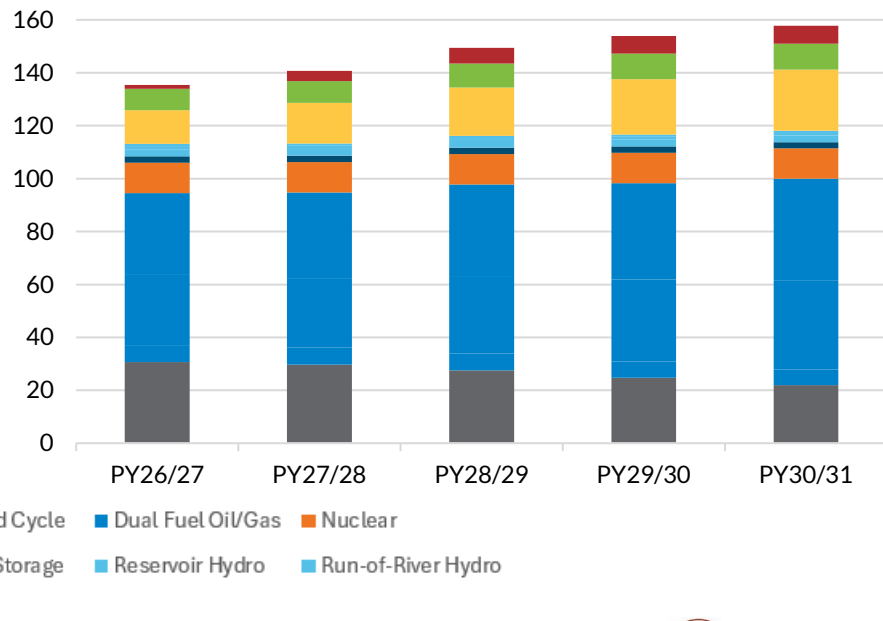
-Status Quo SAC calculations

Combined Projections of Fuel Mix – Spring

**Historical + Replacement Projection
Total Capacity (GW Spring SAC)**



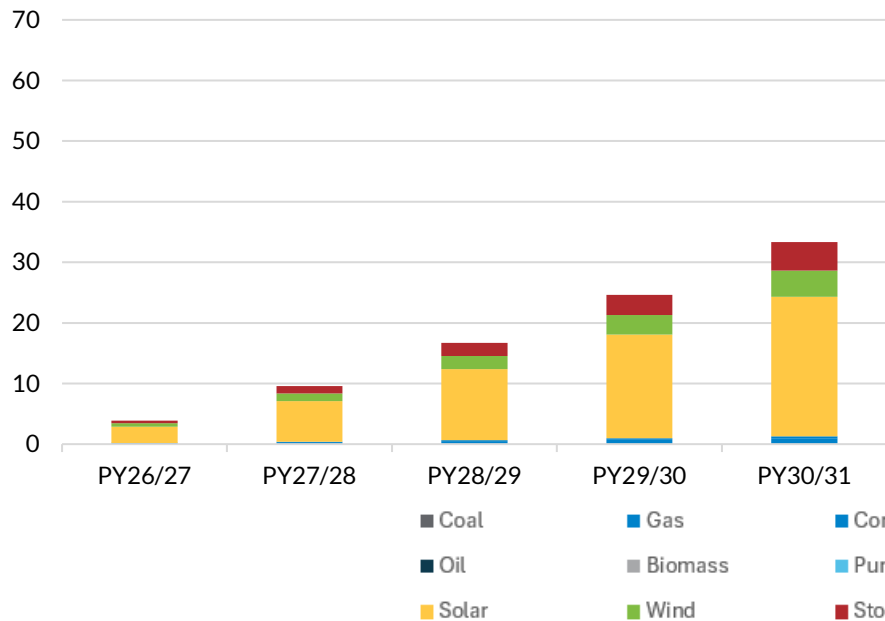
**Emerging + Replacement Projection
Total Capacity (GW Spring SAC)**



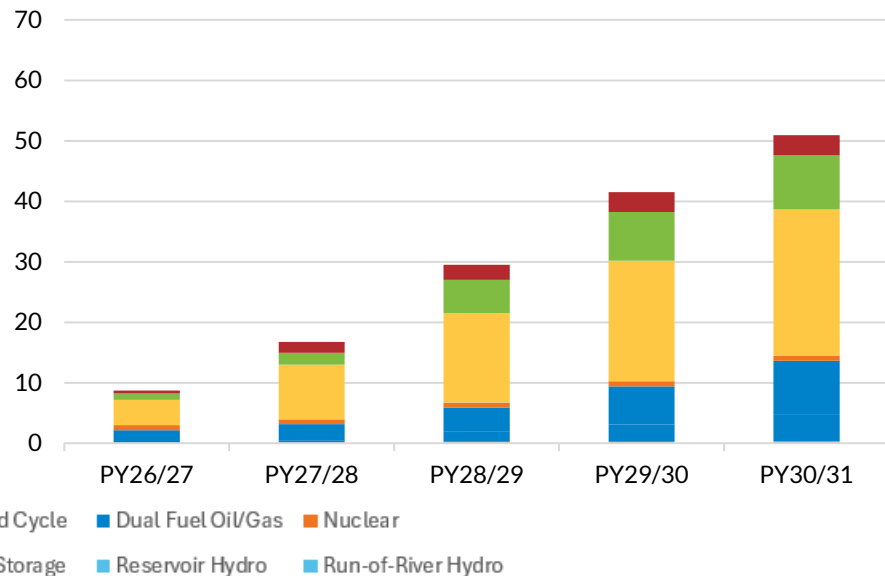
OMS-MISO Survey projections of new resource deliverable nameplate

Combined Projections of Fuel Mix, New Resource Nameplate Only (ICAP)

Historical Projection
New Resource Nameplate (GW)



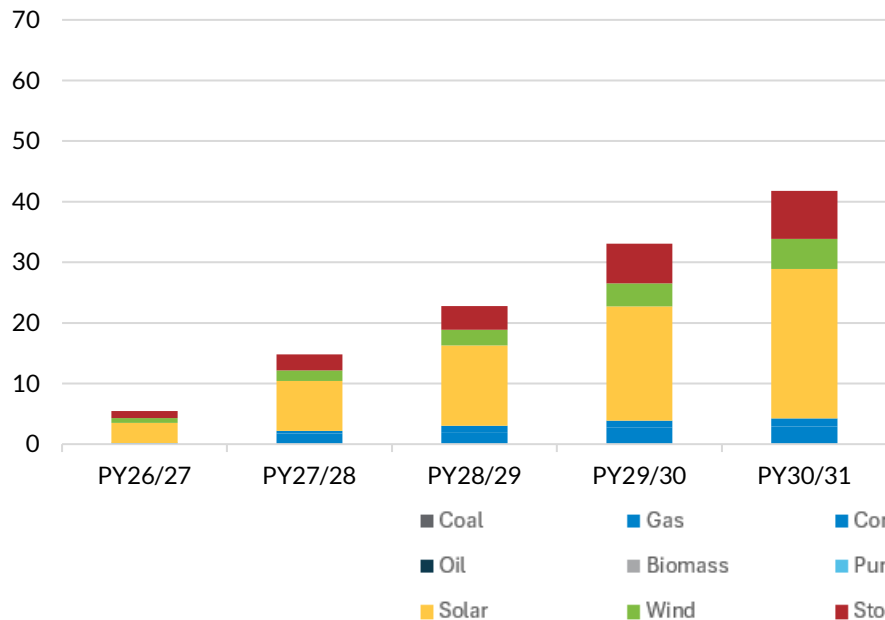
Emerging Projection
New Resource Nameplate (GW)



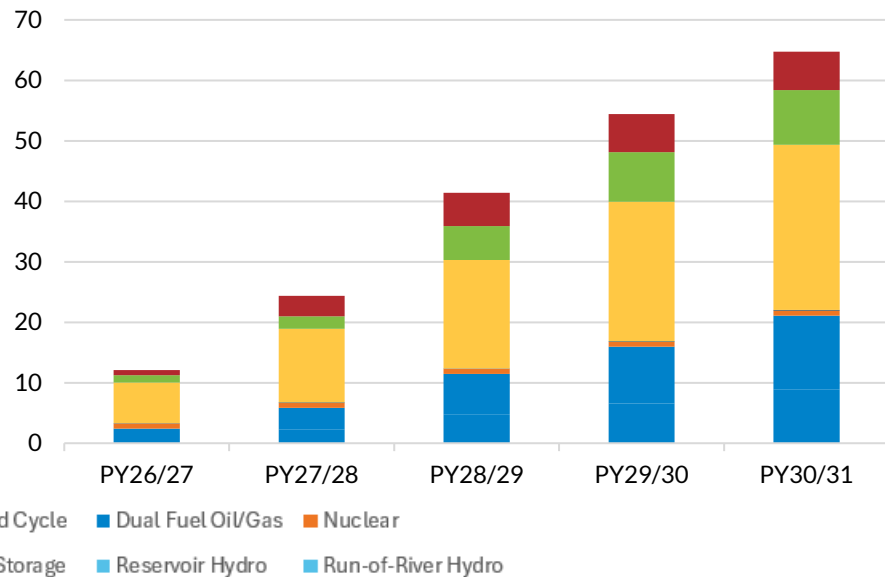
OMS-MISO Survey projections of new resource deliverable nameplate

Combined Projections of Fuel Mix, New Resource Nameplate Only (ICAP)

**Historical + Replacement Projection
New Resource Nameplate (GW)**



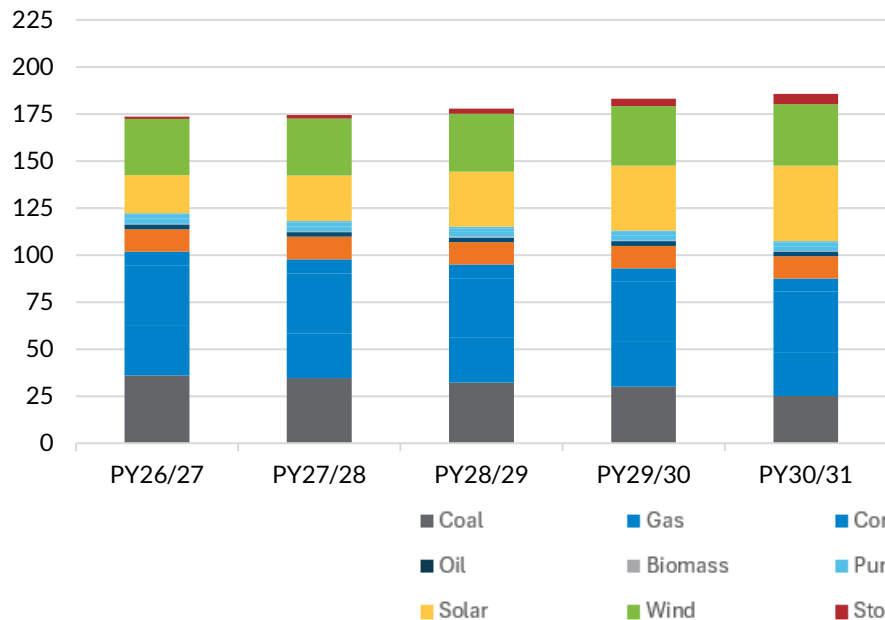
**Emerging + Replacement Projection
New Resource Nameplate (GW)**



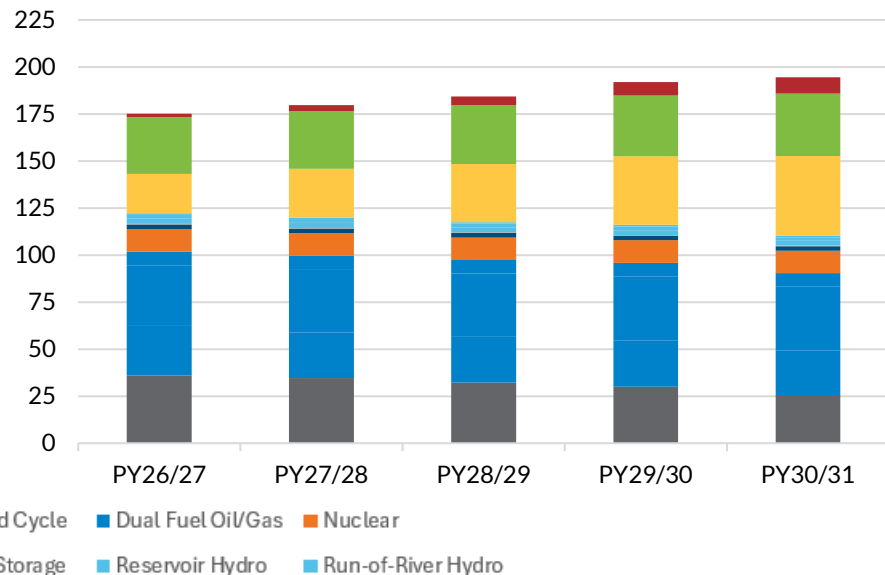
OMS-MISO Survey projections of fleet total deliverable nameplate

Combined Projections of Fuel Mix, Fleet Composition by Nameplate (ICAP)

Historical Projection
Total Nameplate (GW)



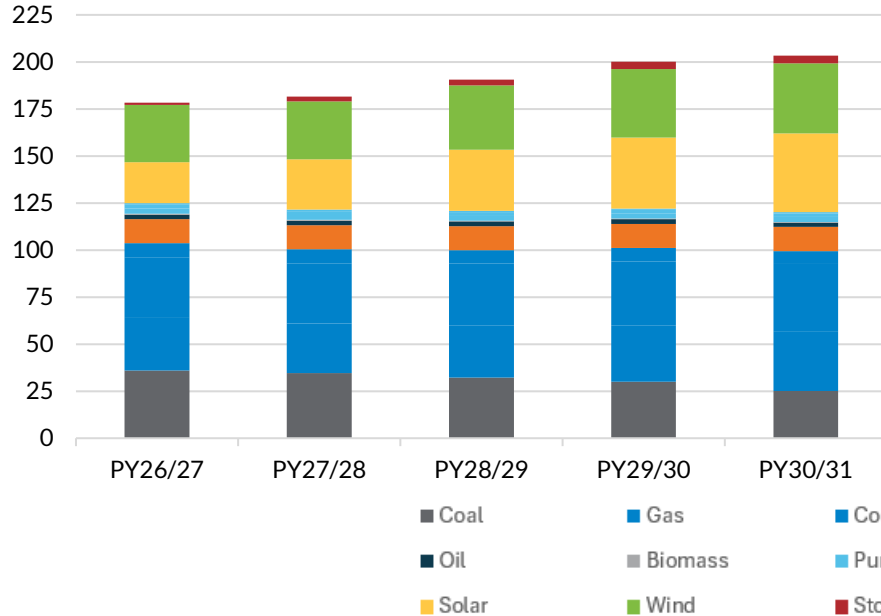
Historical + Replacement Projection
Total Nameplate (GW)



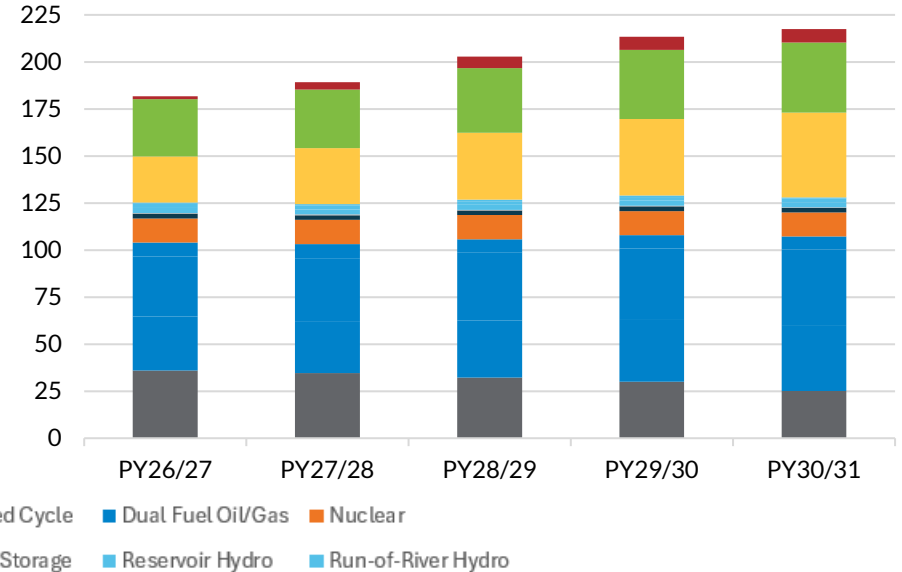
OMS-MISO Survey projections of fleet total deliverable nameplate

Combined Projections of Fuel Mix, Fleet Composition by Nameplate (ICAP)

**Emerging Projection
Total Nameplate (GW)**



**Emerging + Replacement Projection
Total Nameplate (GW)**





U.S. DEPARTMENT
of ENERGY



Resource Adequacy Report

Evaluating the Reliability and Security of the United States Electric Grid

July 2025

Acknowledgments

This report and associated analysis were prepared for DOE purposes to evaluate both the current state of resource adequacy as well as future pressures resulting from the combination of announced retirements and large load growth.

It was developed in collaboration with and with assistance from the Pacific Northwest National Laboratory (PNNL) and National Renewable Energy Laboratory (NREL). We thank the North American Electric Reliability Corporation (NERC) for providing data used in this study, the Telos Corporation for their assistance in interpreting this data, and the U.S. Energy Information Administration (EIA) for their dissemination of historical datasets. In addition, thank you to NREL for providing synthetic weather data created by Evolved Energy Research for the Regional Energy Deployment System (ReEDS) model.

DOE acknowledges that the resource adequacy analysis that was performed in support of this study could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level. The DOE study team built the methodology and analysis upon the best data that was available. However, entities responsible for the maintenance and operation of the grid have access to a range of data and insights that could further enhance the robustness of reliability decisions, including resource adequacy, operational reliability, and resilience.

Historically, the nation's power system planners would have shared electric reliability information with DOE through mechanisms such as EIA-411, which has been discontinued. Thus, one of the key takeaways from this study process is the underscored "call to action" for strengthened regional engagement, collaboration, and robust data exchange which are critical to addressing the urgency of reliability and security concerns that underpin our collective economic and national security.

Table of Contents

Acknowledgments	i
Background to this Report.....	vi
Executive Summary	1
1 Modeling Methodology	10
1.1 Modeling Resource Adequacy.....	13
1.2 Planning Years and Weather Years	15
1.3 Load Modeling.....	15
1.4 Transfer Capabilities and Import Export Modeling	18
1.5 Perfect Capacity Additions	19
2 Regional Analysis.....	20
2.1 MISO.....	20
2.2 ISO-NE.....	23
2.3 NYISO.....	25
2.4 PJM.....	27
2.5 SERC.....	30
2.6 SPP.....	Error!
Bookmark not defined.	
2.7 CAISO+	35
2.8 West Non-CAISO.....	37
2.9 ERCOT.....	40
Appendix A - Generation Calibration and Forecast	A-1
Appendix B - Representing Canadian Transfer Limits.....	B-1
References	C-1
EO 14262.....	C-3

List of Figures

Figure 1. Mean Annual LOLH by Region (2030) – Plant Closures	6
Figure 2. Mean Annual LOLH by Region (2030) – No Plant Closures	6
Figure 3. Mean Annual NUSE by Region (2030) -Plant Closures	8
Figure 4. Tuned Perfect Capacity (MW) By Region	9
Figure 5. TPRs used in NERC ITCS	10
Figure 6. Simplified Overview of Model	14
Figure 7. 2024 to 2030 Projected Data Center Load Additions	16
Figure 8. New Data Center Build (% Split by ISO/RTO) (2030 Estimated).....	17
Figure 9. Mean Peak Load by RTO (Current Case vs 2030 Case)	18
Figure 10. MISO Max Daily Load in the Current System versus 2030	21
Figure 11. MISO Generation Capacity by Technology and Scenario	21
Figure 12. ISO-NE Max Daily Load in the Current System versus 2030	23
Figure 13. ISO-NE Generation Capacity by Technology and Scenario	24
Figure 14. NYISO Max Daily Load in the Current System versus 2030	25
Figure 15. NYISO Generation Capacity by Technology and Scenario	26
Figure 16. PJM Max Daily Load in the Current System versus 2030	28
Figure 17. PJM Generation Capacity by Technology and Scenario	28
Figure 18. SERC Max Daily Load in the Current System versus 2030.....	30
Figure 19. SERC Generation Capacity by Technology and Scenario	31
Figure 20. SPP Max Daily Load in the Current System versus 2030	33
Figure 21. SPP Generation Capacity by Technology and Scenario	33
Figure 22. CAISO+ Max Daily Load in the Current System versus 2030	35
Figure 23. CAISO+ Generation Capacity by Technology and Scenario	36
Figure 24. West Non-CAISO Max Daily Load in the Current System versus 2030	38
Figure 25. West Non-CAISO Generation Capacity by Technology and Scenario	38
Figure 26. ERCOT Max Daily Load in the Current System versus 2030	41
Figure 27. ERCOT Generation Capacity by Technology and Scenario.....	41

List of Tables

Table 1. Summary Metrics Across Cases	7
Table 2. Summary of MISO Reliability Metrics	20
Table 3. Nameplate Capacity by MISO Subregion and Technology (MW).....	22
Table 4. Summary of ISO-NE Reliability Metrics	23
Table 5. Nameplate Capacity by ISO-NE Subregion and Technology (MW).....	24
Table 6. Summary of NYISO Reliability Metrics	25
Table 7. Nameplate Capacity by NYISO Subregion and Technology (MW).....	26
Table 8. Summary of PJM Reliability Metrics	27
Table 9. Nameplate Capacity by PJM Subregion and Technology (MW).....	29
Table 10. Summary of SERC Reliability Metrics	30
Table 11. Nameplate Capacity by SERC Subregion and Technology (MW).....	31
Table 12. Summary of SPP Reliability Metrics	32
Table 13. Nameplate Capacity by SPP Subregion and Technology (MW).....	34
Table 14. Summary of CAISO+ Reliability Metrics	35
Table 15. Nameplate Capacity by CAISO+ Subregion and Technology (MW).....	36
Table 16. Summary of West Non-CAISO Reliability Metrics	37
Table 17. Nameplate Capacity by West Non-CAISO Subregion and Technology (MW).....	39
Table 18. Summary of ERCOT Reliability Metrics.....	40
Table 19. Nameplate Capacity for ERCOT and by Technology (MW)	42

Additional figures and tables in appendices

List of Acronyms

AI	Artificial Intelligence
CAISO	California Independent System Operator
DOE	U.S. Department of Energy
EIA	Energy Information Administration
EO	Executive Order
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
EUE	Expected Unserved Energy
FERC	Federal Energy Regulatory Commission
GADS	Generating Availability Data System
ISO	Independent System Operator
ISO-NE	ISO New England Inc.
ITCS	Interregional Transfer Capability Study
LBL	Lawrence Berkeley National Laboratory
LOLE	Loss of Load Expectation
LOLH	Loss of Load Hours
LTRA	Long-Term Reliability Assessment
MISO	Midcontinent Independent System Operator
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
PJM	PJM Interconnection, LLC
PNNL	Pacific Northwest National Laboratory
ReEDS	Regional Energy Deployment System
RTO	Regional Transmission Organization
SERC	SERC Reliability Corporation
TPR	Transmission Planning Region
USE	Unserved Energy

Background to this Report

On April 8, 2025, President Trump issued Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid." EO 14262 builds on EO 14156, "Declaring a National Emergency (Jan. 20, 2025)," which declared that the previous administration had driven the Nation into a national energy emergency where a precariously inadequate and intermittent energy supply and increasingly unreliable grid require swift action. The United States' ability to remain at the forefront of technological innovation depends on a reliable supply of energy and the integrity of our Nation's electrical grid.

EO 14262 mandates the development of a uniform methodology for analyzing current and anticipated reserve margins across regions of the bulk power system regulated by the Federal Energy Regulatory Commission (FERC). Among other things, EO 14262 requires that such methodology accredit generation resources based on the historical performance of each generation resource type. This report serves as DOE's response to Section 3(b) of EO 14262 by delivering the required uniform methodology to identify at-risk region(s) and guide reliability interventions. The methodology described herein and any analysis it produces will be assessed on a regular basis to ensure its usefulness for effective action among industry and government decision-makers across the United States.

Executive Summary

Our Nation possesses abundant energy resources and capabilities such as oil and gas, coal, and nuclear. The current administration has made great strides—such as deregulation, permitting reform, and other measures—to enable addition of more energy infrastructure crucial to the utilization of these resources. However, even with these foundational strengths, the accelerated retirement of existing generation capacity and the insufficient pace of firm, dispatchable generation additions (partly due to a recent focus on intermittent rather than dispatchable sources of energy) undermine this energy outlook.

Absent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation. A failure to power the data centers needed to win the AI arms race or to build the grid infrastructure that ensures our energy independence could result in adversary nations shaping digital norms and controlling digital infrastructure, thereby jeopardizing U.S. economic and national security.

Despite current advancements in the U.S. energy mix, this analysis underscores the urgent necessity of robust and rapid reforms. Such reforms are crucial to powering enough data centers while safeguarding grid reliability and a low cost of living for all Americans.

Key Takeaways

- **Status Quo is Unsustainable.** The status quo of more generation retirements and less dependable replacement generation is neither consistent with winning the AI race and ensuring affordable energy for all Americans, nor with continued grid reliability (ensuring “resource adequacy”). Absent intervention, it is impossible for the nation's bulk power system to meet the AI growth requirements while maintaining a reliable power grid and keeping energy costs low for our citizens.
- **Grid Growth Must Match Pace of AI Innovation.** The magnitude and speed of projected load growth cannot be met with existing approaches to load addition and grid management. The situation necessitates a radical change to unleash the transformative potential of innovation.
- **Retirements Plus Load Growth Increase Risk of Power Outages by 100x in 2030.** The retirement of firm power capacity is exacerbating the resource adequacy problem. 104 GW of firm capacity are set for retirement by 2030. This capacity is not being replaced on a one-to-one basis and losing this generation could lead to significant outages when weather conditions do not accommodate wind and solar generation. In the “plant closures” scenario of this analysis, annual loss of load hours (LOLH) increased by a factor of a hundred.
- **Planned Supply Falls Short, Reliability is at Risk.** The 104 GW of retirements are projected to be replaced by 209 GW of new generation by 2030; however, only 22 GW would come from firm baseload generation sources. Even assuming no retirements, the model found increased risk of outages in 2030 by a factor of 34.

- **Old Tools Won't Solve New Problems.** Antiquated approaches to evaluating resource adequacy do not sufficiently account for the realities of planning and operating modern power grids. At a minimum, modern methods of evaluating resource adequacy need to incorporate frequency, magnitude, and duration of power outages; move beyond exclusively analyzing peak load time periods; and develop integrated models to enable proper analysis of increasing reliance on neighboring grids.

This report clearly demonstrates the need for rapid and robust reform to address resource adequacy issues across the Nation. Inadequate resource adequacy will hinder the development of new manufacturing in America, slow the re-industrialization of the U.S. economy, drive up the cost of living for all Americans, and eliminate the potential to sustain enough data centers to win the AI arms race.

Developing a Uniform Methodology

DOE's resource adequacy methodology assesses the U.S. electric grid's ability to meet future demand through 2030. It provides a forward-looking snapshot of resource adequacy that is tied to electricity supply and new load growth, systematically exploring a range of dimensions that can be compared across regions. As detailed in the methodology section of this report, the model is derived from the North American Electric Reliability Corporation (NERC) Interregional Transfer Capability Study (ITCS) which leverages time-correlated generation and outages based on actual historic data.¹ A deterministic approach² simulates system stress in all hours of the year and incorporates varied grid conditions and operating scenarios based on historical events:

- **Demand for Electricity – Assumed Load Growth:** The methodology accounts for the significant impact of data centers, particularly those supporting AI workloads, on electricity demand. Various organizations' projections for incremental data center electricity use by 2030 range widely (35 GW to 108 GW). DOE adopted a national midpoint assumption of 50 GW by 2030, aligning with central projections from Electric Power Research Institute (EPRI)³ and Lawrence Berkeley National Laboratory (LBNL).⁴ This 50 GW was allocated regionally using state-level growth ratios from S&P's forecast,⁵ reflecting infrastructure characteristics, siting trends, and market activity; and, mapped to NERC Transmission Planning Regions (TPRs).

1. This model differs from traditional peak hour reliability assessments in that it explicitly simulates grid performance hour-by-hour across multiple weather years with finer geographic detail and optimized inter-regional transfers, and explores various retirement and build-out scenarios. Furthermore, the DOE approach integrates weather-synchronized outage data.

2. Deterministic approaches evaluate resource adequacy using relatively stable or fixed assumptions about the representation of the power system. Probabilistic approaches incorporate data and advanced modeling techniques to represent uncertainty that require more computing power. Deterministic was chosen for this analysis for transparency and to model detailed historic system conditions.

3. EPRI, "Powering Intelligence: Analyzing Artificial Intelligence and Data Center Energy Consumption," March 2024, <https://www.epri.com/research/products/3002028905>.

4. Shehabi, A., et al., "2024 United States Data Center Energy Usage Report," <https://escholarship.org/uc/item/32d6m0d1>.

5. S&P Global – Market Intelligence, "US Datacenters and Energy Report," 2024.

An additional 51 GW of non-data center load was modeled using NERC data, historical loads (2019-2023), and simulated weather years (2007-2013), adjusted by the Energy Information Administration's (EIA) 2022 energy forecast, with interpolation between 2024 and 2033 to estimate 2030 demand.

- **Supply of Electricity – Assumed Generation Retirements and Additions:** Between the current system and the projected 2030 system, the model considers three scenarios for generator retirements and additions. These scenarios were selected to describe the metrics of interest and how they change during certain assumptions of generation growth and retirements.

The resource adequacy standard (or criterion) is the measure that defines the desired level of adequacy needed for a given system. Conceptually, a resource adequacy criterion has two components—metrics and target levels—that determine whether a system is considered adequate. Comprehensive resource adequacy metrics⁶ are incorporated in this analysis to capture the magnitude and duration of system stress events:

- **Magnitude of Outages – Normalized Unserved Energy (NUSE):** Measures the amount of unmet electrical energy demand because of insufficient generation or transmission, typically measured in megawatt hours (MWh).

While USE describes the absolute amount of energy not delivered, it is less useful when comparing systems of different size or across different periods. Normalizing, by dividing by total load over a whole period (for example, a year) allows comparison of these metrics across different system sizes, demand levels, and periods of analysis. For example, 100 MWh of USE in a small, isolated microgrid can be more impactful than 100 MWh of USE in a larger regional grid that serves millions of people. USE is normalized by dividing by total load:

$$\frac{100 \text{ MWh (of unserved energy)}}{10,000,000 \text{ MWh (of total energy delivered in a year)}} \times 100 = 0.001 \text{ percent}$$

Although the use of NUSE is not standardized in the U.S. today,⁷ several system operators domestically and across the world have begun using NUSE as a useful metric.

- **Duration of Outages – Loss of Load Hours (LOLH):** Measures the expected duration of power outages when a system's load exceeds its available generation capacity. At the core, LOLH helps assess how frequently and for how long the power system is likely to experience insufficient supply, providing a picture of reliability in terms of time. LOLH is calculated as both a total and average value per year, in addition to the maximum percentage of load lost in any given hour per year.

6. In the interest of technical accuracy, and separate from their contextualization in the main text, NUSE is more precisely a measure of volume that is expressed as a percentage. Similarly, 2.4 hours of LOLH represents the cumulative sum of distinct periods of load loss, not a singular, continuous duration.

7. There is no common planning criterion for this metric in North America. NERC's Long-Term Reliability Assessment employs a normalized expected unserved energy (NEUE) metric to define target risk levels for each region. Grid operators, such as ISO-NE, have also considered NUSE in energy adequacy studies. For example, see ISO-NE, "Regional Energy Shortfall Threshold (REST): ISO's Current Thinking Regarding Tail Selection," April 2025, https://www.iso-ne.com/static-assets/documents/100022/a09_rest_april_2025.pdf.

Reliability Standard

DOE's methodology recognizes that the traditional 1-in-10 loss of load expectation (LOLE) criterion is insufficient for a complete assessment of resource adequacy and risk profile. This antiquated criterion is not calculated uniformly and fails to adequately account for crucial factors such as the duration and magnitude of potential outages.⁸ To provide a comprehensive understanding of system reliability and, specifically, to complement current resource adequacy standards while informing the creation of new criteria, the methodology uses the following reliability standard:

- **Duration of Outages:** No more than 2.4 hours of lost load in an individual year.⁹ This translates into one day of lost load in ten years to meet the 1-in-10 criteria.
- **Magnitude of Outages:** No more than an NUSE of 0.002%.¹⁰ This means that the total amount of energy that cannot be supplied to customers is 0.002% of the total energy demanded in a given year.

Achieving Reliability Standard

- **Perfect Capacity Surplus/Deficit:** Defined as the amount of generation capacity (in MW) a region would need to achieve specified threshold conditions. Based on these thresholds, this standard helps answer the hypothetical question of how much more (or less) power plant capacity is needed for a power system to be considered "perfectly reliable" according to pre-defined standards. This methodology employs this perfect capacity metric to identify the amount of capacity needed to remedy potential shortfalls (or excesses) in generation.

Key Results Summary

This analysis developed three separate cases for 2030. The "**Plant Closures**" case assumes all announced retirements occur plus mature generation additions based on NERC's Tier 1 resources category,¹¹ which encompasses completed and under-construction power generation projects, as well as those with firm-signed and approved interconnection service or power purchase agreements. The "**No Plant Closures**" case assumes no retirements plus mature additions. A "**Required Build**" case further compares the impacts of retirements on perfect capacity additions needed to return 2030 to the current system level of reliability.

8. While 1-in-10 analyses have evolved, industry experts have raised concerns about its effectiveness to address future system risks. Concerns include energy constraints that arise from intermittent resources, increasing battery storage, limited fuel supplies, and the shifting away of peak load periods from times of supply shortfalls.

9. The "1-in-10 year" reliability standard for electricity grids means that, on average, there should be no more than one day (24 hours) of lost load over a ten-year period. This translates to a maximum of 2.4 hours of lost load per year.

10. This analysis targets NUSE below 0.002% for each region because this is the target NERC uses to represent high risk in resource adequacy analyses. Estimates used in industry and analyzed recently range from 0.0001% to 0.003%.

11. Mature generation additions are based on NERC's 2024 LTRA Tier 1 resources, which assume that only projects considered very mature in the development pipeline will be built. For example, Tier 1 additions are those with signed interconnection agreements or power purchase agreements, or included in an integrated resource plan, indicating a high degree of certainty in their addition to the grid. Full details of the retirement and addition assumptions can be found in the methodology section of this report.

DOE ran simulations using 12 different years of historical weather. Every hour was based on actual data for wind, solar, load, and thermal availability to stress test the grid under a range of realistic weather conditions. The benefit of this approach is that it allows for transparent review of how actual conditions manifest themselves in capacity shortfalls. For all scenarios, LOLH and NUSE are calculated and used to compare how they change based on generation growth, retirements, and potential weather conditions.

- **Current System:** Supply of power (generation) and demand for power (load) consistent with 2024 NERC Long-Term Reliability Assessment (LTRA), including 2023 actual generation plus Tier 1 additions for 2024.
- **Plant Closures:** This case assumes 104 GW of announced retirements based on NERC estimates including approximately 71 GW of coal and 25 GW of natural gas, which closely align with retirement numbers in EIA's 2025 Annual Energy Outlook. In addition, this case assumes 100% of 2024 NERC LTRA Tier 1 additions totaling 209 GW are constructed by 2030. This includes 20 GW of new natural gas, 31 GW of additional 4-hour batteries, 124 GW of new solar and 32 GW of incremental wind. Details of the breakdown can be found in Appendix A.
- **No Plant Closures:** This case adds all the Tier 1 NERC additions but assumes no retirements.
- **Required Build:** To understand how much capacity may need to be added to reach reliability targets, the analysis adds hypothetical perfect capacity (which is idealized capacity that has no outages or profile) until a NUSE target of 0.002% is realized in each region. This scenario includes the same assumptions about retirements as our Plant Closures scenario described above.

As shown in the figures and tables below, the model shows a significant decline in all reliability metrics between the current system scenario and the 2030 Plant Closures scenario. Most notably, there is a hundredfold increase in annual LOLH from 8.1 hours per year in the current case to 817 hours per year in the 2030 Plant Closures. In the worst weather year assessed, the total lost load hours increase from 50 hours to 1,316 hours.

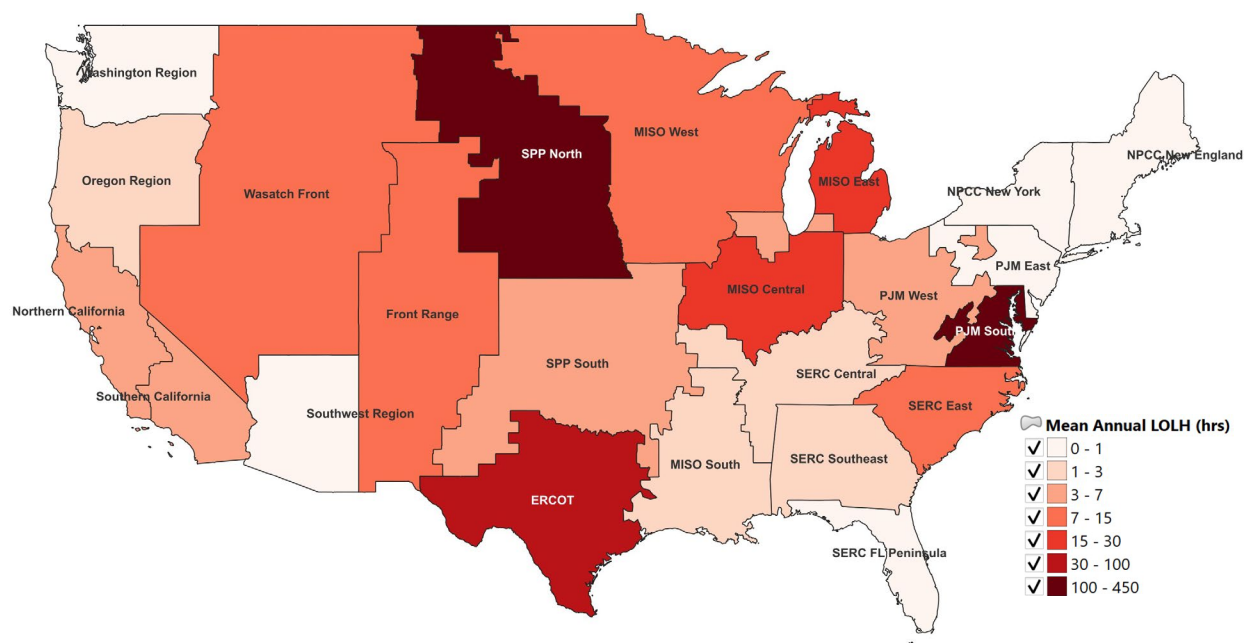


Figure 1. Mean Annual LOLH by Region (2030) – Plant Closures

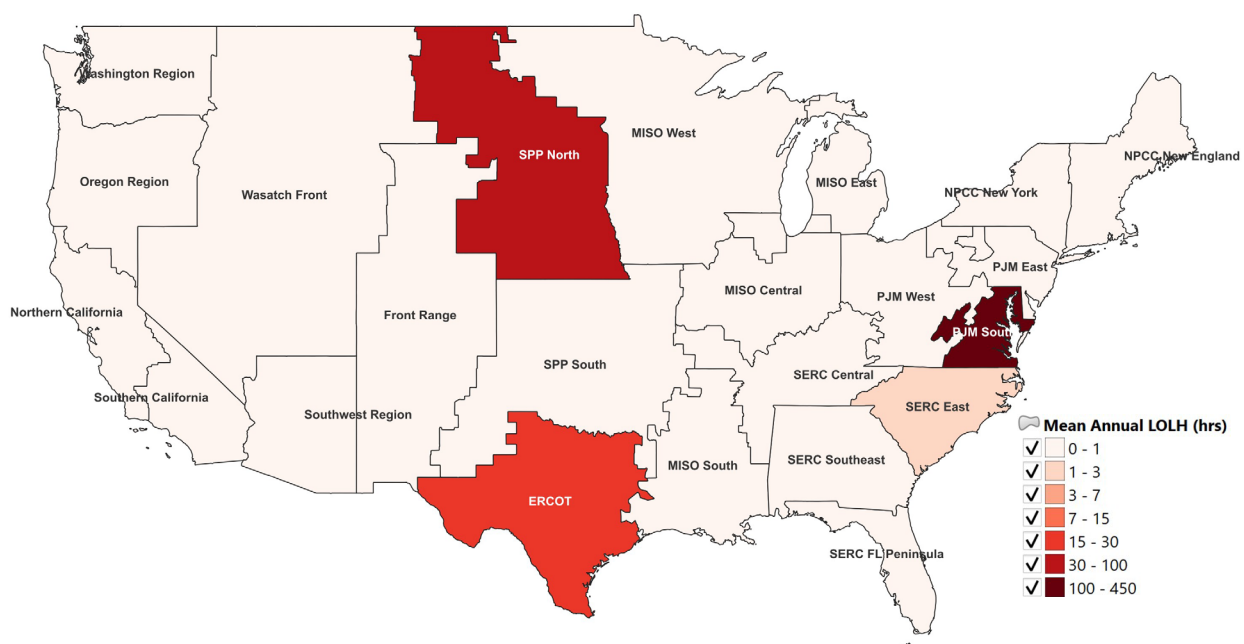


Figure 2. Mean Annual LOLH by Region (2030) – No Plant Closures

Table 1. Summary Metrics Across Cases

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	8.1	817.7	269.9	13.3
Normalized Unserved Energy (%)	0.0005	0.0465	0.0164	0.00048
WORST WEATHER YEAR				
Annual Loss of Load Hours	50	1316	658	53
Normalized Unserved Load (%)	0.0033	0.1119	0.0552	0.002

Current System Analysis

Analysis of the current system shows all regions except ERCOT have less than 2.4 hours of average loss of load per year and less than 0.002% NUSE. This indicates relative reliability for most regions based on the average indicators of risk used in this study. In the current system case, ERCOT would be expected to experience on average 3.8 LOLH annually going forward and a NUSE of 0.0032%. When looking at metrics in the worst weather years, regions meet or exceed additional criteria. All regions experienced less than 20% of lost load in any hour.

However, PJM, ERCOT,¹² and SPP experienced significant loss of load events during 2021 and 2022 winter storms Uri and Elliot which translated into more than 20 hours of lost load. This results in a concentration of lost load within certain years such that some regions exceeded 3-hours-per-year of lost load. It is worth noting that in the case of PJM and SPP, the current system model shortfalls occurred within subregions rather than for the entire ISO footprint.

12. ERCOT has since winterized its generation fleet and did not suffer any outages during Winter Storm Elliot.

2030 Model Results

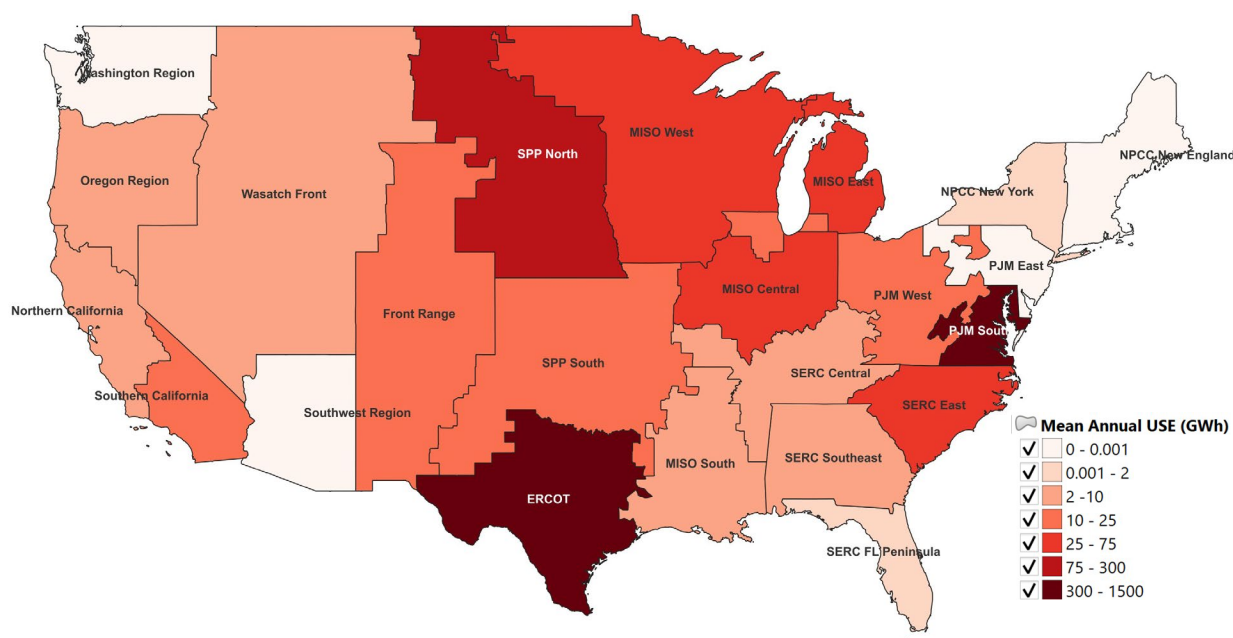


Figure 3. Mean Annual NUSE by Region (2030) -Plant Closures

Key Findings – Plant Closures Case:

- **Systemwide Failures:** All regions except ISO-NE and NYISO failed reliability thresholds. These two regions did not have additional AI/data center (AI/DC) load growth modeled.
- **Loss of Load Hours (LOLH):** Ranged from 7 hours/year in CAISO to 430 hours/year in PJM.
- **Load Shortfall Severity:** Max shortfall reached as high as 43% of hourly load in PJM; 31% in CAISO.
- **Normalized Unserved Energy:** Normalized values ranged from 0.0032% (non-CAISO West) to 0.1473% (PJM), far exceeding thresholds of 0.002%.
- **Extreme Events:** Most regions experienced ≥ 3 hours of unserved load in at least one year. PJM had 1,052 hours in its worst year.
- **Spatial Takeaways:** Subregions in PJM, MISO, and SERC met thresholds—indicating possible benefits from transmission—but SPP and CAISO failed in all subregions.

Key Findings – No Plant Closures Case:

- **Improved System Performance:** Most regions avoided loss of load events. PJM, SPP, and SERC still experienced shortfalls.
- **Regional Failures:**

- o **PJM:** 214 hours/year average, 0.066% normalized unserved energy, 644 hours in worst year, max 36% of load lost.
- o **SPP:** 48 hours/year average, 0.008% normalized unserved energy, max 19% load lost.
- o **ERCOT:** 20 average hours, 0.028% normalized unserved energy, 101 max hours/year, peak shortfall of 27%.
- o **SERC-East:** Generally adequate (avg. 1 hour/year, 0.0003% NUSE), but Elliot storm in 2022 caused 42 hours of shortfall.

The overall takeaway is that avoiding announced retirements improves grid reliability, but shortfalls persist in PJM, SPP, ERCOT, and SERC, particularly in winter.

Required Build

This required build analysis quantifies "hypothetical capacity," defined as power that is 100% reliable and available that is needed to resolve the shortfalls. Known in industry as "perfect capacity," this metric is utilized to avoid the complex decision of selecting specific generation technologies, as that is ultimately an optimization of reliability against cost considerations. Nevertheless, it serves as a valuable indicator, illustrating either the magnitude of a resource gap or the scale of large load that will be unable to interconnect. For the Required Build case, this hypothetical capacity was calculated by adding new generating resources to each region until a target of 0.002% of NUSE is reached.

The table below shows the tuned perfect capacity results. For the current system, this analysis identifies an additional 2.4 MW of capacity to meet the NUSE target for PJM, which experiences shortfalls due to the winter storm Elliot historical weather year. By 2030, without considering any generation retirements, an additional 12.5 GW of generating capacity is needed across PJM, SPP, and SERC to reduce shortfalls.

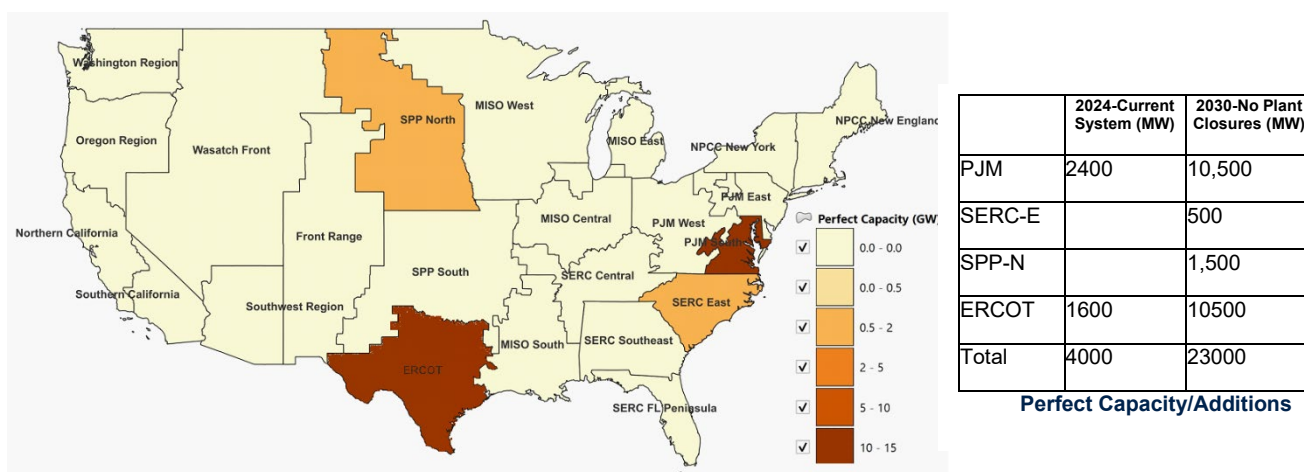


Figure 4. Tuned Perfect Capacity (MW) By Region

1 Modeling Methodology

The methodology uses a zonal PLEXOS¹³ model with hourly time-synchronous datasets for load, generation, and interregional transfer for the 23 U.S. subregions (referred to as TPRs in this study)¹⁴ including ERCOT (see Figure 5 below). While ERCOT operates outside of FERC's general jurisdiction,¹⁵ it provides a valuable case for understanding broader reliability and resource adequacy challenges in the U.S. electric grid, and FPA Section 202(c) allows DOE to issue emergency orders to ERCOT.

We base this analysis on actual weather and power plant outage data from 2007 to 2023 using NERC's ITCS¹⁶ base dataset. DOE specifically decided to start this analysis with the ITCS dataset since it is a complete representation of the interconnected electrical system for the lower 48 and it has been thoroughly reviewed by industry experts in a public and transparent process. DOE has in turn made modifications to the dataset to fit the needs of this study. The contents of this section focus on those modifications which DOE implemented for purposes of this study.

PLEXOS is an industry-trusted simulation tool used for energy optimization, resource adequacy, and production cost modeling. This study leverages PLEXOS' ability to exercise an hourly production cost model to determine the balance between loads, generation, and imports for each region. Modeling was carried out using a deterministic approach that evaluates whether a power system has sufficient resources to meet projected demand under a pre-defined set of conditions which correspond to the past few years of real-world events. The model ultimately determines the amount of unmet load if generation resources and imports are not sufficient for meeting the load in each discrete time period.

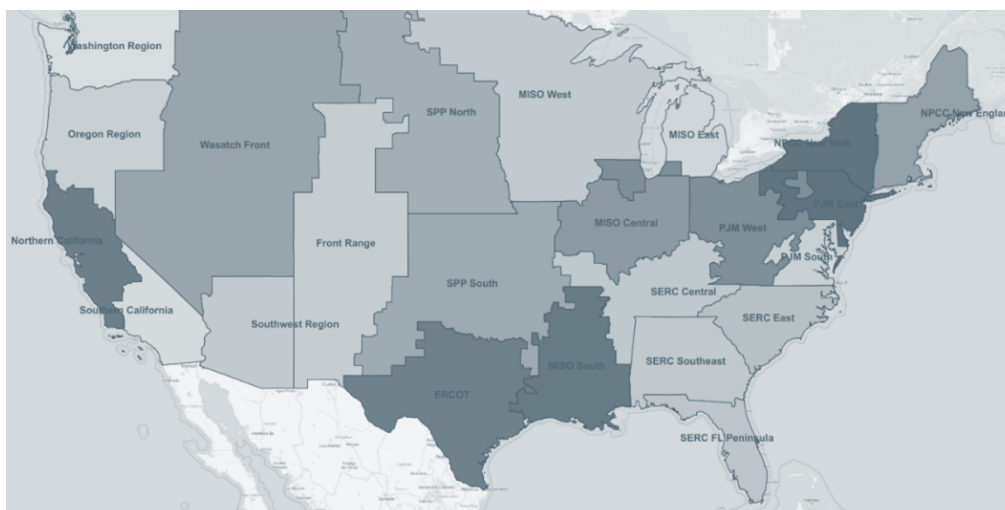


Figure 5. TPRs used in NERC ITCS

13. Energy Exemplar, "PLEXOS," <https://www.energyexemplar.com/plexos>.

14. The TPRs match the regional subdivisions in the NERC ITCS study, itself based on FERC's transmission planning regions.

15. Transmission within ERCOT is intrastate commerce. 16 U.S.C. § 824(b)(1) (provisions applying to "the transmission of electric energy in interstate commerce").

16. NERC "Integrated Transmission and Capacity System (ITCS)," accessed June 25, 2025, <https://www.nerc.com/pa/RAPA/Pages/ITCS.aspx>.

This methodology developed a current model and series of scenarios to explore how different assumptions impact resource adequacy. This sensitivity analysis includes assumptions regarding load growth, generation build-outs and retirements, and transfer capabilities. By comparing the results of the current model with the scenario results, we can assess how generation retirements and load growth affect future generation needs.

The assessment uses data from 2007–2013 (synthetic weather data) and 2019–2023 (historical data). A brief summary of the methodological assumptions is provided here, with additional details available in the relevant appendixes.

- **Solar and Wind Availability** – Created from historical output from EIA 930 data, with bias correction of any nonhistorical data to match regional capacity factors, as calibrated to EIA 930 data.¹⁷ Synthetic years used 2018 technology characteristics from NREL based on the Variable Energy Potential (reV) model, then mapped to synthetic weather year data. See Appendix A for more details.
- **Thermal Availability** – Calculated according to NERC LTRA capacity data, adjusted for historical outages and derates, primarily with GADS data. GADS data does not capture historical outages caused by fuel supply interruptions.¹⁸
- **Hydroelectric Availability** – Historical outputs are processed by NERC to establish monthly power rating limits and energy budgets, but energy budgets are not enforced in alignment with how they were treated in the ITCS. The team evaluated performance under different energy budget restrictions, but did not find significant differences during peak hours, justifying NERC ITCS assumptions that hydroelectric resources could generally be dispatched to peak load conditions. Later work may benefit from exploring drought scenarios or combinations of weather and hydrological years, where energy budgets may be significantly decreased.
- **Outages and Derates** – Data for the actual data period (2019–2023) are based on historical forced outage rates and deratings. Outage and deratings data for the synthetic period (2007–2013) are based on the historical relationships observed between temperature and outages (see Appendix G of the NERC ITCS Final Report for more information).
- **Load Projections and AI Growth** – Load growth through 2030 is assumed to match NERC 2024 ITCS projections, scaling the 12 weather years to meet 2030 projections. Additional AI and data center load is then added according to reports from EPRI and S&P regarding potential futures.
- **Transfer Capabilities and Imports/Exports** - Each subregion is treated as a “copper plate,” with the transfer capacity between each subregion defined by the availability of transmission pathways. It is an approximation that assumes all resources are connected to a single point, simplifying the transmission system within the model. Subregions are generally assumed to exhaust their own capacity before utilizing capacity available from their neighbors. Once the net remaining capacity is at or below 10 percent of load, the subregion begins to use capacity from a neighbor.

17. See ITCS Final Report, Appendix F, for the method that was implemented to scale synthetic weather years 2007–2013.

18. See ITCS Final Report, Appendix G, for outage and derate methods.

- Imports are assumed to be available up to the minimum total transfer capacity and spare generation in the neighboring subregion.
- To the extent the remaining capacity after transmission and demand response falls below the 6 percent or 3 percent needed for error forecasting and ancillary services, depending on the scenario, the model projects an energy shortfall. See “Outputs” in the appendix for more details.
- To ensure that transfers are dispatched only after local resources are exhausted, a wheeling charge of \$1,000 is applied for every megawatt-hour of energy transferred between regions through transmission pathways.
- **Storage** – In alignment with the NERC ITCS methodology, storage was split into pumped hydro and battery storage. Pumped hydro was assumed to have 12 hours duration at rated capacity with 30% round-trip losses, while battery storage was assumed to have four hours and 13% round-trip losses. Storage is dispatched as an optimization to minimize USE and demand response usage under various constraints and is recharged during periods of surplus energy.
- **Demand Response** – Demand Response (DR) is treated as a supply-side resource and dynamically scheduled after all other regional resources and imports are exhausted. It is modeled with both capacity (MW) and energy (MWh) limitations and assumed to have three hours of availability at capacity but could be spread across more than three hours up to the energy limit. DR capacity was based on LTRA Form A data submissions for “Controllable and Dispatchable Demand Response – Available”, or firm, controllable DR capacity.
- **Retirements** – Retirements as per the NERC LTRA 2024 model. To disaggregate generation capacity from the NERC assessment areas to the ITCS regions, EIA 860 plant level data are used to tabulate generation retirement or addition capacity for each ITCS region and NERC assessment area. Disaggregation fractions are then calculated by technology based on planned retirements through 2030. See Appendix B for further information. Retirements are categorized into two categories:
 1. *Announced Retirements*: Includes both confirmed retirements and announced retirements. Confirmed retirements are generators formally recognized by system operators as having started the official retirement process and are assumed to retire on their expected date. To go from LTRA regions to ITCS regions, weighting factors are derived in the same way as in the generation set, based on EIA retirement data. In addition to confirmed retirements, announced retirements are generators that have publicly stated retirement plans that have not formally notified system operators and initiated the retirement process. This disaggregation method for announced retirements mirrors used for confirmed retirements.¹⁹
 2. *None*: Removes all retirements (after 2024) for comparison. Delaying or canceling some near-term retirements may not be feasible, but this case can help determine how much retirement contributes to some of the adequacy challenges in some regions.
- **Additions** – Assumes only projects that are very mature in the pipeline (such as those with a signed interconnection agreement) will be built. This data is based on projects

19. If announced retirements were less than or equal to confirmed retirements, the model adjusted the announced retirement to equal confirmed.

designated as Tier 1 in the NERC 2024 LTRA and are mapped to ITCS regions with EIA 860-derived weighting factors similar to those described for the retirements above. See Appendix A for further information.

- **Perfect Capacity Required** - Estimates perfect capacity (which is idealized capacity that has no outages or profile and is described in Section 2) until we reach a pre-defined reliability target. We used a metric of NUSE given the deterministic nature of the model, to be consistent with evolving metrics, and to be consistent with NERC's recent LTRAs. We targeted NUSE of below 0.002% for each region.

1.1 Modeling Resource Adequacy

This model calculates several reliability metrics to assess resource adequacy. These metrics were calculated using PLEXOS simulation outputs, which report the USE (in MWh) for all 8,760 hourly periods in each of the 12 weather years:

- **USE** refers to the amount of electricity demand that could not be met due to insufficient generation and/or transmission capacity. Several USE-derived indicators were considered:
 - *Normalized USE (percentage %)*: The total amount of unserved load over 12 years of weather data, normalized by dividing by total load, and reported as a percentage.²⁰
 - *Mean Annual USE (GWh)*: The 12-year average of each region's total USE in each weather year. This mean value represents the average annual USE across weather variability.
 - *Mean Max Unserved Power (GW)*: The 12-year average of each region's maximum USE value in each weather year. This mean value characterizes the typical non-coincident peak stress on system reliability.
 - *% Max Unserved Power*: The Mean Max Unserved Power expressed as a percentage of the average native load during those peak unserved hours for each region. This percentage value provides a normalized measure of the severity of peak unserved events relative to demand.
 - *Total number of customers without power*. The Mean Max Unserved Power expressed as the equivalent number of typical U.S. persons assuming a ratio of 17,625 persons/MW lost. This estimation contextualizes the effects of the outage on average Americans.
- **Loss of Load Hours (LOLH)** refers to the number of hours during which the system experiences USE (i.e., any hour with non-zero USE). Two LOLH-based indicators were considered:

20. NUSE can be reported as parts per million or as a percentage (or parts per hundred); though for power system reliability, this would include several zeros after the decimal point.

- *Mean Annual LOLH*: for each weather year and *TPR*, we count the total number of hours with USE across all 8,760 hours, and we then take the average of those 12 totals. *Annual LOLH Distribution* is represented in box and whisker plots for 12 samples, each sample corresponding to a unique weather year.
- *Max Consecutive LOLH (hours)*²¹: The longest continuous period with reported USE in each weather year.

It should be noted that USE is not an indication that reliability coordinators would allow this level of load growth to jeopardize the reliability of the system. Rather, it represents the unrealizable AI and data center load growth under the given assumptions for generator build outs by 2030, generator retirements by 2030, reserve requirements, and potential load growth. These numbers are used as indicators to determine where it may be beneficial to encourage increased generation and transmission capacity to meet an expected need.

This study does not employ common probabilistic industry metrics such as EUE or LOLE due to their reliance on probabilistic modeling. Instead, deterministic equivalents are used.

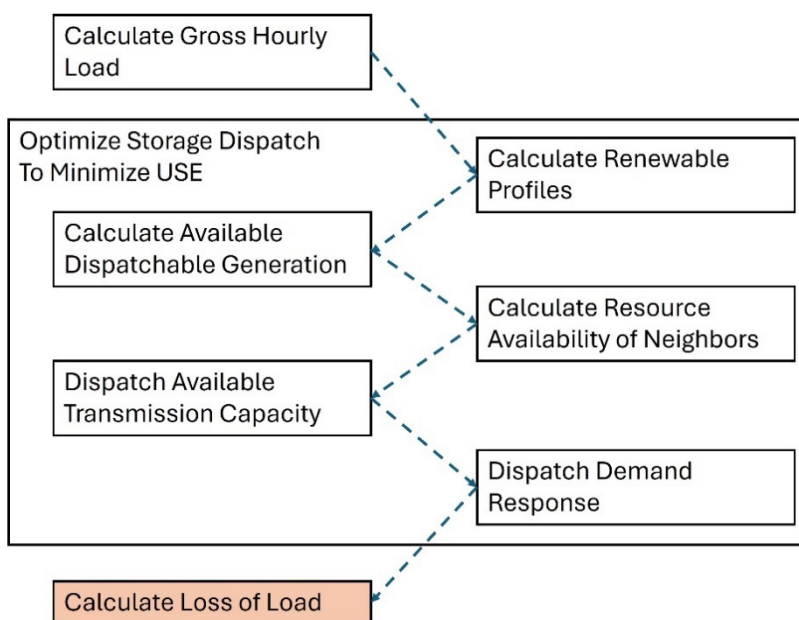


Figure 6. Simplified Overview of Model

21. One caveat on the maximum consecutive LOLH and max USE values is in how storage is dispatched in the model. Storage is dispatched to minimize the overall USE and is indifferent to the peak depth or the duration of the event. This may construe some of the max USE and max consecutive LOLH values to be higher than if storage was dispatched to minimize these values.

1.2 Planning Years and Weather Years

For the planning year (2030), historical weather year data are applied based on conditions between 2007 and 2024 to calculate load, wind and solar generation, and hydro generation. Dispatchable capacity (including dispatchable hydro capacity) is calculated through adjustment of the 2024 LTRA capacity data for historical outages from GADS data. Storage assets are scheduled to arbitrage hourly energy margins or else charge during periods of high energy margins (surplus resources) and discharge during periods of lower energy margins.

1.3 Load Modeling

Data Center Growth

Several utilities and financial and industry analysts identify data centers, particularly those supporting AI workloads, as a key driver of electricity demand growth. Multiple organizations have developed a wide range of projections for U.S. data center electricity use through 2030 and beyond, each using distinct methodologies tailored to their institutional expertise.

These datasets were used to explore reasonable boundaries for what different parts of the economy envision for the future state of AI and data center (AI/DC) load growth. For the purposes of this study, rather than focusing on any specific analysis, a more generic sweep was performed across AI/DC load growth and the various sensitivities that fit within those assumptions, as summarized below:

- McKinsey & Company projects ~10% annual growth in U.S. data center electricity demand, reaching 2,445 TWh by 2050. Their model blends internal scenarios with public signals, including announced projects, capital investment, server shipments, and chip-level power trends, supported by third-party market data.
- Lawrence Berkeley National Laboratory (LBNL) uses a bottom-up approach based on historical and projected IT equipment shipments, paired with assumptions on power draw, utilization, and infrastructure efficiency (PUE, WUE). Their projections through 2028 account for AI hardware adoption, operational shifts, and evolving cooling technologies.
- EPRI combines public data, expert input, and historical trends to define four national growth scenarios, low to higher, for 2023–2030, reflecting data processing demand, efficiency improvements, and AI-driven load impacts.
- S&P Global merges technology and power-sector models, evaluating grid readiness and facility growth under varying demand scenarios. Their forecasts consider AI adoption, efficiency trends, grid and permitting constraints, on-site generation, and offshoring risk, resulting in a wide range of outcomes.

These projections show wide variation, with 2030 electricity demand ranging from approximately 35 GW to 108 GW of average load. Given this uncertainty, including differences in hardware intensity, thermal management, siting assumptions, and behind-the-meter generation, the modeling team adopted a national midpoint assumption of approximately 50 GW by 2030.

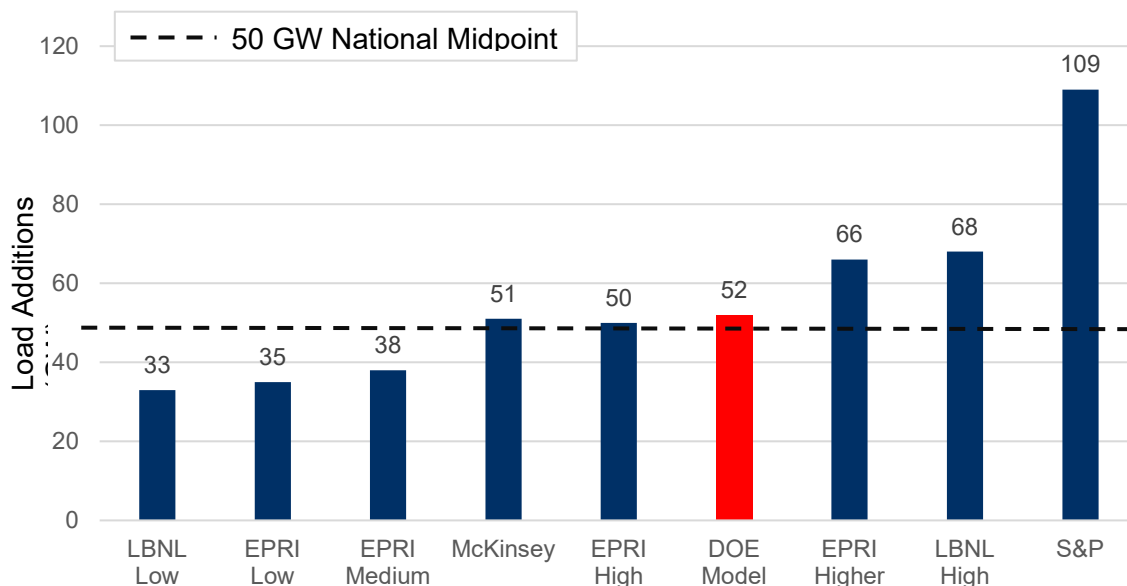


Figure 7. 2024 to 2030 Projected Data Center Load Additions

Figure 2 above displays a benchmark reflecting the median across major studies and aligns with central projections from EPRI and LBNL. Using a single planning midpoint avoids double counting and enables consistent load allocation across national transmission and resource adequacy models.

Data Center Allocation Method

To allocate the 50 GW midpoint regionally, the team used state-level growth ratios from S&P's forecast. These ratios reflect factors such as infrastructure, siting trends, and projected market activity. The modeling team mapped the state-level projections to NERC TPRs, ensuring transparent and repeatable regional allocation. While other methods exist, this approach ensured consistency with the broader modeling framework.

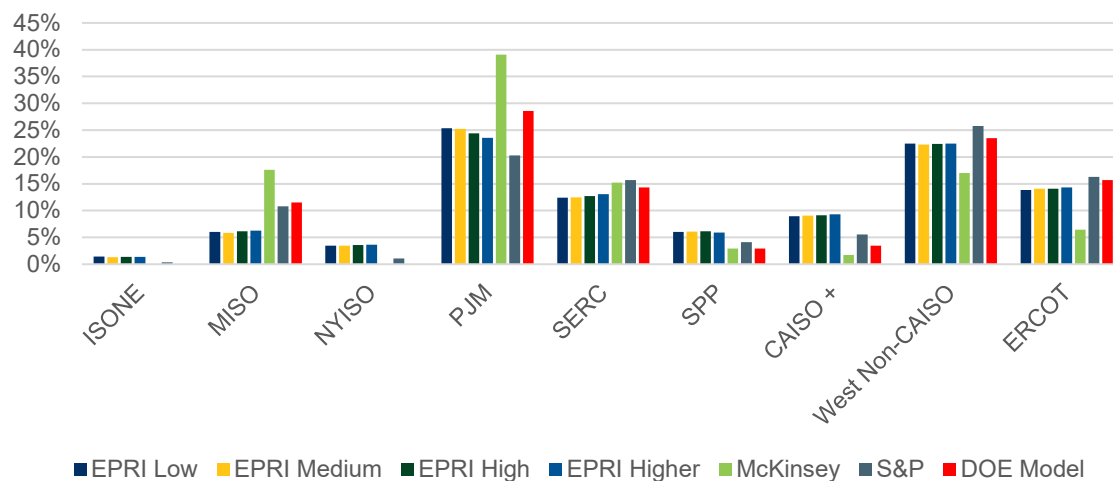


Figure 8. New Data Center Build (% Split by ISO/RTO) (2030 Estimated)

Non-Data Center Load Modeling

The current electricity demand projections were built from NERC data, using historical load (2019–2023) and simulated weather years (2007–2013). These were adjusted based on the EIA's 2022 energy forecast. To estimate 2030 demand, the team interpolated between 2024 and 2033, scaling loads to reflect energy use and seasonal peaks. NERC provided datasets to address anomalies and include behind-the-meter and USE.

Given the rapid emergence of AI/DC loads, additional steps were taken to account for this category of demand. It is difficult to determine how much AI/DC load is already embedded in NERC LTRA forecast, for example, the 2024 LTRA saw more than 50GW increase from 2023, signaling a major shift in utility expectations. To benchmark existing AI/DC contribution, DOE assumed base 2023 AI/DC load equaled the EPRI low-growth case of 166 TWh.

Overall Impact on Projected Peak Load

As a result of the methods applied above, the average year co-incident peak load is projected to grow from a current average peak of 774 GW to 889 GW in 2030. This represents a 15% increase or 2.3% growth rate per year. Excluding the impact of data centers, this would amount to a 51GW increase from 774 GW to 826 GW which represents a 1.1% annual growth rate.

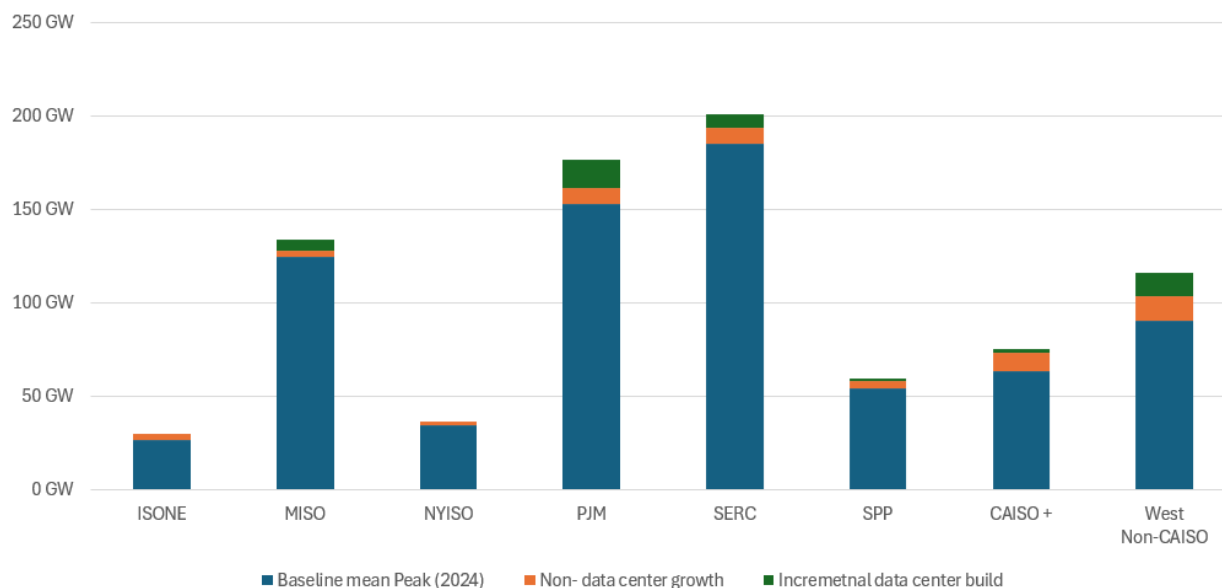


Figure 9. Mean Peak Load by RTO (Current Case vs 2030 Case)

1.4 Transfer Capabilities and Import Export Modeling

The methodology assumes electricity moves between subregions, when conditions start to tighten. Each region has a certain amount of capacity available, and the methodology determines if there is enough to meet the demand. When regions reach a “Tight Margin Level” of 10% of capacity, i.e., if a region’s available capacity is less than 110% of load, it will start transferring from other regions if capacity is available. A scarcity factor is used to determine which regions to transfer from and at what fraction – those with a greater amount of reserve capacity will transfer more. A region is only allowed to export above when it is above the Tight Margin Level.

Total Transfer Capability (TTC) was used and is the sum of the Base Transfer Level and the First Contingency Incremental Transfer Capability. These were derived from scheduled interchange tables or approximated from actual line flows. It should be noted that the TTC does not represent a single line, but rather multiple connections between regions. It is similar to path limits used by many entities but may have different values.

Due to data and privacy limitations, the Canadian power system was not modeled directly as a combination of generation capacity and demand. Instead, actual hourly imports were used from nearly 20 years of historical data, along with recent trends (generally less transfers available during peak hours), to develop daily limits on transfer capabilities. See Appendix B for more details on Canadian transfer limits.

1.5 Perfect Capacity Additions

To understand how much capacity may need to be added to reach approximate reliability targets, we tuned two scenarios by adding hypothetical perfect capacity to reach the reliability threshold based on NUSE.²² Today, NERC uses a threshold of 0.002% to indicate regions are at high risk of resource adequacy shortfalls. In addition, several system operators, including the Australia Energy Market Operator and Alberta Electric System Operator, are using NUSE thresholds in the range of 0.001% to 0.003%. Several U.S. entities are considering lower thresholds for U.S. power systems in the range of 0.0001% to 0.0002%.²³

For this analysis, we target NUSE below 0.002% for each region to align with NERC definitions. We iteratively ran the model, hand-tuning the “perfect capacity” to be as small as possible while reaching NUSE values below 0.002% in all regions.²⁴ As the work was done by hand with a limited number of iterations (15), this should not be considered the minimum possible capacity to accomplish these targets. Further, because the perfect capacity can be located in various places, there would be multiple potential solutions to the problem. These scenarios represent the approximate quantity of perfect capacity each region would require (beyond announced retirements and mature generation additions only) that would lead to Medium or Low risk based on the NERC metrics for USE.

Due to some regions with zero USE, the tuned cases do not reach the same level of adequacy, where the national average is 0.00045% vs. 0.00013%. Due to transmission and siting selection of perfect capacity, there could be many solutions.

22. We are not using the standard term “expected unserved energy” because we are not running a probabilistic model, so we do not have the full understanding of long-term expectations

23. MISO, “Resource Adequacy Metrics and Criteria Roadmap,” December 2024.
<https://cdn.misoenergy.org/Resource%20Adequacy%20Metrics%20and%20Criteria%20Roadmap667168.pdf>.

24. NERC, “Evolving Criteria for a Sustainable Power Grid,” July 2024.
https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Evolving_Planning_Criteria_for_a_Sustainable_Power_Grid.pdf.

2 Regional Analysis

This section presents more regional details on resource adequacy according to this analysis. For each of the nine Regional Transmission Organizations (RTOs) and sub-regions, comprehensive summaries are provided of reliability metrics, load assumptions, and composition of generation stacks.

2.1 MISO²⁵

In the current system model and the No Plant Closures cases, MISO did not experience shortfall events. MISO's minimum spare capacity in the tightest year was negative, showing that adequacy was achieved by importing power from neighbors. In the Plant Closures case, MISO experienced significant shortfalls, with key reliability metrics exceeding each of the threshold criteria defined for the study.

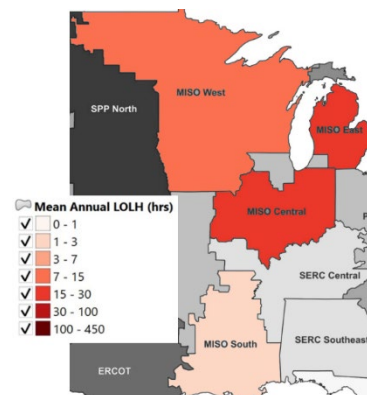


Table 2. Summary of MISO Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	-	37.8	-	-
Normalized Unserved Energy (%)	-	0.0211	-	-
Unserved Load (MWh)	-	157,599	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	-	124	-	-
Normalized Unserved Load (%)	-	0.0702	-	-
Unserved Load (MWh)	-	524,180	-	-

Load Assumptions

MISO's peak load was roughly 130 GW in the current model and projected to increase to roughly 140 GW by 2030. Approximately 6 GW of this relates to new data centers being installed (12% of U.S. total).

25. Following the initial data collection for this report, MISO issued its 2025 Summer Reliability Assessment. Based on that report, NERC revised evaluations from its 2024 LTRA and reclassified the MISO footprint from being an 'elevated risk' to 'high risk' in the 2028–2031 timeframe, depending on new resource additions/retirements. While DOE's analysis is based on the previously reported figures, DOE is committed to assessing the implications of updated data on overall resource adequacy and providing technical updates on findings, as appropriate.

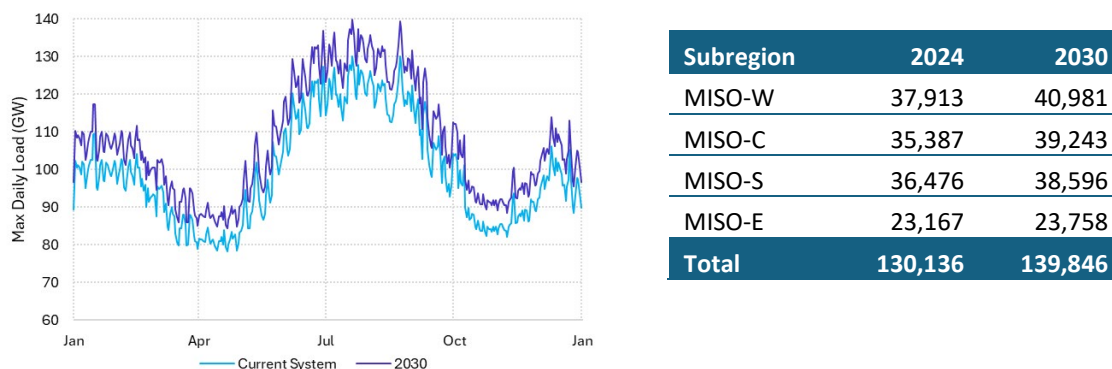


Figure 10. MISO Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 207 GW.²⁶ In 2030, 21 GW of new capacity was added leading to 228 GW of capacity in the No Plant Closures case. In the Plant Closures case, 32 GW of capacity was retired such that net retirements in the Plant Closures case were -11 GW, or 196 GW of overall installed capacity on the system.

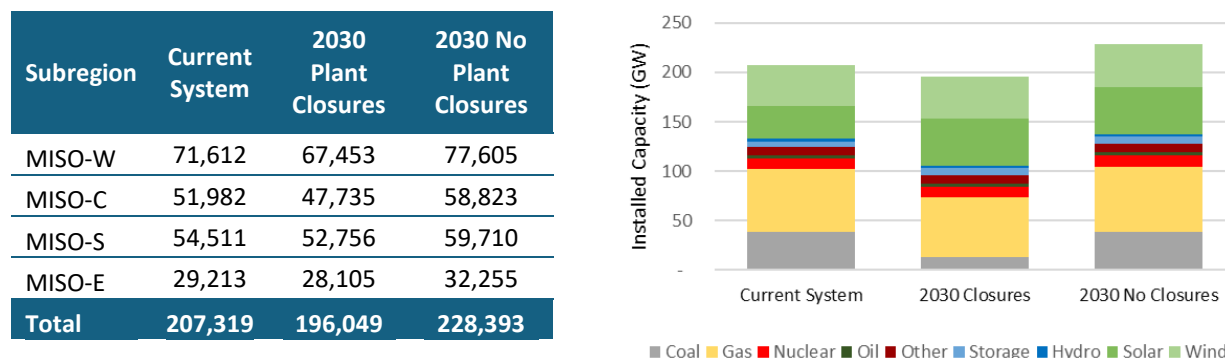


Figure 11. MISO Generation Capacity by Technology and Scenario

MISO's generation mix was comprised primarily of natural gas, coal, wind, and solar. In 2024, natural gas comprised 31% of nameplate, wind comprised 20%, coal 18%, and solar 14%. In 2030, most retirements come from coal and natural gas while additions occur for solar, batteries, and wind. In addition, the model assumed 3 GW of rooftop solar and 8 GW of demand response.

26. The total installed capacity numbers reported in this regional analysis section do not reflect the generating capability of all resources during stress conditions.

Table 3. Nameplate Capacity by MISO Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	37,914	64,194	11,127	2,867	8,717	5,427	2,533	32,826	41,715	207,319
MISO-W	12,651	13,608	2,753	1,491	2,613	200	777	8,109	29,411	71,612
MISO-C	15,050	10,307	2,169	494	2,211	1,272	769	12,361	7,350	51,982
MISO-S	5,493	31,052	5,100	589	2,469	54	845	8,315	596	54,511
MISO-E	4,720	9,227	1,105	292	1,424	3,901	143	4,042	4,359	29,213
Additions	0	2,535	0	330	0	1,929	0	14,354	1,926	21,074
MISO-W	0	537	0	172	0	374	0	3,552	1,358	5,993
MISO-C	0	407	0	57	0	934	0	5,103	339	6,841
MISO-S	0	1,226	0	68	0	9	0	3,868	27	5,199
MISO-E	0	364	0	34	0	611	0	1,831	201	3,042
Closures	(24,913)	(6,597)	0	(324)	(140)	(16)	(83)	0	(272)	(32,345)
MISO-W	(8,313)	(1,398)	0	(168)	(56)	0	(25)	0	(192)	(10,152)
MISO-C	(9,889)	(1,059)	0	(56)	(7)	(3)	(25)	0	(48)	(11,088)
MISO-S	(3,609)	(3,191)	0	(67)	(55)	(0)	(28)	0	(4)	(6,954)
MISO-E	(3,102)	(948)	0	(33)	(21)	(13)	(5)	0	(28)	(4,150)

2.2 ISO-NE

In the current system model and the No Plant Closures case, ISO-NE did not experience shortfall events. The region maintained adequacy throughout the study period through reliance on imports. In the Plant Closures case, ISO-NE still did not exceed any key reliability thresholds, despite moderate retirements. This finding is partly due to the absence of additional AI or data center load growth modeled in the region. Accordingly, no additional perfect capacity was deemed necessary by 2030 to meet the study’s reliability standards.

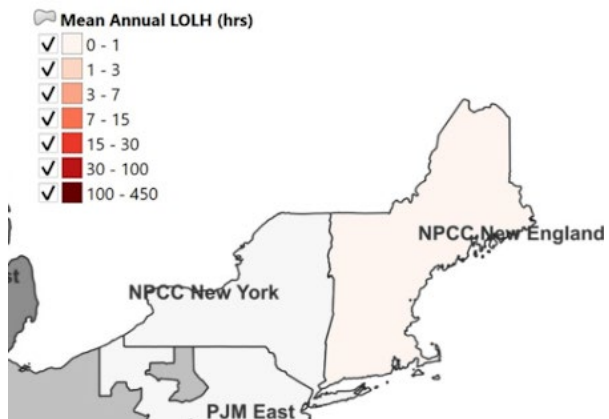
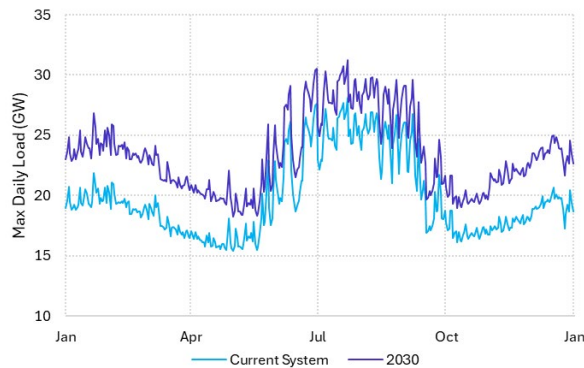


Table 4. Summary of ISO-NE Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	-	-	-	-
Normalized Unserved Energy (%)	-	-	-	-
Unserved Load (MWh)	-	-	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	-	-	-	-
Normalized Unserved Load (%)	-	-	-	-
Unserved Load (MWh)	-	-	-	-
Max Unserved Load (MW)	-	-	-	-

Load Assumptions

ISO-NE’s peak load was roughly 28 GW in the current model and projected to increase to roughly 31 GW by 2030. No additional AI/DCs were projected to be installed.



Subregion	2024	2030
ISO-NE	28,128	31,261
Total	28,128	31,261

Figure 12. ISO-NE Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 40 GW. In 2030, 5.5 GW of new capacity was added leading to 45.5 GW of capacity in the No Plant Closures case. In the Plant Closures case, 2.7 GW of capacity was retired such that net generation change in the Plant Closures case was +11 GW, or 42.8 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
ISO-NE	39,979	42,845	45,534
Total	39,979	42,845	45,534

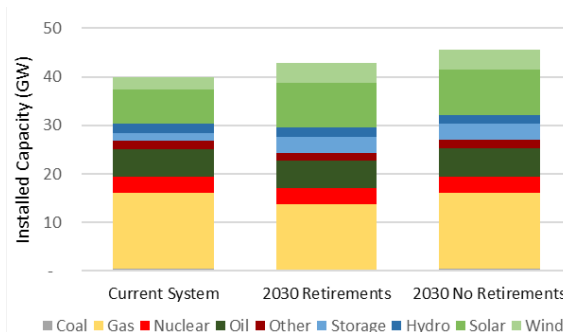


Figure 13. ISO-NE Generation Capacity by Technology and Scenario

ISO-NE's generation mix was comprised primarily of natural gas, solar, oil, and nuclear. In 2024, natural gas comprised 39% of nameplate, solar comprised 17%, oil 14%, and nuclear 8%. In 2030, most retirements come from coal and natural gas while additions occur for solar, storage, and wind. The model assumed nearly 2 GW of rooftop solar and 1.6 GW of energy storage.

Table 5. Nameplate Capacity by ISO-NE Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	541	15,494	3,331	5,710	1,712	1,628	1,911	7,099	2,553	39,979
ISONE	541	15,494	3,331	5,710	1,712	1,628	1,911	7,099	2,553	39,979
Additions	0	90	0	181	0	1,607	0	2,183	1,495	5,555
ISONE	0	90	0	181	0	1,607	0	2,183	1,495	5,555
Closures	(534)	(1,875)	0	(203)	(77)	0	0	0	0	(2,690)
ISONE	(534)	(1,875)	0	(203)	(77)	0	0	0	0	(2,690)

2.3 NYISO

In both the current system model and the No Plant Closures case, NYISO maintained reliability and did not exceed any shortfall thresholds. Adequacy was preserved through reliance on imports. In the Plant Closures case, NYISO experienced shortfalls but average annual LOLH remaining well below the 2.4-hour threshold and NUSE under the 0.002% standard. The worst weather year produced only 6 hours of lost load and a peak unserved load of 914 MW. Given the modest impact of retirements and no additional AI/data center load modeled, the study concluded that NYISO would not require additional perfect capacity to remain reliable through 2030.

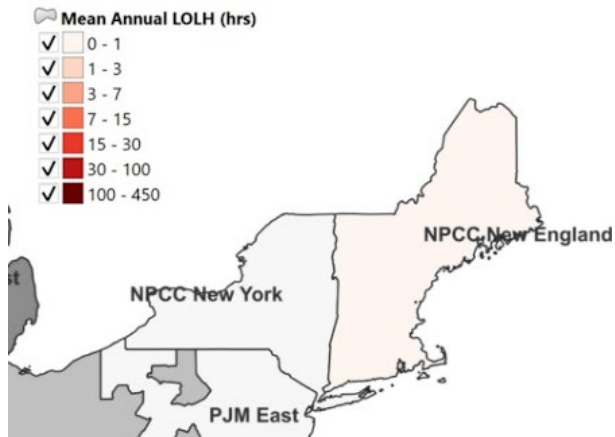


Table 6. Summary of NYISO Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	0.2	0.5	-	-
Normalized Unserved Energy (%)	0.00001	0.0001	-	-
Unserved Load (MWh)	18	209	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	2	6	-	-
Normalized Unserved Load (%)	0.0001	0.0013	-	-
Unserved Load (MWh)	216	2,505	-	-
Max Unserved Load (MW)	194	914	-	-

Load Assumptions

NYISO’s peak load was roughly 36 GW in the current system model and projected to increase to roughly 38 GW by 2030. No additional AI/DCs were projected to be installed.

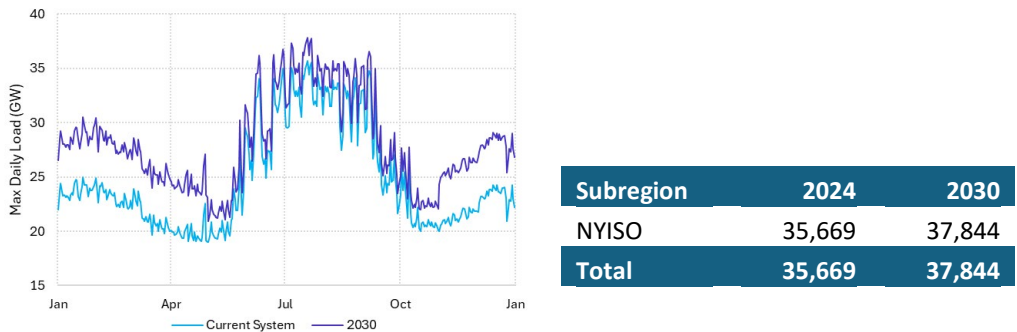


Figure 14. NYISO Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 46 GW. In 2030, 5.5 GW of new capacity was added leading to 51 GW of capacity in the No Plant Closures case. In the Plant Closures case, 1 GW of capacity was retired such that net generation in the Plant Closures case was +4 GW, or 50 GW of overall installed capacity on the system.

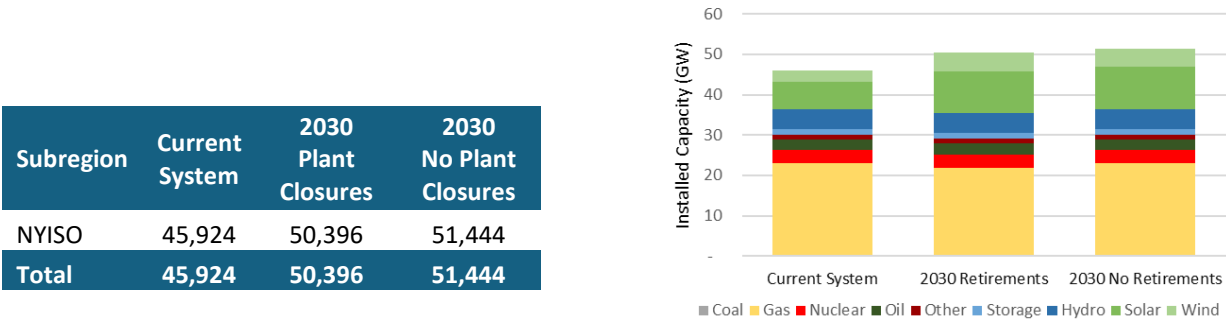


Figure 15. NYISO Generation Capacity by Technology and Scenario

NYISO’s generation mix was comprised primarily of natural gas, solar, and hydro. In 2024, natural gas comprised 50% of total nameplate generation, solar comprised 14%, and hydro 11%. In 2030, most retirements come from natural gas while additions occur for solar and wind. The model assumed 6 GW of rooftop solar and nearly 1 GW of demand response.

Table 7. Nameplate Capacity by NYISO Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	0	22,937	3,330	2,631	1,194	1,460	4,915	6,749	2,706	45,924
NYISO	0	22,937	3,330	2,631	1,194	1,460	4,915	6,749	2,706	45,924
Additions	0	0	0	15	0	0	0	3,604	1,902	5,521
NYISO	0	0	0	15	0	0	0	3,604	1,902	5,521
Closures	0	(1,030)	0	(19)	0	0	0	0	0	(1,049)
NYISO	0	(1,030)	0	(19)	0	0	0	0	0	(1,049)

2.4 PJM

In the current system model, PJM experienced shortfalls, but they were below the required threshold. In the No Plant Closures case, shortfalls increased dramatically, with 214 average annual LOLH and peak unserved load reaching 17,620 MW, indicating growing strain even without retirements. In the Plant Closures case, reliability metrics worsened significantly, with annual LOLH surging to over 430 hours per year and NUSE reaching 0.1473%—over 70 times the accepted threshold. During the worst weather year, 1,052 hours of load were shed. To restore reliability, the study found that PJM would require 10,500 MW of additional perfect capacity by 2030.

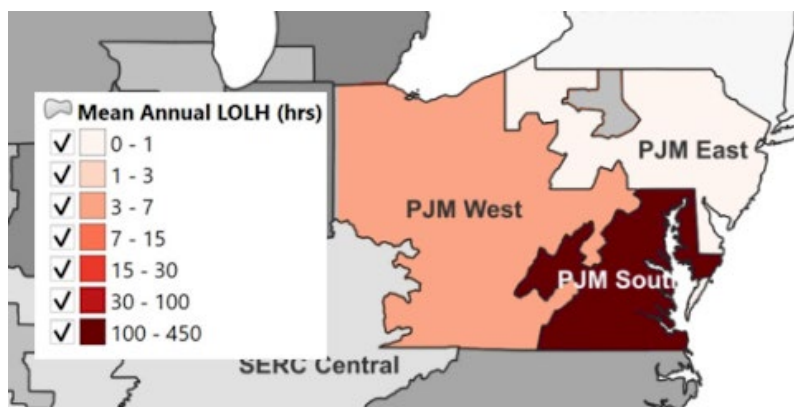
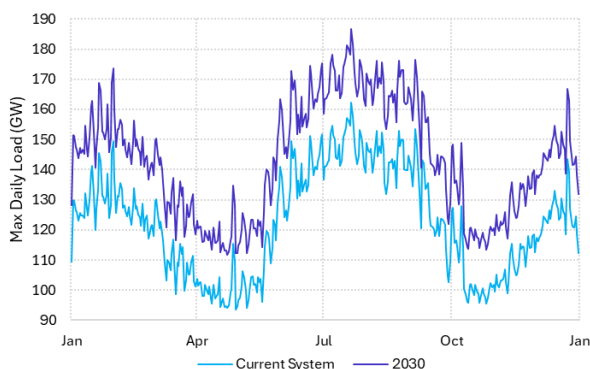


Table 8. Summary of PJM Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	2.4	430.3	213.7	1.4
Normalized Unserved Energy (%)	0.0008	0.1473	0.0657	0.0003
Unserved Load (MWh)	6,891	1,453,513	647,893	2,536
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	29	1,052	644	17
Normalized Unserved Load (%)	0.0100	0.4580	0.2703	0.0031
Unserved Load (MWh)	82,687	1,453,513	647,893	2,536
Max Unserved Load (MW)	4,975	21,335	17,620	4,162

Load Assumptions

PJM's peak load was roughly 162 GW in the current system model and projected to increase to roughly 187 GW by 2030. Approximately 15 GW of this relates to new AI/DC being installed (29% of U.S. total), primarily in PJM-S.



Subregion	2024	2030
PJM-W	81,541	92,378
PJM-S	39,904	51,151
PJM-E	41,003	43,118
Total	162,269	186,627

Figure 16. PJM Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 215 GW. In 2030, 39 GW of new capacity was added leading to 254 GW of capacity in the No Plant Closures case. In the Plant Closures case, 17 GW of capacity was retired such that net generation in the Plant Closures case was +22 GW, or 237 GW of overall nameplate capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
PJM-W	114,467	123,100	135,810
PJM-S	39,951	48,850	50,667
PJM-E	60,221	64,848	67,027
Total	214,638	236,798	253,504

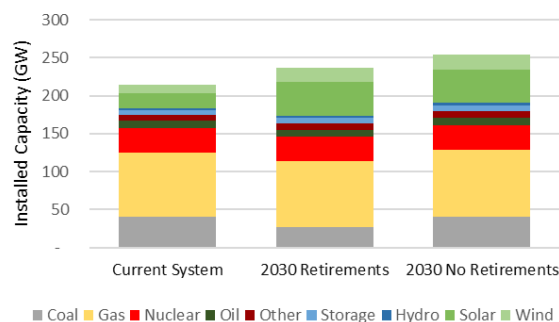


Figure 17. PJM Generation Capacity by Technology and Scenario

PJM's generation mix was comprised primarily of natural gas, coal, and nuclear. In 2024, natural gas comprised 39% of nameplate, coal comprised 19%, and nuclear 15%. In 2030, most retirements come from coal and some natural gas and oil while significant additions occur for solar plus lesser additions of wind, storage, and natural gas. The model assumed 9 GW of rooftop solar and 7 GW of demand response.

Table 9. Nameplate Capacity by PJM Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	39,915	84,381	32,535	9,875	8,248	5,400	3,071	19,495	11,718	214,638
PJM-W	34,917	39,056	16,557	1,933	3,926	383	1,252	6,379	10,065	114,467
PJM-S	2,391	15,038	5,288	3,985	2,303	3,085	1,070	6,430	360	39,951
PJM-E	2,608	30,287	10,690	3,956	2,019	1,932	749	6,686	1,294	60,221
Additions	0	4,499	0	32	317	1,938	0	24,991	7,089	38,866
PJM-W	0	2,082	0	6	135	855	0	12,176	6,089	21,343
PJM-S	0	802	0	13	102	726	0	8,856	218	10,717
PJM-E	0	1,615	0	13	81	357	0	3,958	783	6,806
Closures	(13,253)	(1,652)	0	(1,790)	(11)	0	0	0	0	(16,706)
PJM-W	(11,593)	(765)	0	(350)	(1)	0	0	0	0	(12,710)
PJM-S	(794)	(294)	0	(722)	(6)	0	0	0	0	(1,817)
PJM-E	(866)	(593)	0	(717)	(3)	0	0	0	0	(2,179)

2.5 SERC

In the current system model and the No Plant Closures case, SERC maintained overall adequacy, though some subregions—particularly SERC-East—faced emerging winter reliability risks. In the Plant Closures case, shortfalls became more severe, with SERC-East experiencing increased unserved energy and loss of load hours during extreme cold events, including 42 hours of outages in a single winter storm. The analysis identified that planned retirements, combined with rising winter load from electrification, would stress the system. To restore reliability in SERC-East, the study found that 500 MW of additional perfect capacity would be needed by 2030. Other SERC subregions performed adequately, but continued monitoring is warranted due to shifting seasonal peaks and fuel supply vulnerabilities.

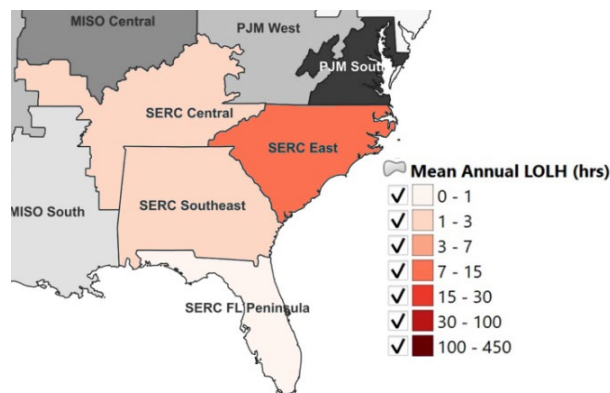
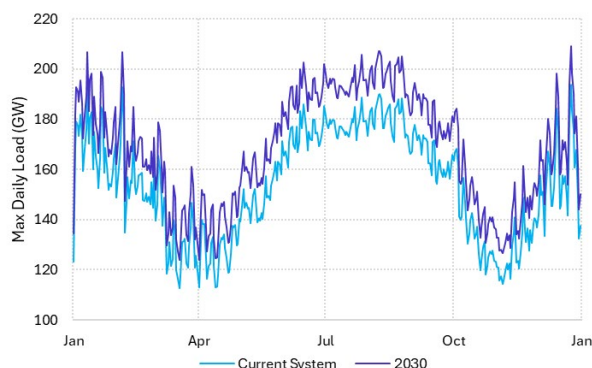


Table 10. Summary of SERC Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	0.3	8.1	1.2	0.8
Normalized Unserved Energy (%)	0.0001	0.0041	0.0004	0.0002
Unserved Load (MWh)	489	44,514	3,748	2,373
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	4	42	14	10
Normalized Unserved Load (%)	0.0006	0.0428	0.0042	0.0026
Unserved Load (MWh)	5,683	465,392	44,977	2,373
Max Unserved Load (MW)	2,373	19,381	6,359	5,859

Load Assumptions

SERC's peak load was roughly 193 GW in the current system model and projected to increase to roughly 209 GW by 2030. Approximately 7.5 GW of this relates to new AI/DCs being installed (14% of U.S. total).



Subregion	2024	2030
SERC-C	50,787	52,153
SERC-SE	48,235	54,174
SERC-FL	58,882	62,572
SERC-E	51,693	56,313
Total	193,654	209,269

Figure 18. SERC Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 254 GW. In 2030, 26 GW of new capacity was added leading to 279 GW of capacity in the No Plant Closures case. In the Plant Closures case, 19 GW of capacity was retired such that net generation change in the Plant Closures case was +7 GW, or 260 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
SERC-C	53,978	54,014	59,660
SERC-SE	67,073	64,768	69,478
SERC-FL	72,714	83,127	86,173
SERC-E	59,914	58,513	63,973
Total	253,680	260,423	279,285

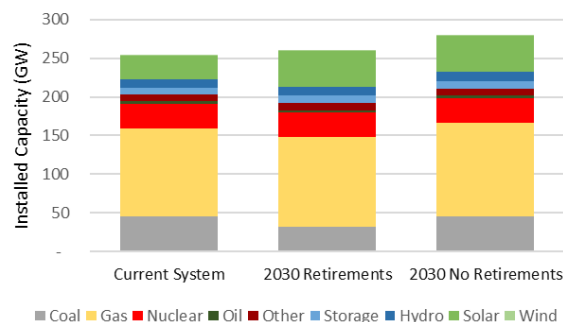


Figure 19. SERC Generation Capacity by Technology and Scenario

SERC's generation mix was comprised primarily of natural gas, coal, nuclear, and solar. In 2024, natural gas comprised 45% of nameplate, coal comprised 18%, nuclear 12%, and solar 11%. In 2030, most retirements come from coal and natural gas while additions occur for solar and some storage. The model assumed 3 GW of rooftop solar and 8 GW of demand response.

Table 11. Nameplate Capacity by SERC Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	45,747	113,334	31,702	4,063	8,779	7,469	11,425	30,180	982	253,680
SERC-C	13,348	20,127	8,280	148	1,887	1,884	4,995	2,328	982	53,978
SERC-SE	13,275	29,866	8,018	915	2,493	1,662	3,260	7,584	0	67,073
SERC-FL	4,346	47,002	3,502	1,957	3,198	538	0	12,172	0	72,714
SERC-E	14,777	16,340	11,902	1,044	1,202	3,384	3,170	8,096	0	59,914
Additions	0	6,898	0	0	381	2,254	0	16,073	0	25,606
SERC-C	0	4,831	0	0	0	80	0	771	0	5,682
SERC-SE	0	906	0	0	19	0	0	3,135	0	4,059
SERC-FL	0	1,161	0	0	218	1,670	0	10,410	0	13,459
SERC-E	0	0	0	0	144	504	0	1,757	0	2,405
Closures	(14,075)	(4,115)	0	(672)	0	0	0	0	0	(18,862)
SERC-C	(4,465)	(1,181)	0	0	0	0	0	0	0	(5,646)
SERC-SE	(5,160)	(124)	0	(176)	0	0	0	0	0	(5,460)
SERC-FL	(1,495)	(1,071)	0	(480)	0	0	0	0	0	(3,046)
SERC-E	(2,955)	(1,739)	0	(16)	0	0	0	0	0	(4,710)

2.6 SPP

In the current system model, SPP experienced shortfalls, but they were below the required threshold. Adequacy was preserved through reliance on imports. In the No Plant Closures case, SPP experienced persistent reliability challenges, with average annual LOLH reaching approximately 48 hours per year and peak hourly shortfalls affecting up to 19% of demand. In the Plant Closures case, system conditions deteriorated further, with unserved energy and outage hours increasing substantially. These shortfalls were concentrated in the northern subregion, which lacks the firm generation and import capacity needed to meet peak winter demand. The analysis determined that 1,500 MW of additional perfect capacity would be needed in SPP by 2030 to restore reliability.

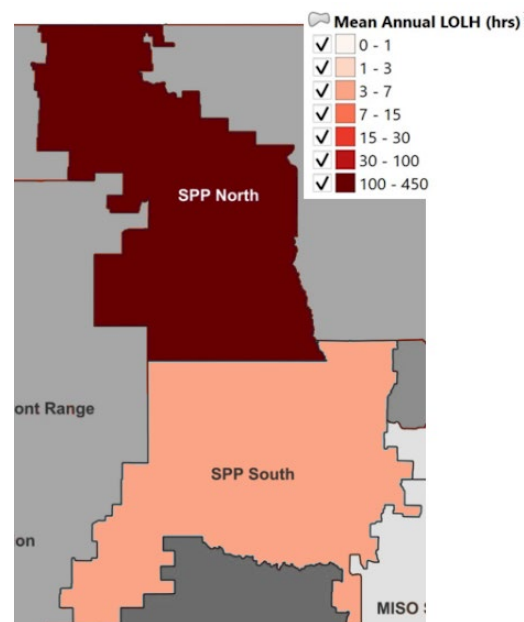
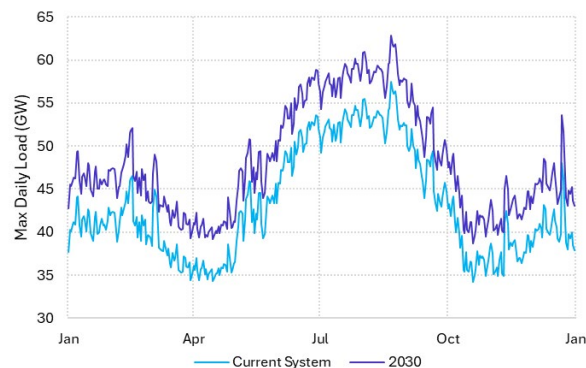


Table 12. Summary of SPP Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	1.7	379.6	47.8	2.4
Normalized Unserved Energy (%)	0.0002	0.0911	0.0081	0.0002
Unserved Load (MWh)	541	313,797	27,697	803
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	20	556	186	26
Normalized Unserved Load (%)	0.0022	0.2629	0.0475	0.0027
Unserved Load (MWh)	6,492	907,518	163,775	9,433
Max Unserved Load (MW)	606	13,263	2,432	762

Load Assumptions

SPP's peak load was roughly 57 GW in the current system model and projected to increase to roughly 63 GW by 2030. Approximately 1.5 GW of this relates to new AI/DCs being installed (3% of U.S. total).



Subregion	2024	2030
SPP-N	12,668	14,676
SPP-S	44,898	48,337
Total	57,449	62,891

Figure 20. SPP Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was 95 GW. In 2030, 15 GW of new capacity was added leading to 110 GW of capacity in the No Plant Closures case. In the Plant Closures case, 7 GW of capacity was retired such that net generation change in the 2030 Plant Closures case was +8 GW, or 103 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
SPP-N	20,065	20,679	22,385
SPP-S	75,078	82,451	88,064
Total	95,142	103,130	110,449

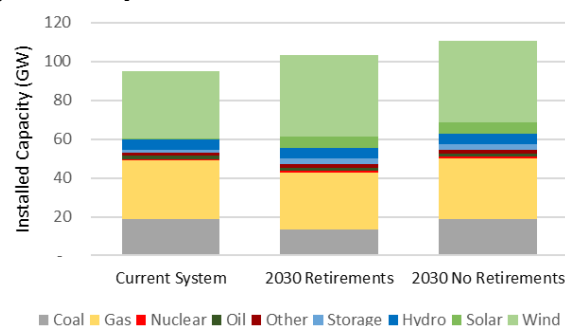


Figure 21. SPP Generation Capacity by Technology and Scenario

SPP's generation mix was comprised primarily of wind, natural gas, and coal. In 2024, wind comprised 36% of nameplate, natural gas comprised 32%, and coal 20%. In the 2030 case, most retirements come from coal and natural gas while additions occur for wind, solar, storage, and natural gas. The model assumed almost no rooftop solar and 1.3 GW of demand response.

Table 13. Nameplate Capacity by SPP Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	18,919	30,003	769	1,626	1,718	1,522	5,123	774	34,689	95,142
SPP-N	5,089	3,467	304	504	519	8	3,041	91	7,041	20,065
SPP-S	13,829	26,536	465	1,121	1,199	1,514	2,082	683	27,649	75,078
Additions	0	1,094	0	7	462	1,390	0	5,288	7,066	15,306
SPP-N	0	126	0	2	114	11	0	633	1,434	2,320
SPP-S	0	968	0	5	348	1,379	0	4,655	5,632	12,987
Closures	(5,530)	(1,732)	0	(56)	0	0	0	0	0	(7,318)
SPP-N	(1,488)	(200)	0	(17)	0	0	0	0	0	(1,705)
SPP-S	(4,042)	(1,532)	0	(39)	0	0	0	0	0	(5,613)

2.7 CAISO+

In the current system and No Plant Closures cases, CAISO+ did not experience major reliability issues, though adequacy was often maintained through significant imports during tight conditions. In the Plant Closures case, however, the region faced substantial shortfalls, particularly during summer evening hours when solar output declines. Average LOLH reached 7 hours per year, and the worst-case year showed load shed events affecting up to 31% of demand. The NUSE exceeded reliability thresholds, signaling the system’s vulnerability to high load and low renewable output periods.

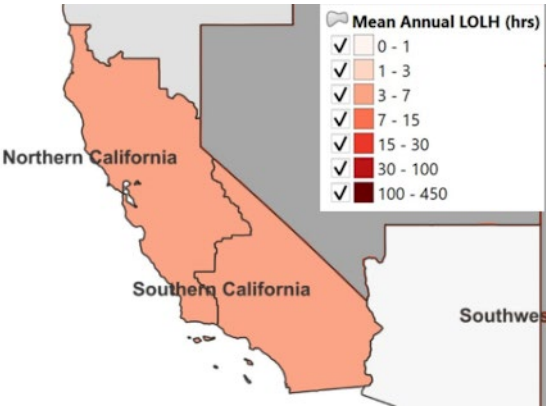
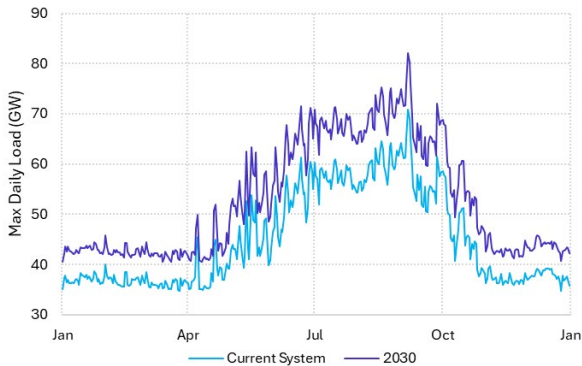


Table 14. Summary of CAISO+ Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	-	6.8	-	-
Normalized Unserved Energy (%)	-	0.0062	-	-
Unserved Load (MWh)	-	23,488	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	-	21	-	-
Normalized Unserved Load (%)	-	0.0195	-	-
Unserved Load (MWh)	-	73,462	-	-
Max Unserved Load (MW)	-	12,391	-	-

Load Assumptions

CAISO+’s peak load was roughly 79 GW in the current system model and projected to increase to roughly 82 GW by 2030. Approximately 2 GW of this relates to new AI/DCs being installed (4% of U.S. total).



Subregion	2024	2030
CALI-N	29,366	34,066
CALI-S	41,986	48,666
Total	70,815	82,146

Figure 22. CAISO+ Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 117 GW. In 2030, 14 GW of new capacity was added leading to 131 GW of capacity in the No Plant Closures case. In the Plant Closures case, 8 GW of capacity was retired such that net closures in the Plant Closures case were +6 GW, or 123 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
CALI-N	47,059	48,897	52,501
CALI-S	69,866	74,041	78,308
Total	116,925	122,938	130,809

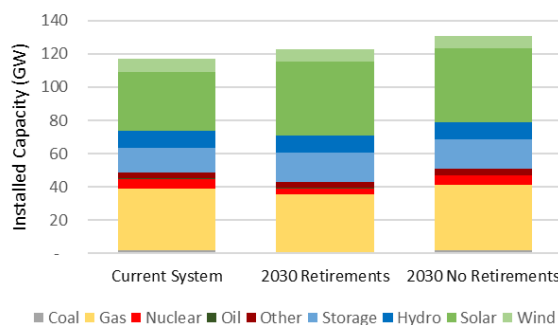


Figure 23. CAISO+ Generation Capacity by Technology and Scenario

CAISO+'s generation mix was comprised primarily of natural gas, solar, storage, and hydro. In 2024, natural gas comprised 32% of nameplate, solar comprised 31%, storage 13%, and hydro 9%. In 2030, most retirements come from coal, natural gas, and nuclear while additions occur for solar and storage. The model assumed 10 GW of rooftop solar and less than 1 GW of demand response.

Table 15. Nameplate Capacity by CAISO+ Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	1,816	37,434	5,582	185	3,594	14,670	10,211	35,661	7,773	116,925
CALI-N	0	12,942	5,582	165	1,872	4,639	8,727	11,759	1,373	47,059
CALI-S	1,816	24,492	0	20	1,722	10,031	1,483	23,902	6,400	69,866
Additions	0	2,126	0	0	92	3,161	0	8,507	0	13,885
CALI-N	0	735	0	0	44	757	0	3,906	0	5,442
CALI-S	0	1,391	0	0	48	2,404	0	4,600	0	8,442
Closures	(1,800)	(3,771)	(2,300)	0	0	0	0	0	0	(7,871)
CALI-N	0	(1,304)	(2,300)	0	0	0	0	0	0	(3,604)
CALI-S	(1,800)	(2,467)	0	0	0	0	0	0	0	(4,267)

2.8 West Non-CAISO

In both the current system and No Plant Closures cases, the West Non-CAISO region maintained adequacy on average. In the Plant Closures case, the region's reliability declined, with annual LOLH increasing and peak shortfalls in the worst year affecting up to 20% of hourly load in some subregions. While overall NUSE normalized unserved energy remained just above the 0.002% threshold, specific areas, especially those with limited local resources and constrained transmission, exceeded acceptable risk levels. These reliability gaps were primarily driven by increasing reliance on variable energy resources without sufficient firm generation.

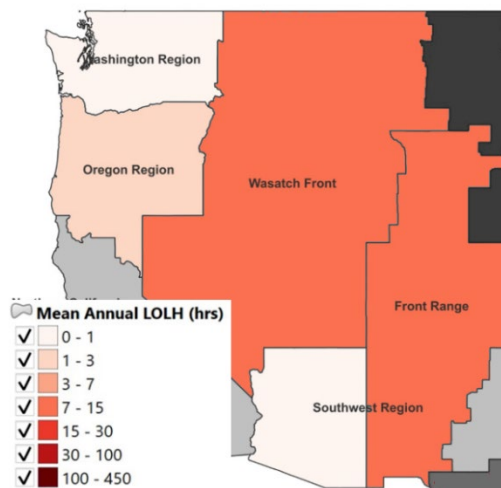
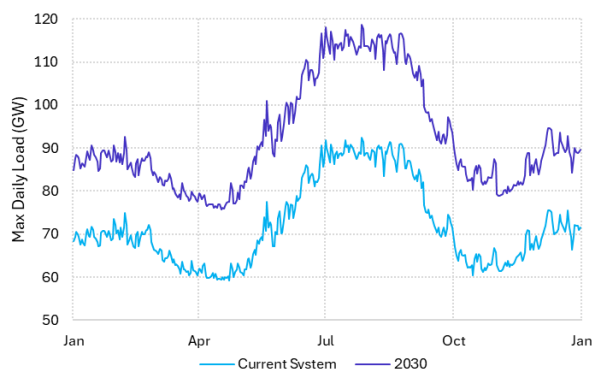


Table 16. Summary of West Non-CAISO Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	-	17.8	-	-
Normalized Unserved Energy (%)	-	0.0032	-	-
Unserved Load (MWh)	-	21,785	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	-	47	-	-
Normalized Unserved Load (%)	-	0.0098	-	-
Unserved Load (MWh)	-	66,248	-	-
Max Unserved Load (MW)	-	5,071	-	-

Load Assumptions

West Non-CAISO's peak load was roughly 92 GW in the current system model and projected to increase to roughly 119 GW by 2030. Approximately 12 GW of this relates to new AI/DCs being installed (24% of U.S. total).



Subregion	2024	2030
WASHINGTON	20,756	23,187
OREGON	11,337	16,080
SOUTHWEST	23,388	30,169
WASATCH	27,161	35,440
FRONT R	20,119	24,996
Total	92,448	118,657

Figure 24. West Non-CAISO Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was 178 GW. In 2030, 29 GW of new capacity was added leading to 207 GW of capacity in the No Plant Closures case. In the Plant Closures case, 13 GW of capacity was retired such that net generation change in the Plant Closures case was 16 GW, or 193 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
WASHINGTON	35,207	36,588	37,573
OREGON	19,068	21,689	22,081
SOUTHWEST	42,335	47,022	49,158
WASATCH	42,746	45,175	50,251
FRONT R	38,572	43,011	47,844
Total	177,929	193,485	206,908

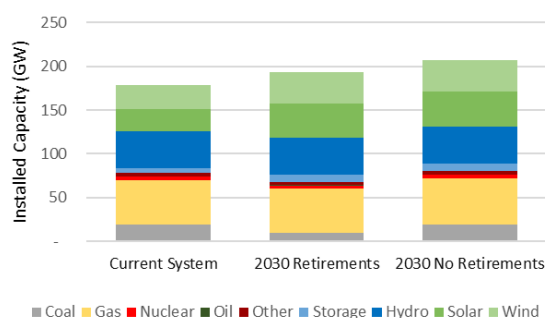


Figure 25. West Non-CAISO Generation Capacity by Technology and Scenario

West Non-CAISO's generation mix was comprised primarily of natural gas, hydro, wind, solar, and coal. In 2024, natural gas comprised 28% of nameplate, hydro comprised 24%, wind 15%, solar 13%, and coal 11%. In 2030, most retirements come from coal and natural gas while additions occur for solar, wind, storage, and natural gas. The model assumed 6 GW of rooftop solar and over 1 GW of demand response.

Table 17. Nameplate Capacity by West Non-CAISO Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	19,850	49,969	3,820	644	4,114	5,104	42,476	24,652	27,298	177,929
WASHINGTON	560	3,919	1,096	17	595	489	24,402	1,438	2,690	35,207
OREGON	0	3,915	0	6	456	482	8,253	2,517	3,440	19,068
SOUTHWEST	4,842	17,985	2,724	323	1,316	2,349	1,019	8,093	3,685	42,335
WASATCH	7,033	14,061	0	87	1,433	1,194	7,587	7,299	4,052	42,746
FRONT R	7,415	10,089	0	211	314	590	1,215	5,306	13,432	38,572
Additions	0	2,320	0	1	8	2,932	0	14,759	8,959	28,979
WASHINGTON	0	246	0	0	0	109	0	1,059	952	2,366
OREGON	0	246	0	0	0	150	0	1,399	1,218	3,013
SOUTHWEST	0	309	0	0	0	2,338	0	3,578	599	6,823
WASATCH	0	884	0	0	7	233	0	4,946	1,435	7,505
FRONT R	0	634	0	0	0	102	0	3,779	4,756	9,271
Closures	(9,673)	(2,540)	0	(6)	(311)	(170)	(627)	0	(95)	(13,422)
WASHINGTON	(317)	(195)	0	(0)	(66)	(28)	(369)	0	(11)	(986)
OREGON	0	(195)	0	(0)	(58)	0	(125)	0	(14)	(392)
SOUTHWEST	(1,185)	(951)	0	0	0	0	0	0	0	(2,136)
WASATCH	(3,978)	(699)	0	(2)	(178)	(89)	(115)	0	(16)	(5,077)
FRONT R	(4,194)	(501)	0	(4)	(8)	(53)	(18)	0	(54)	(4,832)

2.9 ERCOT

In the current system model, ERCOT exceeded reliability thresholds, with 3.8 annual Loss of Load Hours and a NUSE of 0.0032%, indicating stress even before future retirements and load growth. In the No Plant Closures case, conditions worsened as average LOLH rose to 20 hours per year and the worst-case year reached 101 hours, driven by data center growth and limited dispatchable additions. The Plant Closures case intensified these risks, with average annual LOLH rising to 45 hours per year and unserved load reaching 0.066%. Peak shortfalls reached 27% of demand, with outages concentrated in winter when generation is most vulnerable. To meet reliability targets, ERCOT would require 10,500 MW of additional perfect capacity by 2030.

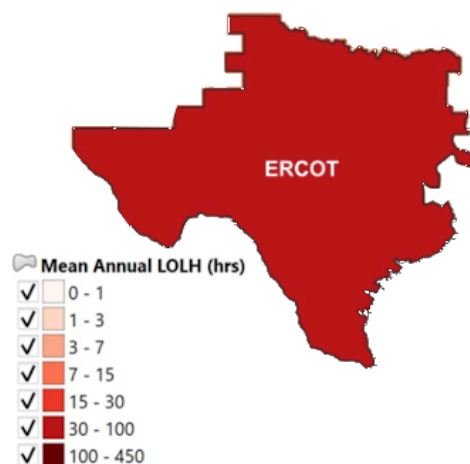


Table 18. Summary of ERCOT Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	3.8	45.0	20.3	1.0
Normalized Unserved Energy (%)	0.0032	0.0658	0.0284	0.0008
Unserved Load (MWh)	15,378	397,352	171,493	4,899
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	30	149	101	12
Normalized Unserved Load (%)	0.0286	0.02895	0.01820	0.0098
Unserved Load (MWh)	136,309	1,741,003	1,093,560	58,787
Max Unserved Load (MW)	10,115	27,156	23,105	8,202

Load Assumptions

ERCOT's peak load was roughly 90 GW in the current system model and projected to increase to roughly 105 GW by 2030. Approximately 8 GW of this relates to new data centers being installed (62% of U.S. total).

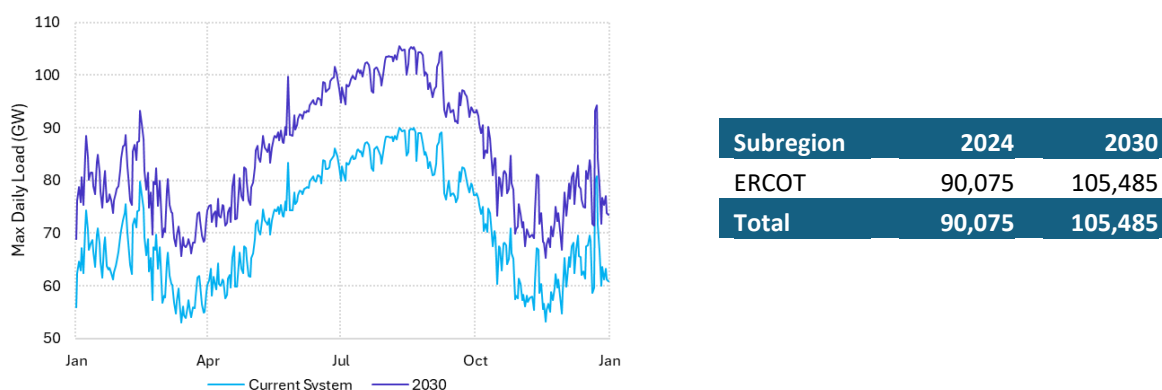


Figure 26. ERCOT Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was 157 GW. In 2030, 55 GW of new capacity was added leading to 213 GW of capacity in the No Plant Closures case. In the Plant Closures case, 4 GW of capacity was retired such that net generation change in the Plant Closures case was +51 GW, or 208 GW of overall nameplate capacity on the system.

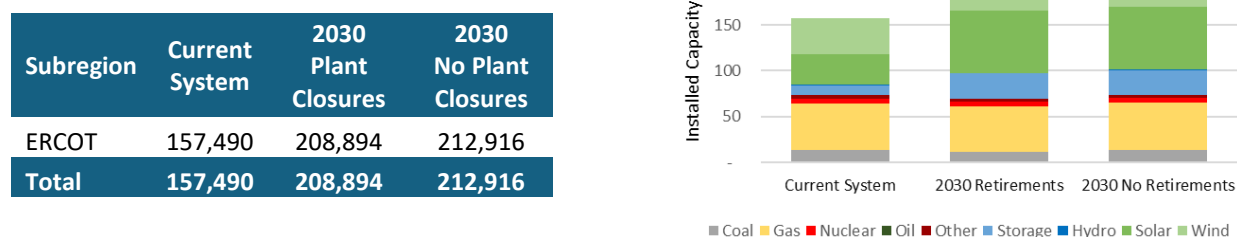


Figure 27. ERCOT Generation Capacity by Technology and Scenario

ERCOT's generation mix was comprised primarily of natural gas, wind, and solar. In 2024, natural gas comprised 32% of nameplate, wind comprised 25%, and solar 22%. In 2030, most retirements come from coal and natural gas while additions occur for solar, storage, and wind. The model assumed 2.5 GW of rooftop solar and 3.5 GW of demand response.

Table 19. Nameplate Capacity for ERCOT and by Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	13,568	50,889	4,973	10	3,627	10,720	583	33,589	39,532	157,490
ERCOT	13,568	50,889	4,973	10	3,627	10,720	583	33,589	39,532	157,490
Additions	0	569	0	0	0	16,538	0	34,681	3,638	55,426
ERCOT	0	569	0	0	0	16,538	0	34,681	3,638	55,426
Closures	(2,000)	(2,022)	0	0	0	0	0	0	0	(4,022)
ERCOT	(2,000)	(2,022)	0	0	0	0	0	0	0	(4,022)

Appendix A - Generation Calibration and Forecast

The study team started with the grid model from the NERC ITCS, which was published in 2024 with reference to NERC 2023 LTRA capacity.²⁷ This zonal ITCS model serves as the starting point for the network topology (covering 23 U.S. regions), transmission capacity between zones, and general modeling assumptions. The resource mix and retirements in the ITCS model were updated for this study to reflect the various 2030 scenarios discussed previously. Prior to developing the 2030 scenarios, the study team also updated the 2024 ITCS model to ensure consistency in the current model assumptions.

2024 Resource Mix

Because there were noted changes in assumed capacity additions between the 2023 and 2024 LTRAs²⁸, the ITCS model was updated with the 2024 LTRA data, provided directly by NERC to the study team. The 2024 LTRA dataset, reported at the NERC assessment area level—which is more aggregated in some areas than the ITCS regional structure (covering 13 U.S. regions; see Figure A.1)—includes both existing resource capacities²⁹ and Tier 1, 2, and 3 planned additions for each year from 2024 to 2033. As explained below, to incorporate this data into the ITCS model, a mapping process was developed to disaggregate generation capacities from the NERC assessment areas to the more granular ITCS regions by technology type. To preserve the daily or monthly adjustments to generator availability for certain categories (wind, solar, hybrid, hydropower, batteries, and other) by using the ITCS methods, the nameplate LTRA capacity was used. For all other categories (mostly thermal generators), summer and winter on-peak capacity contributions were used.

27. NERC, “Interregional Transfer Capability Study (ITCS).”
https://www.nerc.com/pa/RAPA/Documents/ITCS_Final_Report.pdf.

28. NERC, “2024 Long-Term Reliability Assessment,” December, 2024, 24.
https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

29. Capacities are reported for both winter and summer seasonal ratings, along with nameplate values.

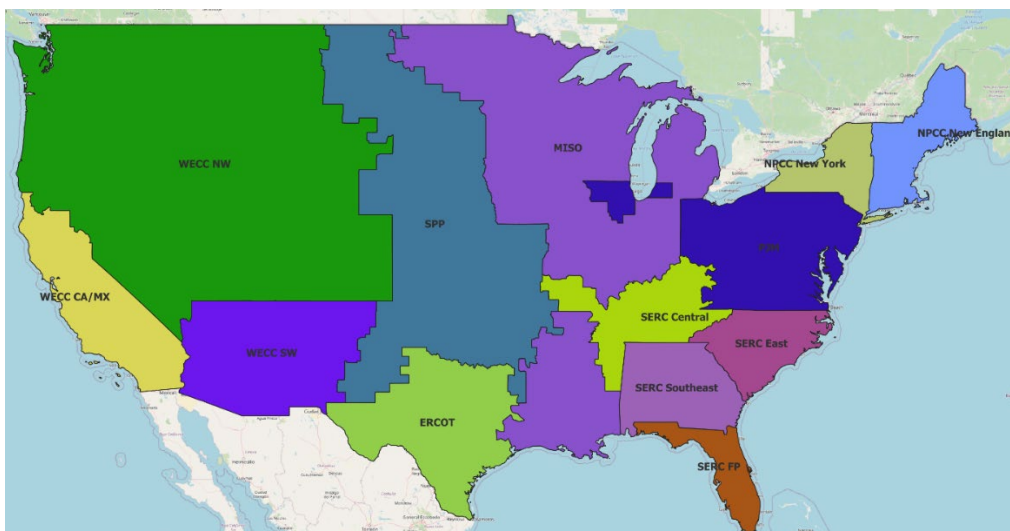


Figure A.1. NERC assessment areas.

To disaggregate generation capacity from the NERC assessment areas to the ITCS regions, EIA 860 plant-level data were used to tabulate the generation capacity for each ITCS region and NERC assessment area. The geographical boundaries for the NERC assessment areas and the ITCS regions were constructed based on ReEDS zones.³⁰ Disaggregation fractions were then calculated by technology type using the combined existing capacity and planned additions through 2030 from EIA 860 data as of December 2024. Specifically, to compute each fraction, an ITCS region's total (existing plus planned) capacity was divided by the corresponding total capacity across all ITCS regions within the same mapped NERC assessment area and fuel type group:

$$Fraction_{rf} = \frac{Capacity_{rf}}{\sum_{r' \in ITCS(R)} Capacity_{r'f}} \quad (Equation.1)$$

Where $Capacity_{rf}$ is the capacity of fuel type f in ITCS region r and $ITCS(R)$ is the set of all ITCS regions mapped to the same NERC assessment area R . The denominator is the total capacity of that fuel type across all ITCS regions mapped to R .

Note that in cases where NERC assessment areas align one-to-one with ITCS regions, no mapping was required. Table A.1 summarizes which areas exhibited a direct one-to-one matching and which required disaggregation (1-to-many) or aggregation (many-to-one) to align with the ITCS regional structure.

An exception to this general approach is the case of the Front Range ITCS region, which geographically spans across two NERC assessment areas—WECC-NW and WECC-SW—resulting in two-to-one mapping. For this case, a separate allocation method was used: Plant-level data from EIA 860 were analyzed to determine the proportion of Front Range capacity located in each NERC area. These proportions were then used to derive custom weighting factors for allocating capacities from both WECC-NW and WECC-SW into the Front Range region.

30. NREL, “Regional Energy Development System,” <https://www.nrel.gov/analysis/reeds/>.

Table A.1. Mapping of NERC assessment areas to ITCS regions.

NERC Area	ITCS Region	Match
ERCOT	ERCOT	1 to 1
NPCC-New England	NPCC-New England	1 to 1
NPCC-New York	NPCC-New York	1 to 1
SERC-C	SERC-C	1 to 1
SERC-E	SERC-E	1 to 1
SERC-FP	SERC-FP	1 to 1
SERC-SE	SERC-SE	1 to 1
WECC-SW	Southwest Region	1 to 1
MISO	MISO Central	1 to 4
MISO	MISO East	
MISO	MISO South	
MISO	MISO West	
SPP	SPP North	1 to 2
SPP	SPP South	
WECC-CAMX	Southern California	1 to 2
WECC-CAMX	Northern California	
WECC-NW	Oregon Region	1 to 3
WECC-NW	Washington Region	
WECC-NW	Wasatch Front	
WECC-NW	Front Range	2 to 1
WECC-SW	Front Range	

Table A.2 and Figure A.2 show the same combined capacities by ITCS region and NERC planning region, respectively.

Table A.2. Existing and Tier 1 capacities by NERC assessment area (in MW) in 2024.

2024 Existing + Tier 1		Coal	NG	Nuclear	Oil	Biomass	Geo	Other	Pumped Storage	Battery	Hydro	Solar	Wind	DR	DGPV	Total
EAST	Total	143,035	330,342	82,793	26,771	3,624	-	991	19,607	3,298	28,980	72,757	94,364	25,753	24,367	856,682
	ISONE Total	541	15,494	3,331	5,710	818	-	233	1,571	57	1,911	3,386	2,553	661	3,713	39,979
	MISO Total	37,914	64,194	11,127	2,867	613	-	329	4,396	1,031	2,533	29,777	41,715	7,775	3,049	207,319
	MISO-W	12,651	13,608	2,753	1,491	244	-	2	-	200	777	7,368	29,411	2,367	741	71,612
	MISO-C	15,050	10,307	2,169	494	32	-	152	773	499	769	10,587	7,350	2,026	1,774	51,982
	MISO-S	5,493	31,052	5,100	589	243	-	117	49	5	845	8,024	596	2,109	291	54,511
	MISO-E	4,720	9,227	1,105	292	94	-	57	3,574	327	143	3,799	4,359	1,273	243	29,213
	NYISO Total	-	22,937	3,330	2,631	334	-	-	1,400	60	4,915	1,039	2,706	860	5,710	45,924
	PJM Total	39,915	84,381	32,535	9,875	851	-	-	5,062	338	3,071	10,892	11,718	7,397	8,603	214,638
	PJM-W	34,917	39,056	16,557	1,933	112	-	-	234	149	1,252	5,780	10,065	3,814	599	114,467
	PJM-S	2,391	15,038	5,288	3,985	479	-	-	2,958	127	1,070	3,932	360	1,824	2,498	39,951
	PJM-E	2,608	30,287	10,690	3,956	260	-	-	1,870	62	749	1,180	1,294	1,759	5,506	60,221
	SERC Total	45,747	113,334	31,702	4,063	989	-	83	6,701	768	11,425	26,959	982	7,707	3,221	253,680
	SERC-C	13,348	20,127	8,280	148	36	-	-	1,784	100	4,995	2,308	982	1,851	20	53,978
	SERC-SE	13,275	29,866	8,018	915	424	-	-	1,548	115	3,260	7,267	-	2,069	317	67,073
	SERC-FL	4,346	47,002	3,502	1,957	310	-	83	-	538	-	10,121	-	2,804	2,051	72,714
	SERC-E	14,777	16,340	11,902	1,044	219	-	-	3,369	15	3,170	7,263	-	983	833	59,914
	SPP Total	18,919	30,003	769	1,626	20	-	345	477	1,044	5,123	703	34,689	1,353	71	95,142
	SPP-N	5,089	3,467	304	504	1	-	185	-	8	3,041	84	7,041	333	7	20,065
	SPP-S	13,829	26,536	465	1,121	19	-	160	477	1,037	2,082	619	27,649	1,020	64	75,078
ERCOT	Total	13,568	50,889	4,973	10	163	-	-	-	10,720	583	31,058	39,532	3,464	2,531	157,490
ERCOT	Total	13,568	50,889	4,973	10	163	-	-	-	10,720	583	31,058	39,532	3,464	2,531	157,490
WEST	Total	21,666	87,403	9,403	829	1,565	4,093	106	4,536	15,238	52,687	44,042	35,071	1,944	16,271	294,854
	CAISO+ Total	1,816	37,434	5,582	185	726	2,004	35	3,514	11,156	10,211	25,614	7,773	829	10,047	116,925
	CALI-N	-	12,942	5,582	165	465	1,049	9	1,967	2,672	8,727	6,723	1,373	349	5,036	47,059
	CALI-S	1,816	24,492	-	20	261	955	26	1,547	8,484	1,483	18,891	6,400	480	5,011	69,866
	Non-CA WECC Total	19,850	49,969	3,820	644	839	2,089	71	1,022	4,082	42,476	18,428	27,298	1,115	6,224	177,929
	WA	560	3,919	1,096	17	352	-	-	140	350	24,402	1,052	2,690	243	386	35,207
	OR	-	3,915	-	6	293	21	-	-	482	8,253	2,145	3,440	141	372	19,068
	SOUTHWEST	4,842	17,985	2,724	323	102	1,047	-	176	2,173	1,019	5,641	3,685	168	2,452	42,335
	WASATCH	7,033	14,061	-	87	56	1,011	61	444	750	7,587	5,625	4,052	305	1,674	42,746
	FRONT R	7,415	10,089	-	211	36	10	10	262	328	1,215	3,966	13,432	258	1,340	38,572
Total		178,268	468,635	97,169	27,610	5,353	4,093	1,096	24,144	29,256	82,249	147,856	168,966	31,161	43,169	1,309,026

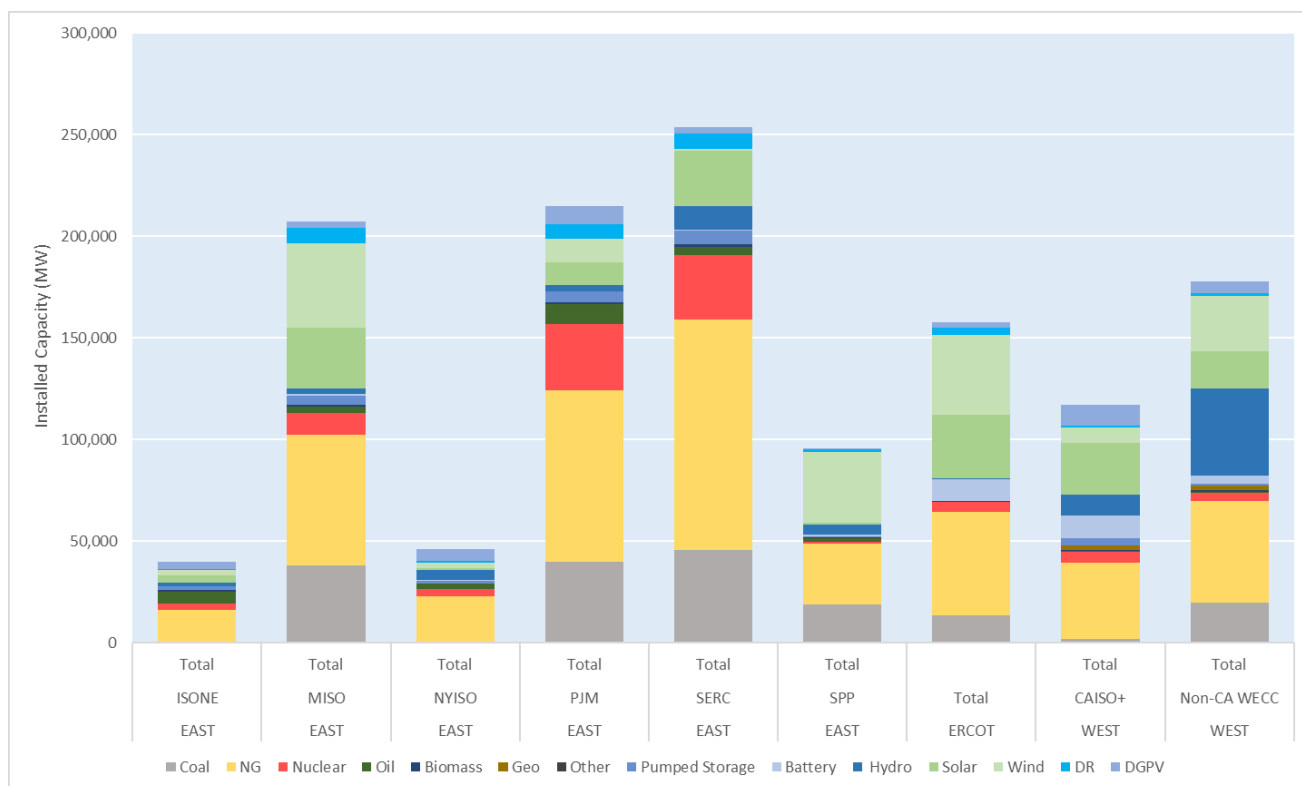


Figure A.2. Existing and Tier 1 capacities by NERC assessment area in 2024.

Forecasting 2030 Resource Mixes

To develop the 2030 ITCS generation portfolio, the study team added new capacity builds and removed planned retirements.

- (i) *Tier 1*: Assumes that only projects considered very mature in the development pipeline—such as those with signed interconnection agreements—will be built. This results in minimal capacity additions beyond 2026. The data are based on projects designated as Tier 1 in the 2024 LTRA data for the year 2030.

Retirements

To project which units will retire by 2030, the study team primarily used the LTRA 2024 data and cross-checked it with EIA data. The assessment areas were disaggregated to ITCS zones based on the ratios of projected retirements in EIA 860 data. The three scenarios modeled are as follows:

- (i) *Announced*: Assumes that in addition to confirmed retirements, generators that have publicly announced retirement plans but have not formally notified system operators have also begun the retirement process. This is based on data from the 2024 LTRA, which were collected by the NERC team from sources like news announcements, public disclosures, etc.

- (ii) *None*: Assumes that there are no retirements between 2024 and 2030 for comparison. Delaying or canceling some near-term retirements may not be feasible, but this case can help determine how much retirements contribute to resource adequacy challenges in regions where rapid AI and data center growth is expected.

Generation Stack for Each Scenario

Finally, when summing all potential future changes, the team arrived at a generation stack for each of the various scenarios to be studied. The first figure provides a visual comparison of all the cases, which vary from 1,309 GW to 1,519 GW total generation capacity for the entire continental United States, to enable the exploration of a range of potential generation futures. The tables below provide breakdowns by ITCS region and by resource type.

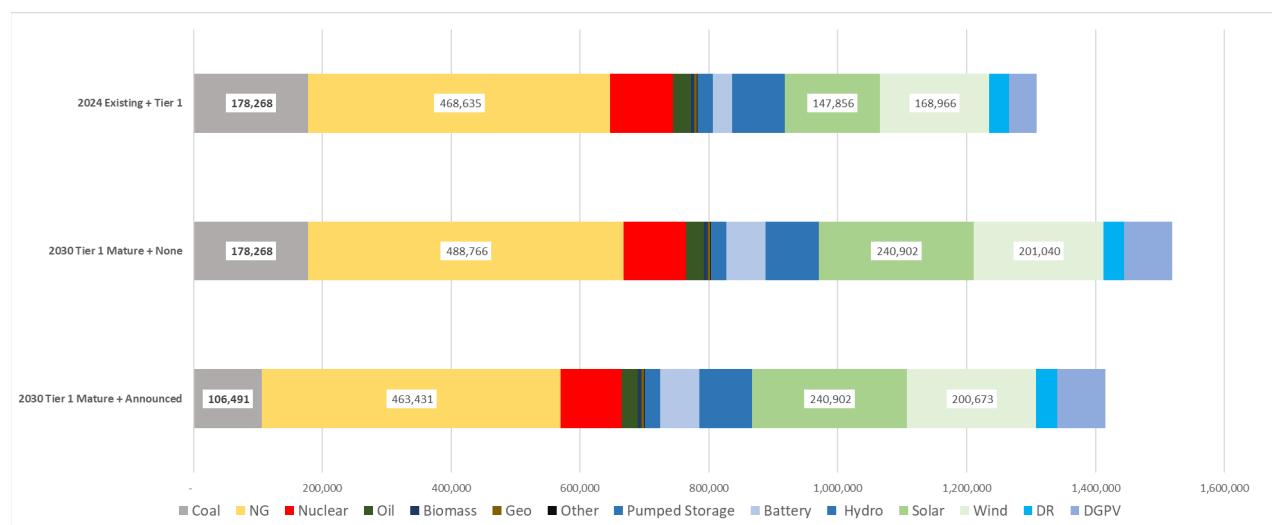


Figure A.9. Comparison of 2030 generation stacks for the various scenarios.

Table A.4. 2030 generation stack for Tier 1 mature + announced retirements.

2030 Tier 1 Mature + Announced		Coal	NG	Nuclear	Oil	Biomass	Geo	Other	Pumped Storage	Battery	Hydro	Solar	Wind	DR	DGPV	Total
EAST	Total	84,730	328,457	82,793	24,272	3,473	-	991	19,591	12,415	28,897	126,849	113,568	26,837	36,768	889,641
	ISONE Total	7	13,708	3,331	5,687	741	-	233	1,571	1,664	1,911	3,676	4,048	661	5,606	42,845
	MISO Total	13,001	60,132	11,127	2,873	473	-	329	4,380	2,960	2,450	44,132	43,369	7,775	3,049	196,049
	MISO-W	4,338	12,747	2,753	1,494	188	-	2	-	574	751	10,920	30,577	2,367	741	67,453
	MISO-C	5,161	9,655	2,169	495	25	-	152	770	1,433	743	15,690	7,642	2,026	1,774	47,735
	MISO-S	1,883	29,087	5,100	591	187	-	117	49	14	817	11,892	619	2,109	291	52,756
	MISO-E	1,619	8,643	1,105	293	72	-	57	3,561	938	138	5,630	4,531	1,273	243	28,105
	NYISO Total	-	21,907	3,330	2,628	334	-	-	1,400	60	4,915	1,159	4,608	860	9,194	50,396
	PJM Total	26,662	87,228	32,535	8,117	917	-	-	5,062	2,276	3,071	33,530	18,807	7,638	10,955	236,798
	PJM-W	23,323	40,373	16,557	1,589	120	-	-	234	1,004	1,252	17,793	16,153	3,939	762	123,100
	PJM-S	1,597	15,546	5,288	3,276	516	-	-	2,958	853	1,070	12,105	577	1,883	3,181	48,850
	PJM-E	1,742	31,309	10,690	3,252	280	-	-	1,870	419	749	3,632	2,076	1,816	7,012	64,848
	SERC Total	31,672	116,117	31,702	3,391	989	-	83	6,701	3,021	11,425	38,360	982	8,088	7,893	260,423
	SERC-C	8,883	23,777	8,280	148	36	-	-	1,784	180	4,995	3,070	982	1,851	29	54,014
	SERC-SE	10,321	28,127	8,018	899	424	-	-	1,548	618	3,260	9,024	-	2,213	317	64,768
	SERC-FL	2,851	47,092	3,502	1,477	310	-	83	-	2,208	-	16,717	-	3,022	5,865	83,127
	SERC-E	9,617	17,122	11,902	868	219	-	-	3,369	15	3,170	9,549	-	1,002	1,682	58,513
	SPP Total	13,389	29,365	769	1,576	20	-	345	477	2,434	5,123	5,991	41,755	1,815	71	103,130
	SPP-N	3,602	3,394	304	489	1	-	185	-	18	3,041	717	8,475	447	7	20,679
	SPP-S	9,787	25,971	465	1,087	19	-	160	477	2,416	2,082	5,274	33,280	1,368	64	82,451
ERCOT	Total	11,568	49,436	4,973	10	163	-	-	-	27,258	583	62,406	43,169	3,464	5,864	208,894
	ERCOT Total	11,568	49,436	4,973	10	163	-	-	-	27,258	583	62,406	43,169	3,464	5,864	208,894
WEST	Total	10,193	85,538	7,103	823	1,427	3,983	106	4,366	21,330	52,060	51,648	43,935	1,981	31,931	316,424
	CAISO+ Total	16	35,789	3,282	185	726	2,059	35	3,514	14,316	10,211	27,112	7,773	866	17,055	122,938
	CALI-N	-	12,373	3,282	165	465	1,078	9	1,967	3,429	8,727	7,116	1,373	364	8,549	48,897
	CALI-S	16	23,416	-	20	261	982	26	1,547	10,887	1,483	19,996	6,400	501	8,506	74,041
	Non-CA WECC Total	10,177	49,749	3,820	639	701	1,924	71	852	7,014	41,849	24,536	36,162	1,115	14,876	193,485
	WA	243	3,971	1,096	16	286	-	-	111	459	24,033	1,404	3,631	243	1,092	36,588
	OR	-	3,967	-	6	238	18	-	-	632	8,128	2,865	4,644	141	1,051	21,689
	SOUTHWEST	3,657	17,343	2,724	323	102	1,047	-	176	4,511	1,019	7,460	4,284	168	4,211	47,022
	WASATCH	3,055	14,247	-	86	45	850	61	355	983	7,472	7,512	5,470	305	4,733	45,175
	FRONT R	3,221	10,222	-	208	30	8	10	209	430	1,197	5,296	18,133	258	3,789	43,011
Total		106,491	463,431	94,869	25,106	5,063	3,983	1,096	23,958	61,003	81,539	240,902	200,673	32,282	74,563	1,414,959

Table A.5. 2030 generation stack for Tier 1 mature + no retirements.

2030 Tier 1 Mature + No Retirements			Coal	NG	Nuclear	Oil	Biomass	Geo	Other	Pumped Storage	Battery	Hydro	Solar	Wind	DR	DGPV	Total
EAST	Total		143,035	345,459	82,793	27,336	3,701	-	991	19,607	12,415	28,980	126,849	113,840	26,837	36,768	968,610
	ISONE	Total	541	15,584	3,331	5,891	818	-	233	1,571	1,664	1,911	3,676	4,048	661	5,606	45,534
	MISO	Total	37,914	66,729	11,127	3,197	613	-	329	4,396	2,960	2,533	44,132	43,641	7,775	3,049	228,393
		MISO-W	12,651	14,145	2,753	1,662	244	-	2	-	574	777	10,920	30,768	2,367	741	77,605
		MISO-C	15,050	10,714	2,169	551	32	-	152	773	1,433	769	15,690	7,690	2,026	1,774	58,823
		MISO-S	5,493	32,278	5,100	657	243	-	117	49	14	845	11,892	623	2,109	291	59,710
		MISO-E	4,720	9,592	1,105	326	94	-	57	3,574	938	143	5,630	4,560	1,273	243	32,255
	NYISO	Total	-	22,937	3,330	2,646	334	-	-	1,400	60	4,915	1,159	4,608	860	9,194	51,444
	PJM	Total	39,915	88,880	32,535	9,907	928	-	-	5,062	2,276	3,071	33,530	18,807	7,638	10,955	253,504
		PJM-W	34,917	41,138	16,557	1,939	122	-	-	234	1,004	1,252	17,793	16,153	3,939	762	135,810
		PJM-S	2,391	15,840	5,288	3,998	522	-	-	2,958	853	1,070	12,105	577	1,883	3,181	50,667
		PJM-E	2,608	31,902	10,690	3,969	284	-	-	1,870	419	749	3,632	2,076	1,816	7,012	67,027
	SERC	Total	45,747	120,232	31,702	4,063	989	-	83	6,701	3,021	11,425	38,360	982	8,088	7,893	279,285
		SERC-C	13,348	24,958	8,280	148	36	-	-	1,784	180	4,995	3,070	982	1,851	29	59,660
		SERC-SE	13,275	29,866	8,018	915	424	-	-	1,548	618	3,260	9,024	-	2,213	317	69,478
		SERC-FL	4,346	48,163	3,502	1,957	310	-	83	-	2,208	-	16,717	-	3,022	5,865	86,173
		SERC-E	14,777	17,246	11,902	1,044	219	-	-	3,369	15	3,170	9,549	-	1,002	1,682	63,973
	SPP	Total	18,919	31,098	769	1,632	20	-	345	477	2,434	5,123	5,991	41,755	1,815	71	110,449
		SPP-N	5,089	3,594	304	506	1	-	185	-	18	3,041	717	8,475	447	7	22,385
		SPP-S	13,829	27,504	465	1,126	19	-	160	477	2,416	2,082	5,274	33,280	1,368	64	88,064
ERCOT	Total		13,568	51,458	4,973	10	163	-	-	-	27,258	583	62,406	43,169	3,464	5,864	212,916
	ERCOT	Total	13,568	51,458	4,973	10	163	-	-	-	27,258	583	62,406	43,169	3,464	5,864	212,916
WEST	Total		21,666	91,849	9,403	829	1,565	4,156	106	4,536	21,330	52,687	51,648	44,030	1,981	31,931	337,717
	CAISO+	Total	1,816	39,560	5,582	185	726	2,059	35	3,514	14,316	10,211	27,112	7,773	866	17,055	130,809
		CALI-N	-	13,677	5,582	165	465	1,078	9	1,967	3,429	8,727	7,116	1,373	364	8,549	52,501
		CALI-S	1,816	25,883	-	20	261	982	26	1,547	10,887	1,483	19,996	6,400	501	8,506	78,308
	Non-CA WECC	Total	19,850	52,289	3,820	645	839	2,097	71	1,022	7,014	42,476	24,536	36,257	1,115	14,876	206,908
		WA	560	4,166	1,096	17	352	-	-	140	459	24,402	1,404	3,642	243	1,092	37,573
		OR	-	4,161	-	6	293	22	-	-	632	8,253	2,865	4,658	141	1,051	22,081
		SOUTHWEST	4,842	18,294	2,724	323	102	1,047	-	176	4,511	1,019	7,460	4,284	168	4,211	49,158
		WASATCH	7,033	14,945	-	88	56	1,018	61	444	983	7,587	7,512	5,486	305	4,733	50,251
		FRONT R	7,415	10,723	-	212	36	10	10	262	430	1,215	5,296	18,187	258	3,789	47,844
Total			178,268	488,766	97,169	28,175	5,429	4,156	1,096	24,144	61,003	82,249	240,902	201,040	32,282	74,563	1,519,243

Appendix B - Representing Canadian Transfer Limits

Introduction

The reliability and stability of cross-border electricity interconnections between the United States and Canada are critical to ensuring continuous power delivery amid evolving demands and variable supply conditions. In recent years, increased integration of wind and solar generation, coupled with extreme weather events, has introduced significant uncertainties in regional power flows.

This report describes the development and implementation of a machine learning (ML)-based model designed to project the maximum daily energy transfer (MaxFlow) across major United States–Canada interfaces, such as BPA–BC Hydro and NYISO–Ontario. Leveraging 15 years of high-resolution load and generation data, summarizing it into key daily statistics, and training a robust eXtreme Gradient Boosting (XGBoost) regressor can allow data-driven predictions to be captured with quantified uncertainty.

The project team provided percentile-based forecasts—25, 50, and 75 percent—to support both conservative and strategic planning. The conservative methodology (25 percent) was used for this report to ensure availability when needed.

The subsequent sections detail the methodology used for data processing and feature engineering, the architecture and training of the predictive model, and the validation metrics and feature importance analyses used. Future enhancements could include incorporating weather patterns, neighboring-region dynamics, and fuel-specific generation profiles to further strengthen predictive performance and support grid resilience.

Methodology

This section describes the ML approach used to build the MaxFlow prediction model.

Dataset Collection and Preparation

Data were collected for hourly and derived daily load and generation over a 15-year period (2010–2024), comprising 8,760 hourly observations annually. Hourly interconnection flow rates were collected for the same years across all major United States–Canada interfaces.^{1–17}

Underlying Hypothesis

The team hypothesized that the MaxFlow between interconnected regions is critically influenced by regional load and generation extrema (maximum and minimum) and their variability. These statistics reflect grid stress conditions, influencing interregional energy flow. Additionally, nonlinear interactions due to imbalances in adjacent regions further affect energy transfer dynamics.

Regression Model

The XGBoost regression model was chosen because of its ability to capture complex, nonlinear relationships, regularization capability to prevent overfitting, high speed and performance, fast convergence, built-in handling of missing data, and ease of confidence interval approximation.

XGBoost builds many small decision trees, one after another. Each new tree learns to correct the mistakes of the previous ensemble by focusing on which predictions had the greatest error. Instead of creating one large, complex tree, it combines many simpler trees—each making a modest adjustment—so that, together, they capture nonlinear patterns and interactions. Regularization (penalties for tree size and leaf adjustments) prevents overfitting, and a “learning rate” scales each tree’s contribution so that improvements are made gradually. The final prediction is simply the sum of all those small corrections.

Model Training, Validation, and Assessment

Figure B.1 shows the data analysis and prediction process, which ties together seven stages—from raw CSV loading through outlier filtering, feature engineering, projecting to 2030, rebuilding 2030 features, training an XGBoost model, and finally making and evaluating the 2030 flow forecasts with quantiles. Each stage feeds into the next, ensuring that the features used for training mirror exactly those that will be available for future (2030) predictions.

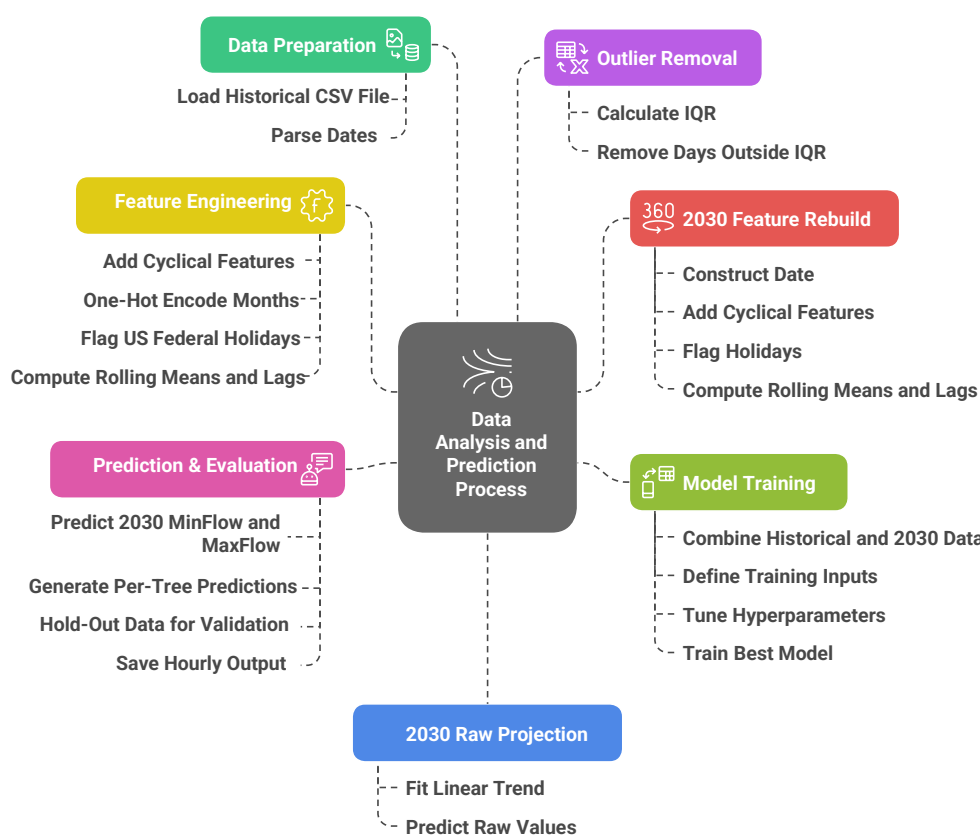


Figure B.1. Data analysis and prediction process.

Example Feature Importance for Predicting MaxFlow from Ontario to NYISO

The trained ML/XGBoost model can be used for predicting the desired year’s MaxFlow. In addition, feature importance analysis can be added to assess the contribution of each variable.

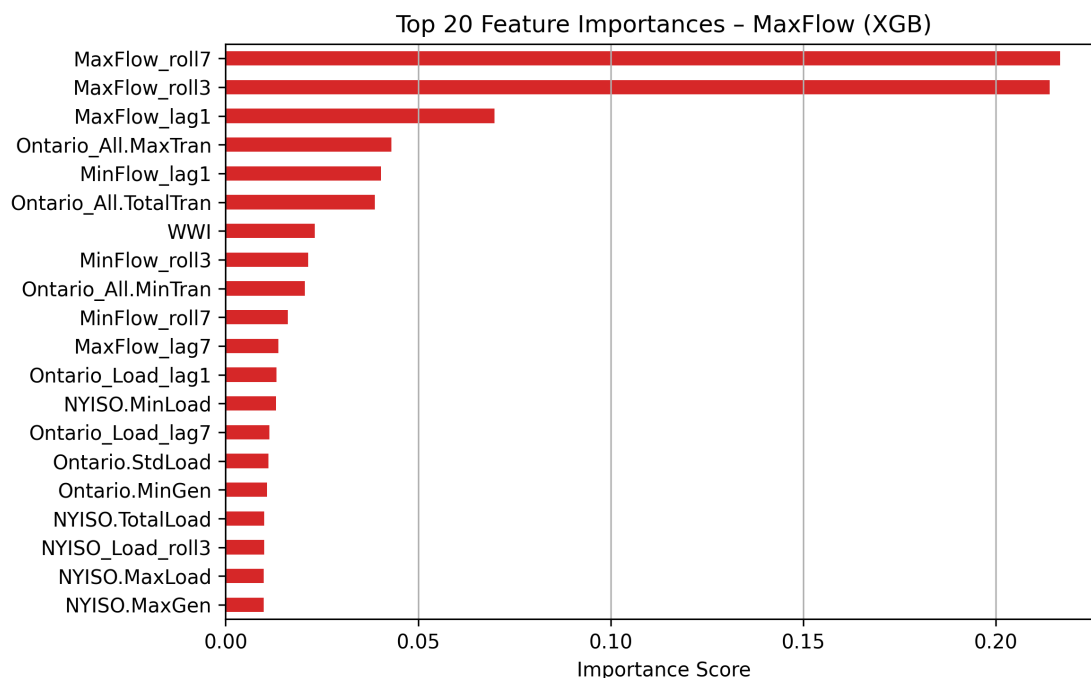


Figure B.2. Feature importance for predicting the hourly maximum energy transfer (MaxFlow) between NYISO and Ontario. XGB = eXtreme Gradient Boosting.

The feature importance plot shows that MaxFlow rolling/lagging features and Ontario_All.MaxTran are the dominant predictors of MaxFlow, meaning temporal patterns and Ontario's peak transfer capacity strongly influence interregional flow limits. Weather-related variables (WWI, e.g., temperature, humidity, etc.) and Ontario_All.TotalTran also rank highly. The 2030 MaxFlow prediction plot shows seasonal fluctuations, with higher values early and late in the year. The red shaded area represents a 95 percent confidence interval for the predictions.

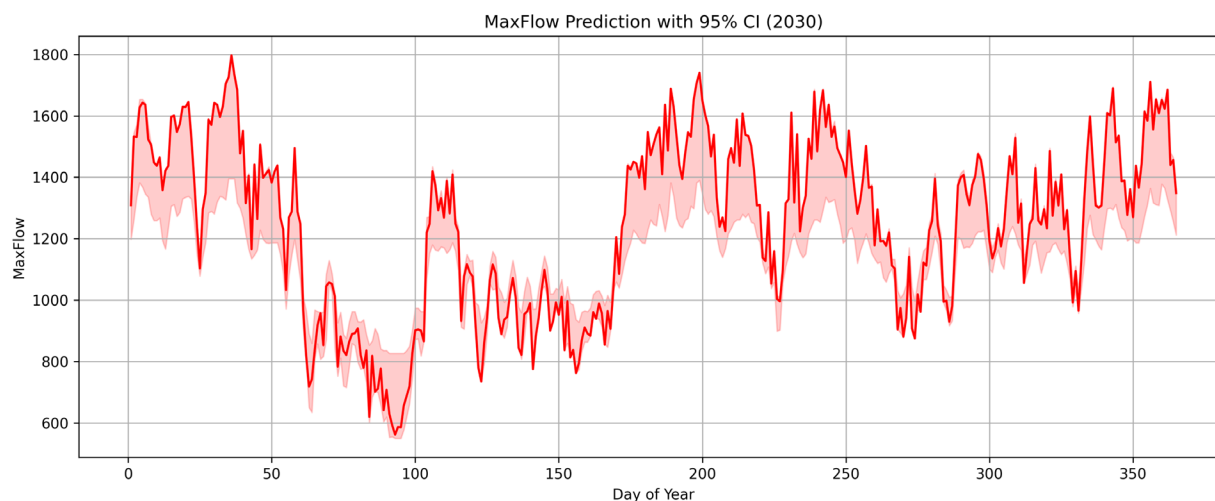


Figure B.3. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI).

Model Performance

Validating model performance on unseen data is essential to ensure the model’s reliability and generalizability. The following evaluation examines how well the XGBoost model predicts minimum energy transfer (MinFlow) and MaxFlow on the validation split, highlighting strengths and areas for improvement.

Rigorous performance evaluation is a fundamental step in any ML workflow. From quantifying error metrics (root mean square error and mean absolute error) and goodness-of-fit (R^2) on both training and validation splits, it is possible to identify overfitting, assess generalization, and guide model refinement. Table B.1 shows XGBoost model performance for the Ontario–NYISO transfer limit.

Table B.1. eXtreme Gradient Boosting model performance for the Ontario–NYISO transfer limit.

Metric	Value	Explanation
MinFlow RMSE (Train)	69.2528	Root mean square error (RMSE) on training data for minimum energy transfer (MinFlow)
MinFlow R^2 (Train)	0.9651	R^2 on training data for MinFlow (higher → better fit)
MinFlow RMSE (Validation)	163.6642	RMSE on held-out data for MinFlow
MinFlow R^2 (Validation)	0.8073	R^2 on held-out data for MinFlow (higher → better generalization)
MaxFlow RMSE (Train)	114.4234	RMSE on training data for maximum energy transfer (MaxFlow)
MaxFlow R^2 (Train)	0.8838	R^2 on training data for MaxFlow (higher → better fit)
MaxFlow RMSE (Validation)	144.9614	RMSE on held-out data for MaxFlow
MaxFlow R^2 (Validation)	0.8178	R^2 on held-out data for MaxFlow (higher → better generalization)

Overall, the XGBoost model delivers excellent in-sample as well as out-of-sample accuracy. Similar outputs are available for each transfer limit.

Maximum flow predictions: Ontario to New York

Ontario and NYISO are connected through multiple high-voltage interconnections, which collectively provide a total transfer capability of up to 2,500 MW, subject to individual tie-line limits. Table B.2 outlines the data sources, preparation process, and assumptions used in creating datasets for the prediction models.

Table B.2. Ontario to New York transmission flow data and assumptions overview.

	Description
Data source	https://www.ieso.ca/power-data/data-directory
Data preparation	IESO public hourly inter-tie schedule flow data can be accessed for the years spanning from 2002 to 2023.
Assumptions	Positive flow indicates that Ontario is exporting to NY, and negative flow indicates that Ontario is importing from NY.

Figure B.4 illustrates the historical monthly MaxFlow for Ontario from 2007 through 2024, alongside 2030 projected quartile scenarios (Q1, Q2, and Q3). Analyzing these trends helps assess future reliability and facilitates capacity planning under varying conditions.

Historical monthly peaks (2007–2023) reveal a clear seasonal cycle for ONT–NYISO transfers: flows typically increase in late winter/early spring (February–April) and again in late fall/early winter (November–December). Over 16 years, the average spring peaks hovered around 1,700–1,900 MW, with occasional spikes above 2,200 MW. The 2030 forecast for Q1, Q2, and Q3 aligns with this pattern, predicting a springtime peak near 1,800 MW, a summer trough around 1,400 MW, and a modest late-summer uptick near 1,500 MW.

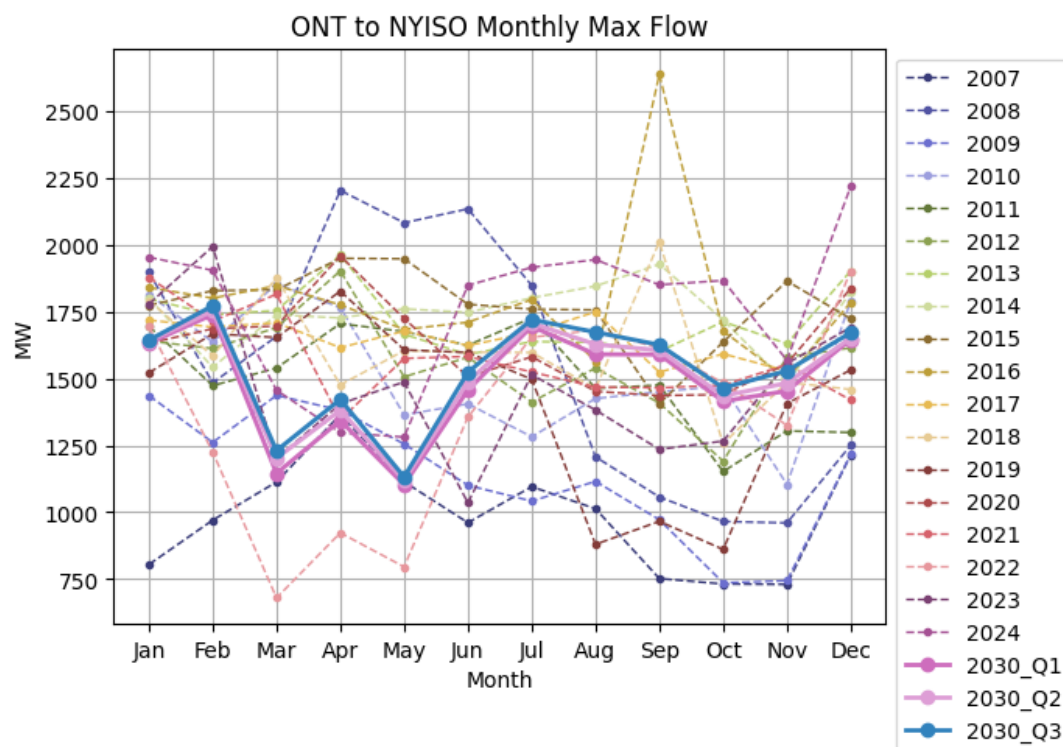


Figure B.4. Monthly maximum energy transfer between Ontario (ONT) and New York (NYISO).

The team used robust validation metrics to justify these results. When trained on daily data from the 2010–2024 period—including projected 2030 loads, seasonal flags, and holiday effects—the XGBoost model achieved $R^2 > 0.80$ and a root mean square error below 150 MW on an unseen 20 percent hold-out dataset. Moreover, the 95 percent confidence intervals for monthly maxima were narrow (approximately ± 150 MW), demonstrating low predictive uncertainty. A comparison of predicted maxima with historical extremes revealed that 2030 forecasts consistently fell within (or slightly above) the previous window of variability, implying realistic demand-driven behavior. In summary, the close alignment with historical peaks, strong cross-validated performance, and tight confidence bands collectively validate the results.

Discussion

The reason that the team used ML/XGBoost to approximate the 2030 transfer profiles was to ensure that there would be no violations or inconsistencies between transfer limits, load, and generation. The 15 years of data used were sufficient for having the models learn historical relationships and project them forward to 2030 to capture the underlying trends in load,

generation, and their interactions. The use of such an extensive dataset justifies using ML to establish consistent transfer profiles.

However, in some regions, like Ontario to NYISO, the available data encompassed a shorter time period, and the relationships were only partially captured because of a lack of neighboring-region data. In such cases, it was necessary to incorporate additional predictors, such as rolling and lag features from the transfer limits. Although the direct use of transfer limit data to project future transfer limits would typically be avoided, these engineered features help improve predictions when data coverage is sparse and the model's goodness-of-fit is low.

In all cases, the ML models ensured that these historical relationships were not violated, maintaining internal consistency among load, generation, and transfer limits. Overall, the team relied on ML when long-term data were available for training and projecting load and generation profiles. Rolling and lag features were used to reinforce the model when data availability was limited, but always with the goal of upholding consistent physical relationships in the 2030 projections.

Supplementary Plots for Additional Transfers

This section presents figures and tables showing results and source data information for each transfer listed below:

- (iii) Pacific Northwest to British Columbia
- (iv) Alberta to Montana
- (v) Manitoba to MISO West
- (vi) Ontario to MISO West
- (vii) Ontario to MISO East
- (viii) Ontario to New York
- (ix) Hydro-Quebec to New York
- (x) Hydro-Quebec to New England
- (xi) New Brunswick to New England

The figures show the daily MaxFlow for each transfer that was considered in this analysis.

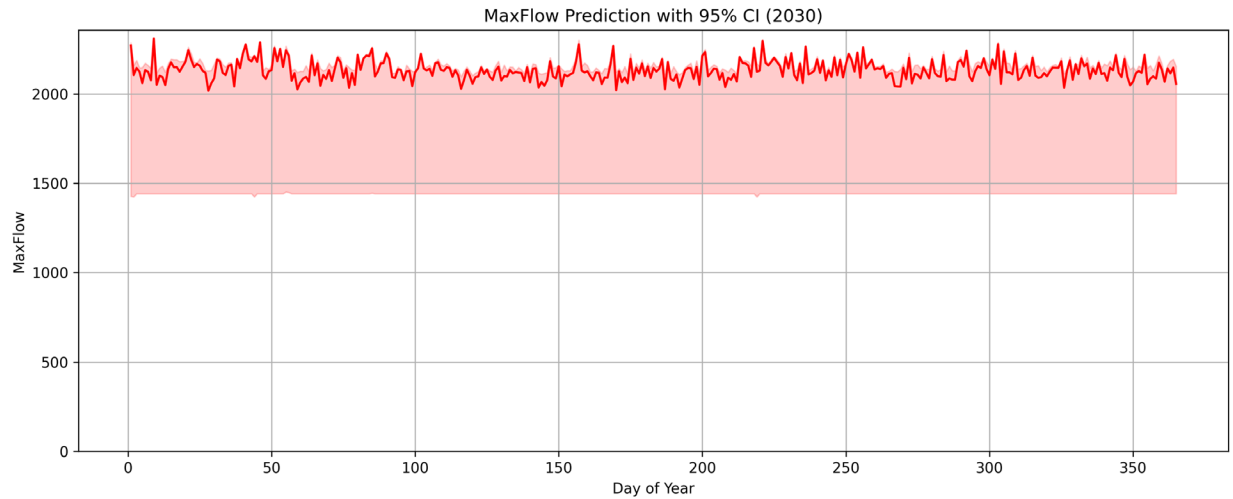


Figure B.5. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between British Columbia and the Pacific Northwest.

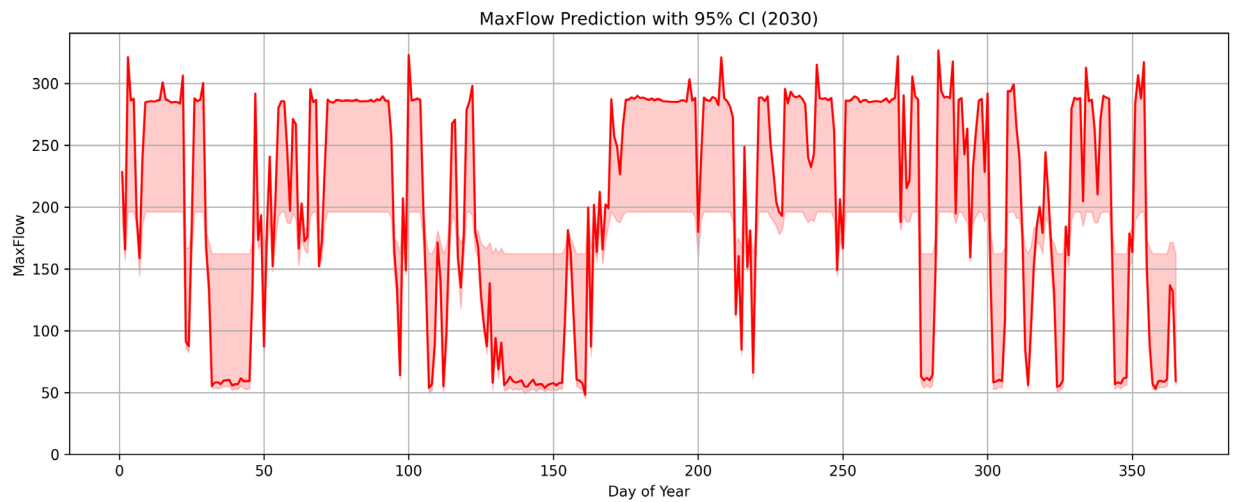


Figure B.6. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between AESO and Montana.

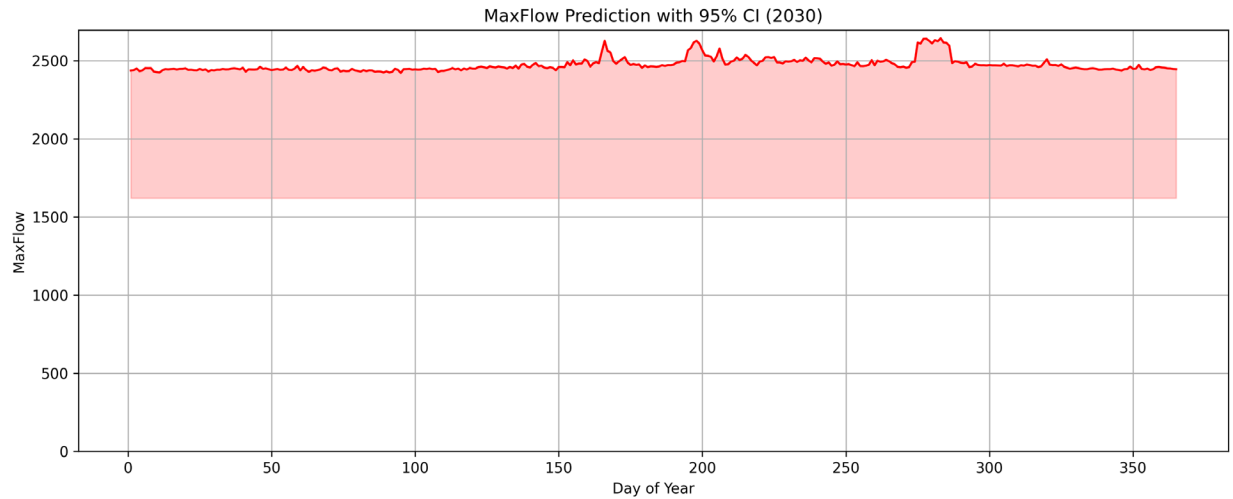


Figure B.7. Projected 2030 maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Manitoba and MISO.

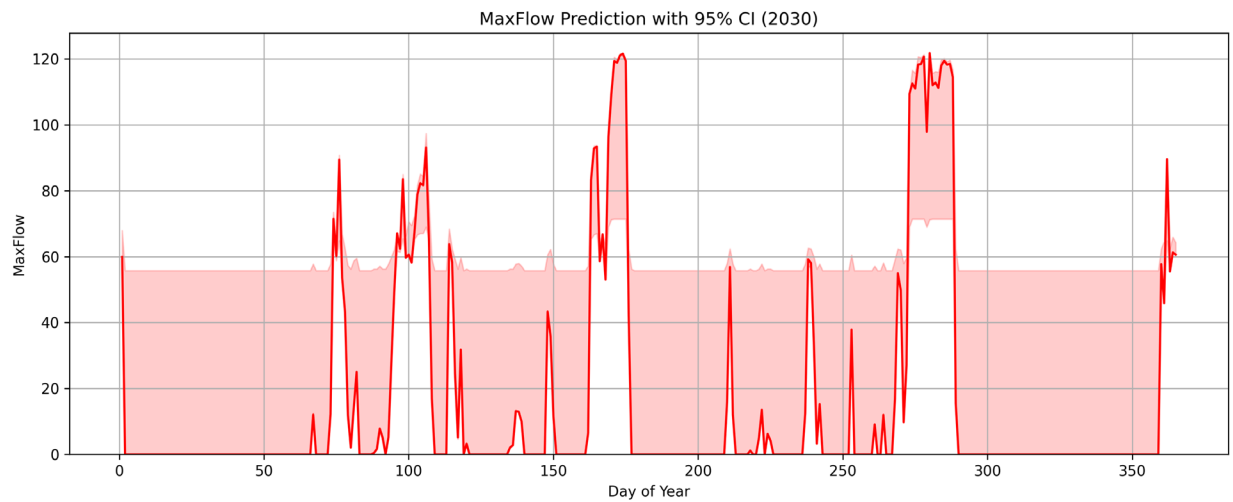


Figure B.8. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and MISO West.

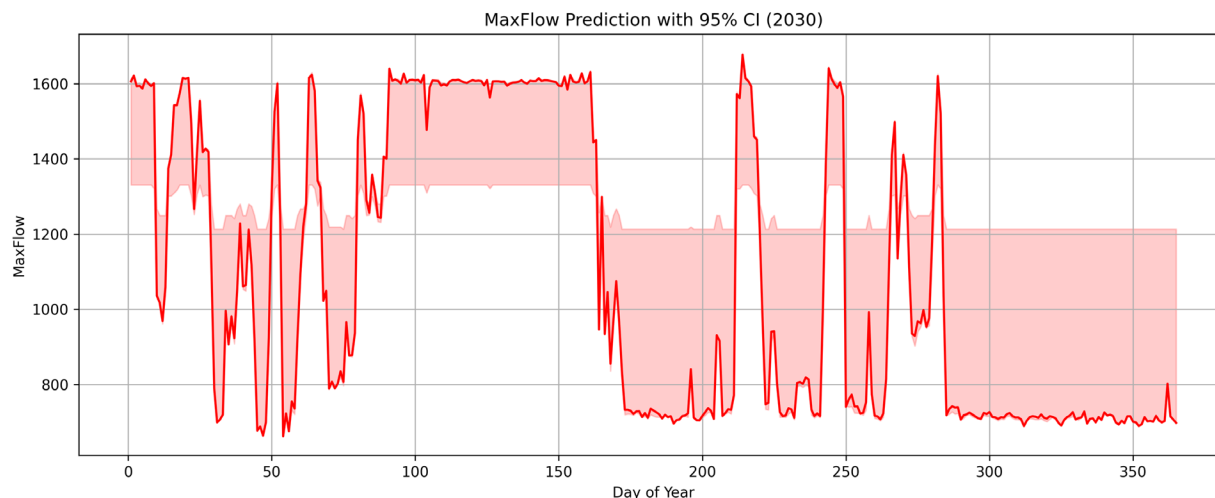


Figure B.9. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and MISO East.

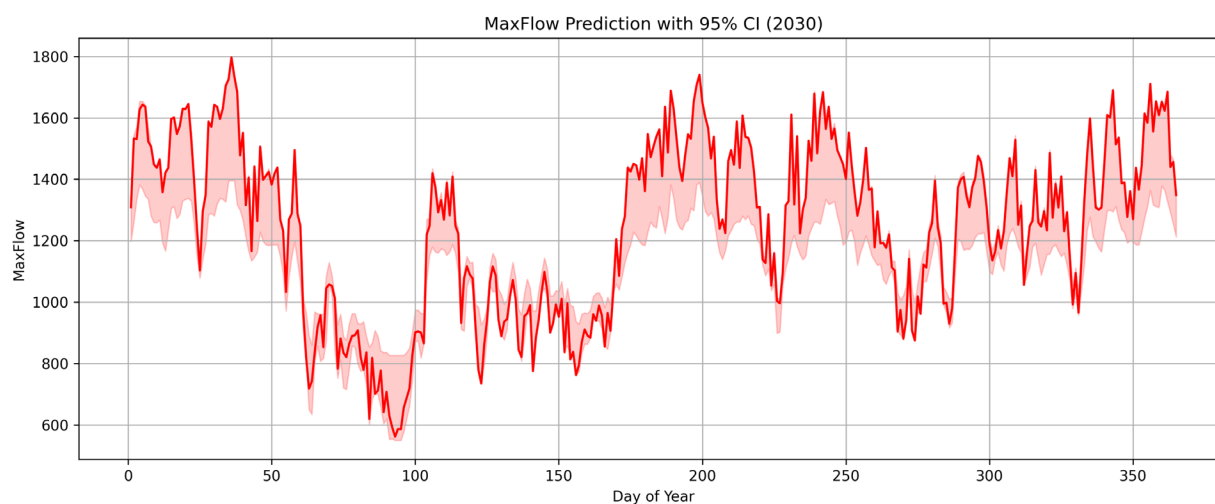


Figure B.10. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and New York.

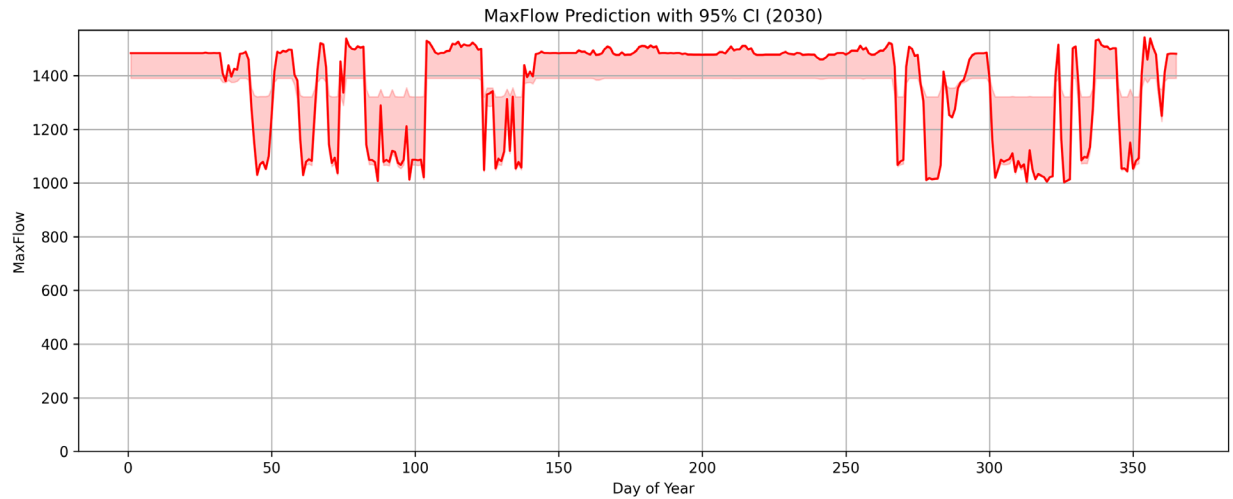


Figure B.11. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Quebec and New York.

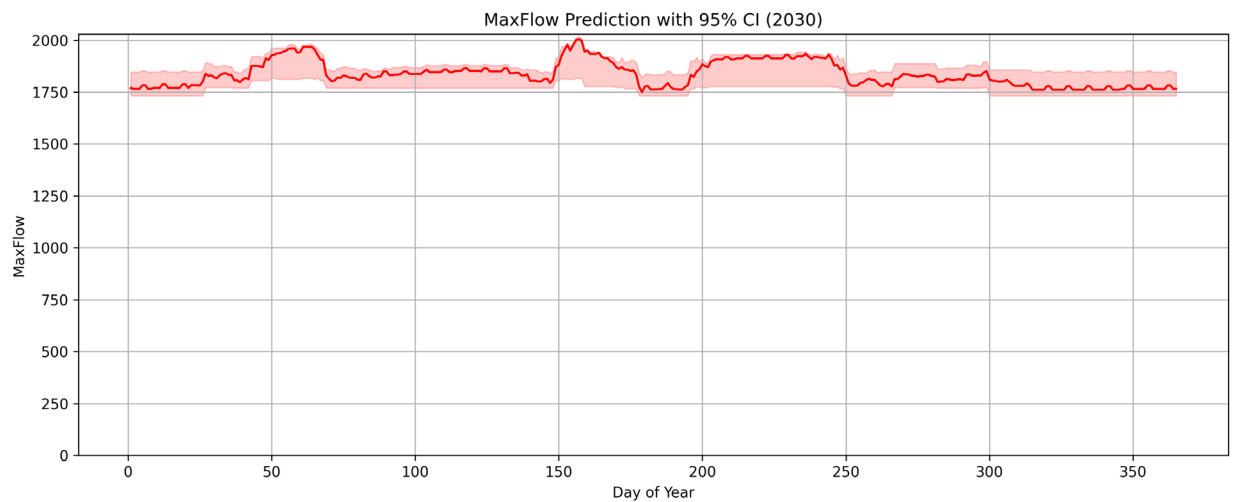


Figure B.12. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Quebec and New England.

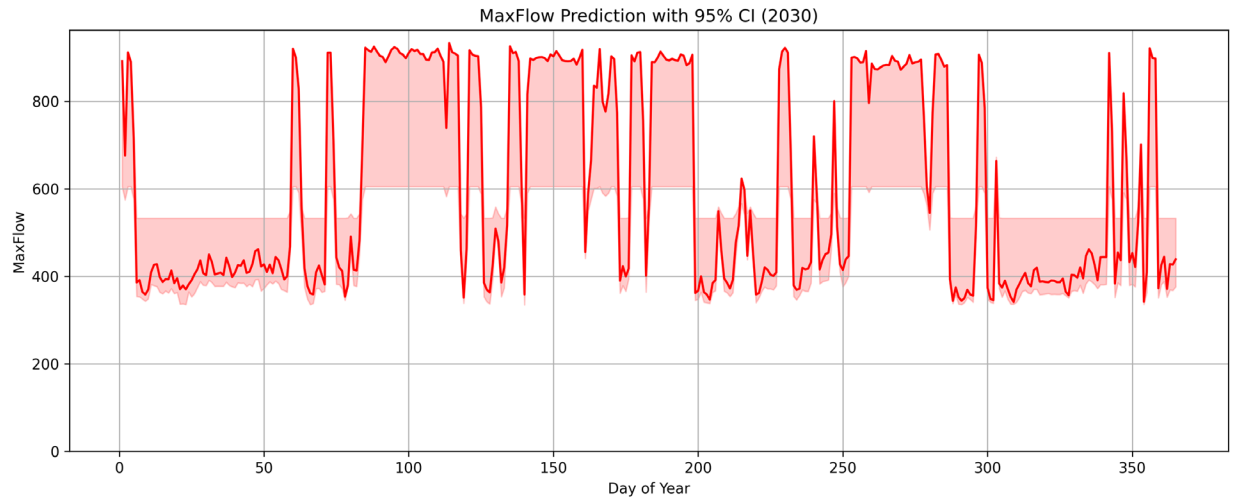


Figure B.13. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between New Brunswick and New England.

References

1. AESO. 2019. "Annual Market Statistics Report" https://public.tableau.com/app/profile/market.analytics/viz/AnnualStatistics_16161854228350/Introduction Last updated May 13, 2025.
2. AESO. "Hourly Metered Volumes and Pool Price and AIL" https://www.aeso.ca/assets/Uploads/data-requests/Hourly_Metered_Volumes_and_Pool_Price_and_AIL.csv Accessed May 30, 2025.
3. AESO. 2016 "Historical Generation Data (CSD)" <https://www.aeso.ca/market/market-and-system-reporting/data-requests/historical-generation-data> Accessed May 30, 2025.
4. BC Hydro. 2025. "Historical Transmission Data" <https://www.bchydro.com/energy-in-bc/operations/transmission/transmission-system/balancing-authority-load-data/historical-transmission-data.html>
5. BPA. "Rolling 30 Days and Monthly History" <https://transmission.bpa.gov/business/operations/paths/> Accessed May 30, 2025.
6. BPA. "VER* Generation and Total Load in The BPA Balancing Authority" <https://transmission.bpa.gov/business/operations/wind/> Accessed May 30, 2025.
7. Government of Canada. 2022. "Historical Data on Electricity Consumption and Production in Quebec" <https://open.canada.ca/data/en/dataset/bd6a1401-15db-438d-9b8b-ff11af48064e> Updated July 24, 2024.
8. IESO. 2025. "Data Directory" <https://www.ieso.ca/power-data/data-directory>
9. IESO. 2019. "Yearly Intertie Actual Schedule and Flow Report" <https://reports-public.ieso.ca/public/IntertieScheduleFlowYear/> Updated May 30, 2025.
10. IESO. 2018. "Hourly Demand Report" <https://reports-public.ieso.ca/public/Demand/> Updated May 30, 2025.
11. IESO. 2025. "Generator Output by Fuel Type Hourly Report" <https://reports-public.ieso.ca/public/GenOutputbyFuelHourly/> Updated May 30, 2025.
12. ISO-NE. 2025. "Energy, Load, and Demand Reports: Zonal Information" <https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/zone-info>
13. ISO-NE. 2025. "Energy, Load, and Demand Reports: Historical Hourly Flows and Limits" <https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/historical-hourly-flows-and-limits>
14. MISO. "Load, Generation, and Interchange API" <https://data-exchange.misoenergy.org/api-details#api=load-generation-and-interchange-api&operation=get-v1-real-time-date-interchange-net-actual> Accessed May 30, 2025.

15. NB Power. 2025. "System Information Archive"
https://tso.nbpower.com/Public/en/system_information_archive.aspx Accessed May 30, 2025.
16. NYISO. 2002 "Internal and External Interface Limits and Flows"
<https://mis.nyiso.com/public/P-32list.htm> Updated May 30, 2025.
17. NYISO. 2004 "Day-Ahead Markey Daily Energy Report" <https://mis.nyiso.com/public/P-30list.htm> Updated May 30, 2025
18. Stephen et al. 2022. "Clarifying the Interpretation and Use of the LOLE Resource Adequacy Metric" <https://www.spp.org/documents/69303/lole%20metric.pdf>

EO 14262



Presidential Documents

Executive Order 14262 of April 8, 2025

Strengthening the Reliability and Security of the United States Electric Grid

By the authority vested in me as President by the Constitution and the laws of the United States of America, it is hereby ordered:

Section 1. Purpose. The United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and an increase in domestic manufacturing. This increase in demand, coupled with existing capacity challenges, places a significant strain on our Nation's electric grid. Lack of reliability in the electric grid puts the national and economic security of the American people at risk. The United States' ability to remain at the forefront of technological innovation depends on a reliable supply of energy from all available electric generation sources and the integrity of our Nation's electric grid.

Sec. 2. Policy. It is the policy of the United States to ensure the reliability, resilience, and security of the electric power grid. It is further the policy of the United States that in order to ensure adequate and reliable electric generation in America, to meet growing electricity demand, and to address the national emergency declared pursuant to Executive Order 14156 of January 20, 2025 (Declaring a National Energy Emergency), our electric grid must utilize all available power generation resources, particularly those secure, redundant fuel supplies that are capable of extended operations.

Sec. 3. Addressing Energy Reliability and Security with Emergency Authority. (a) To safeguard the reliability and security of the United States' electric grid during periods when the relevant grid operator forecasts a temporary interruption of electricity supply is necessary to prevent a complete grid failure, the Secretary of Energy, in consultation with such executive department and agency heads as the Secretary of Energy deems appropriate, shall, to the maximum extent permitted by law, streamline, systemize, and expedite the Department of Energy's processes for issuing orders under section 202(c) of the Federal Power Act during the periods of grid operations described above, including the review and approval of applications by electric generation resources seeking to operate at maximum capacity.

(b) Within 30 days of the date of this order, the Secretary of Energy shall develop a uniform methodology for analyzing current and anticipated reserve margins for all regions of the bulk power system regulated by the Federal Energy Regulatory Commission and shall utilize this methodology to identify current and anticipated regions with reserve margins below acceptable thresholds as identified by the Secretary of Energy. This methodology shall:

- (i) analyze sufficiently varied grid conditions and operating scenarios based on historic events to adequately inform the methodology;
- (ii) accredit generation resources in such conditions and scenarios based on historical performance of each specific generation resource type in the real time conditions and operating scenarios of each grid scenario; and
- (iii) be published, along with any analysis it produces, on the Department of Energy's website within 90 days of the date of this order.

(c) The Secretary of Energy shall establish a process by which the methodology described in subsection (b) of this section, and any analysis and results it produces, are assessed on a regular basis, and a protocol to identify which generation resources within a region are critical to system reliability. This protocol shall additionally:

(i) include all mechanisms available under applicable law, including section 202(c) of the Federal Power Act, to ensure any generation resource identified as critical within an at-risk region is appropriately retained as an available generation resource within the at-risk region; and

(ii) prevent, as the Secretary of Energy deems appropriate and consistent with applicable law, including section 202 of the Federal Power Act, an identified generation resource in excess of 50 megawatts of nameplate capacity from leaving the bulk-power system or converting the source of fuel of such generation resource if such conversion would result in a net reduction in accredited generating capacity, as determined by the reserve margin methodology developed under subsection (b) of this section.

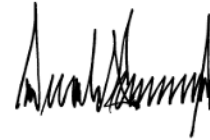
Sec. 4. General Provisions. (a) Nothing in this order shall be construed to impair or otherwise affect:

(i) the authority granted by law to an executive department or agency, or the head thereof; or

(ii) the functions of the Director of the Office of Management and Budget relating to budgetary, administrative, or legislative proposals.

(b) This order shall be implemented consistent with applicable law and subject to the availability of appropriations.

(c) This order is not intended to, and does not, create any right or benefit, substantive or procedural, enforceable at law or in equity by any party against the United States, its departments, agencies, or entities, its officers, employees, or agents, or any other person.



THE WHITE HOUSE,
April 8, 2025.

[FR Doc. 2025-06381
Filed 4-11-25; 8:45 am]
Billing code 3395-F4-P

Available at (accessed on 5/27/2025):

<https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid>



U.S. DEPARTMENT
of **ENERGY**

For more information, visit:
energy.gov/topics/reliability

DOE/Publication Number • July, 7 2025