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DOE Final EO Report (FINAL JULY 7)



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.

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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
LBNL	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.

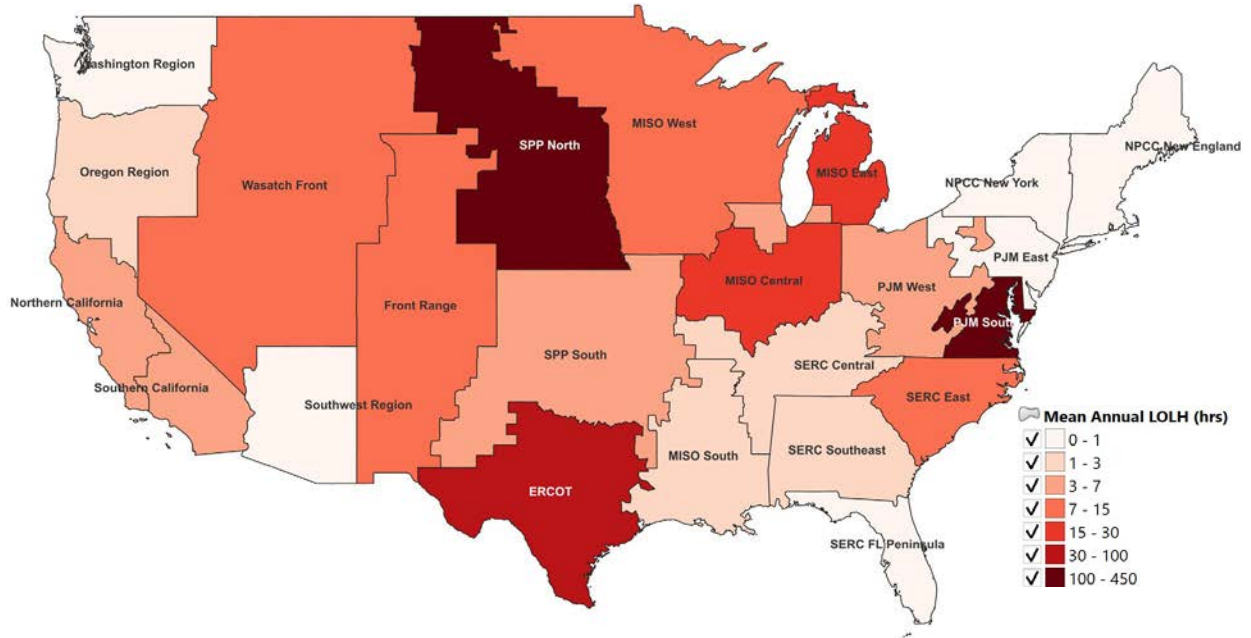


Figure 1. Mean Annual LOLH by Region (2030) – Plant Closures

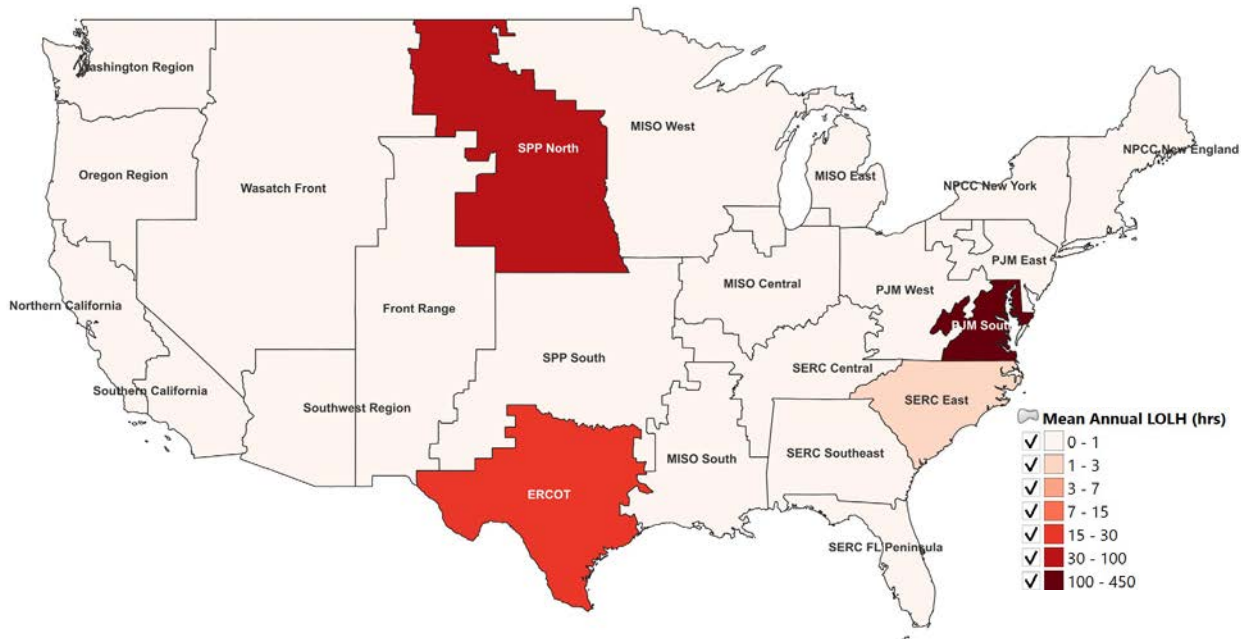


Figure 2. Mean Annual LOLH by Region (2030) – No Plant Closures

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

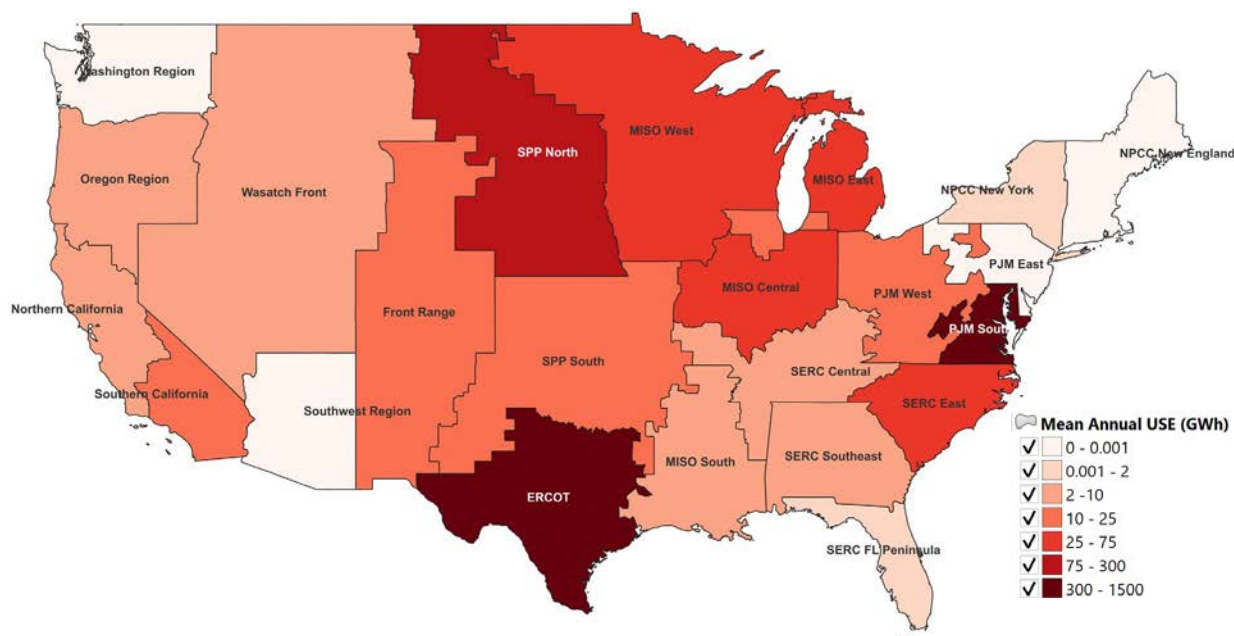


Figure 3. Mean Annual NUSE by Region (2030) -Plant Closures

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.

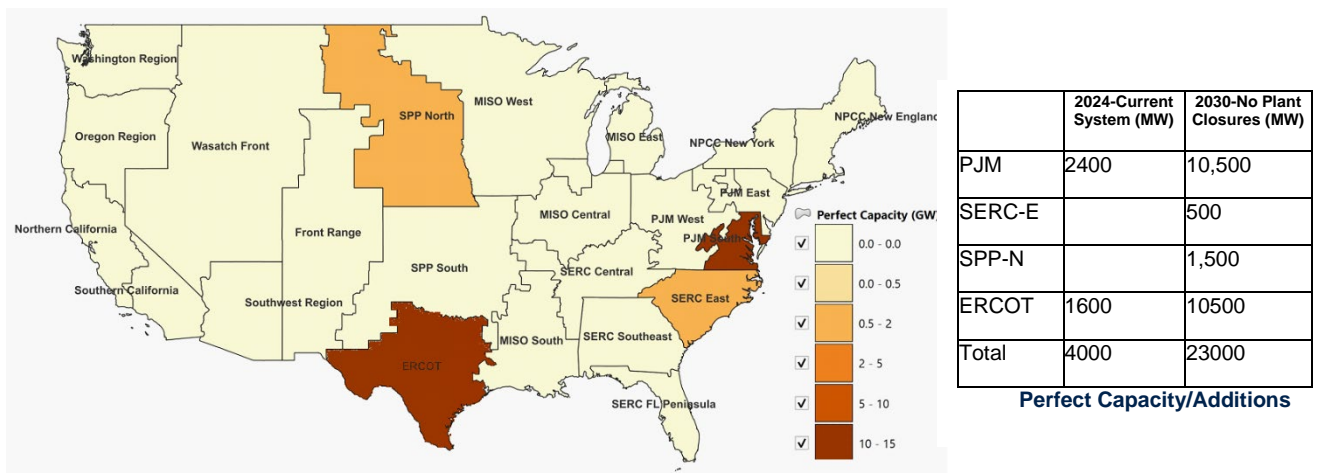


Figure 4. Tuned Perfect Capacity (MW) By Region

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.

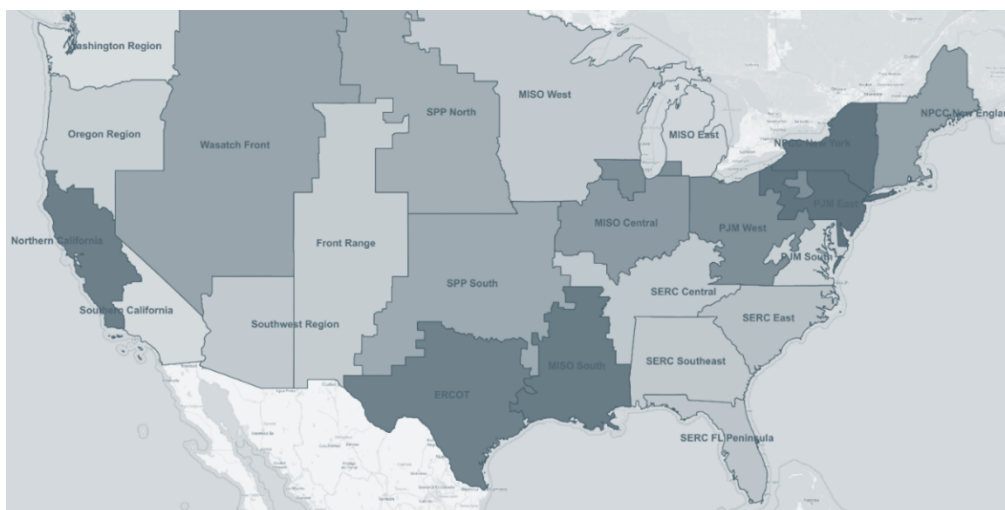


Figure 5. TPRs used in NERC ITCS

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.

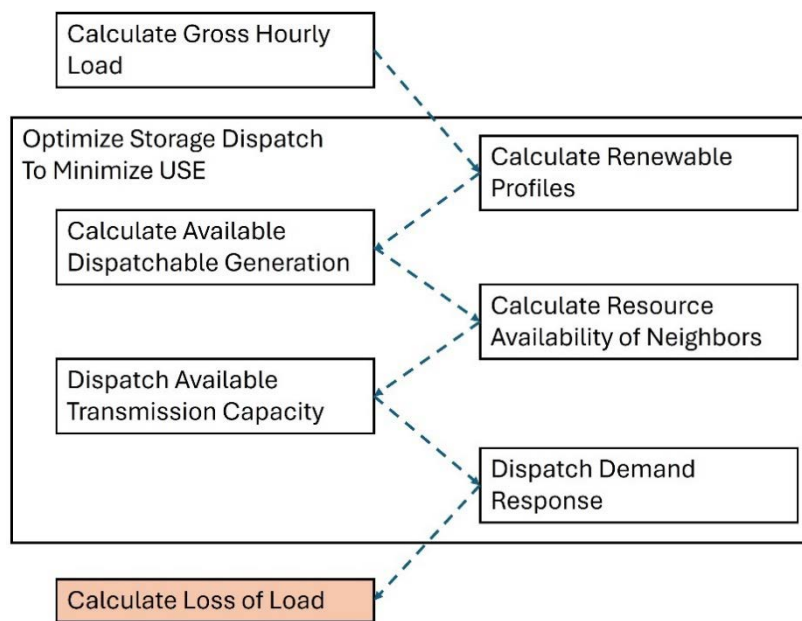


Figure 6. Simplified Overview of Model

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.

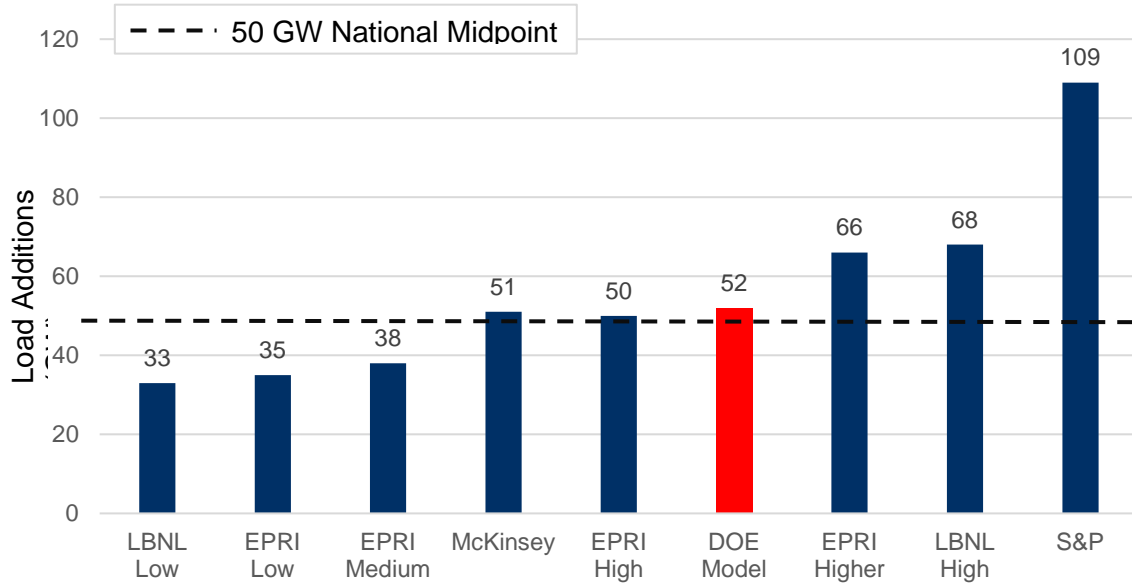


Figure 7. 2024 to 2030 Projected Data Center Load Additions

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.

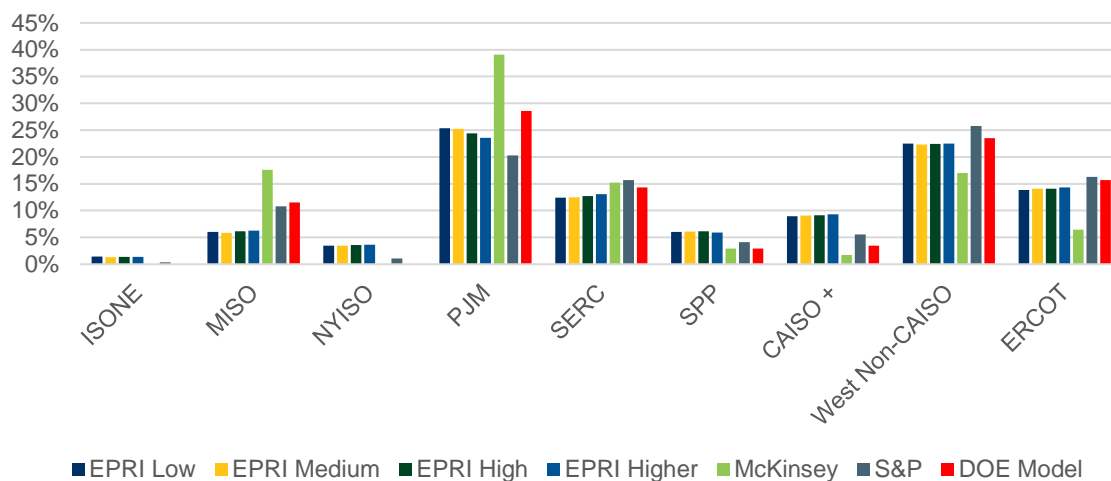


Figure 8. New Data Center Build (% Split by ISO/RTO) (2030 Estimated)

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.

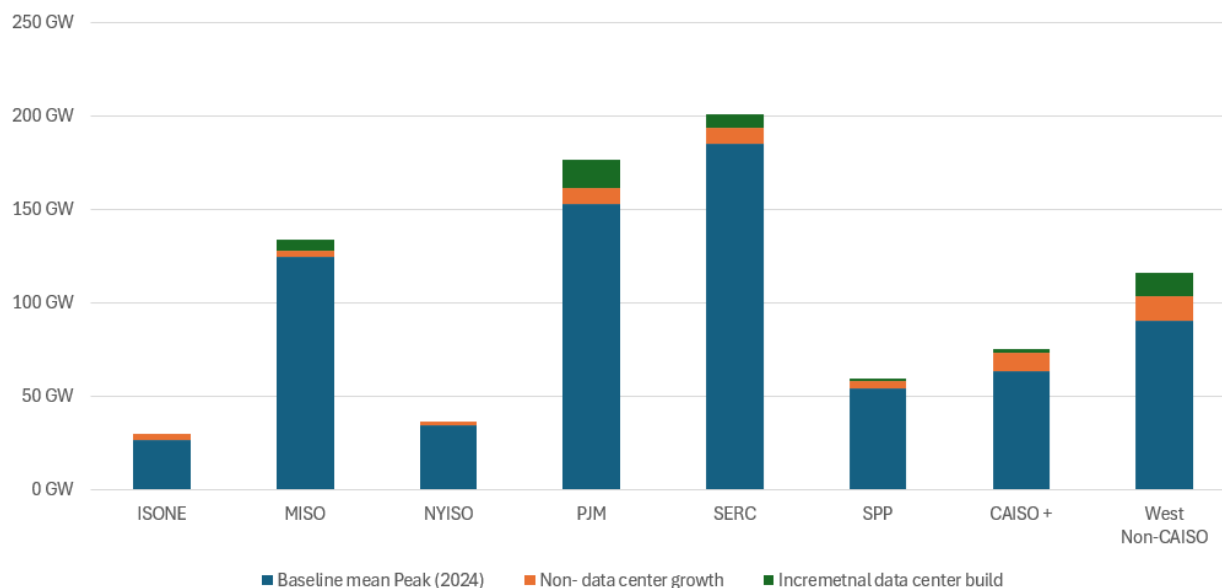


Figure 9. Mean Peak Load by RTO (Current Case vs 2030 Case)

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.

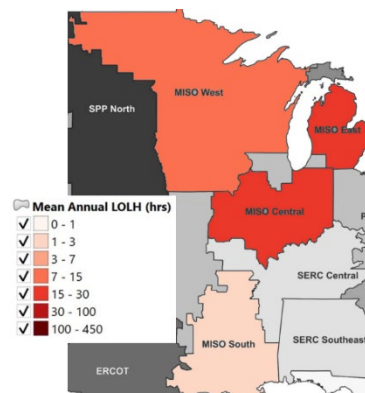


Table 2. Summary of MISO Reliability Metrics

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.

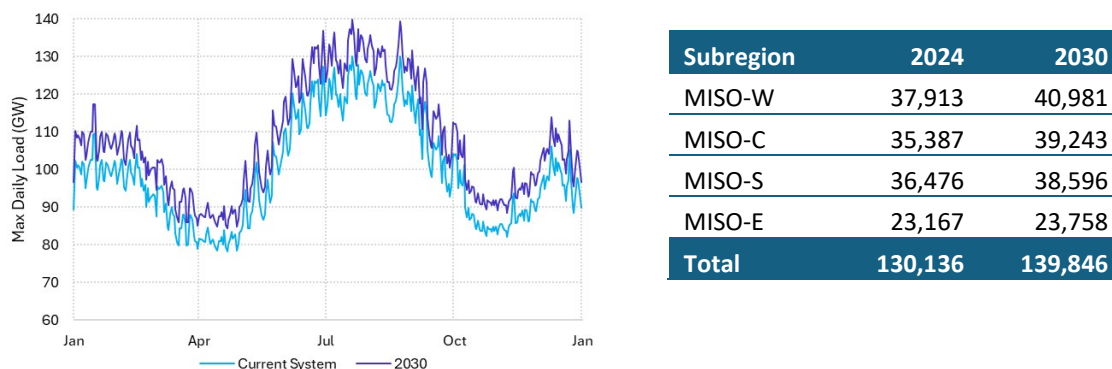


Figure 10. MISO Max Daily Load in the Current System versus 2030

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.

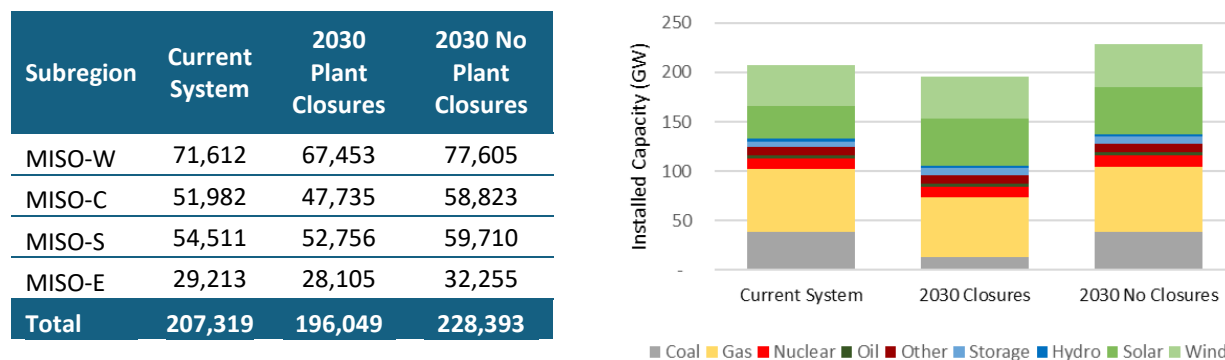


Figure 11. MISO Generation Capacity by Technology and Scenario

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.

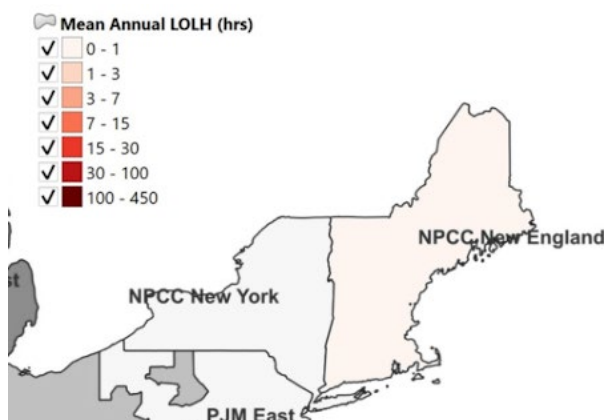
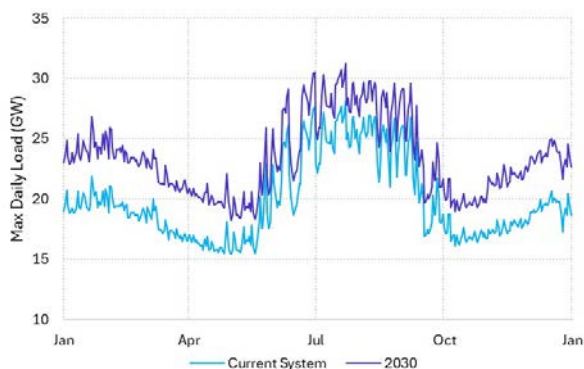


Table 4. Summary of ISO-NE Reliability Metrics

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

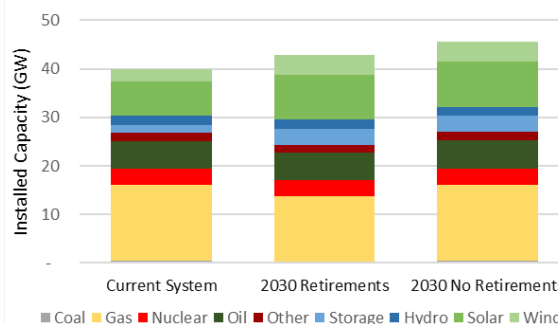


Figure 13. ISO-NE Generation Capacity by Technology and Scenario

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
ISONNE	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
ISONNE	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)
ISONNE	(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.

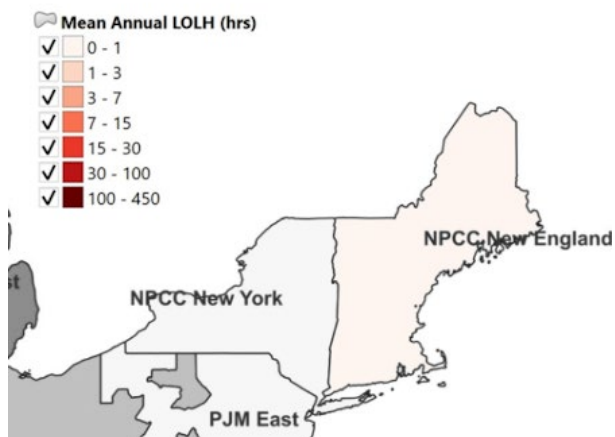


Table 6. Summary of NYISO Reliability Metrics

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.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
NYISO	45,924	50,396	51,444
Total	45,924	50,396	51,444

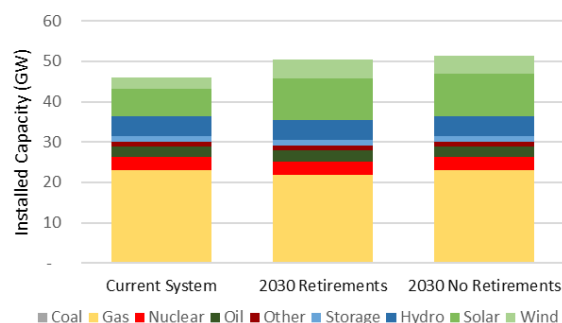


Figure 15. NYISO Generation Capacity by Technology and Scenario

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.

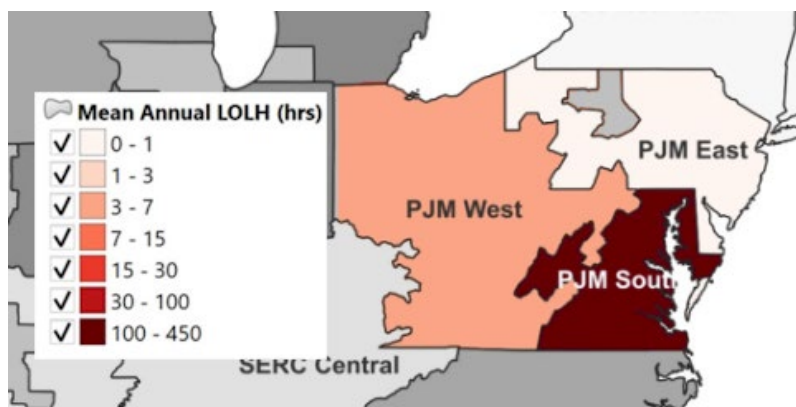
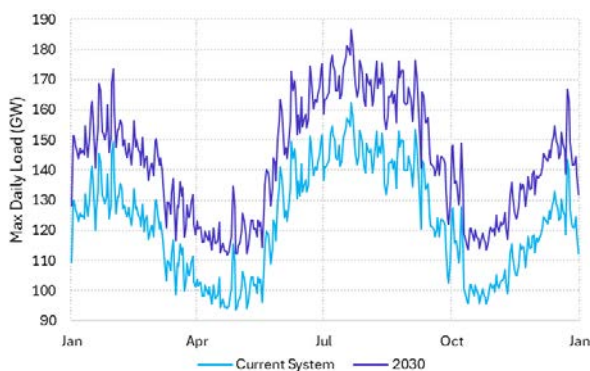


Table 8. Summary of PJM Reliability Metrics

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

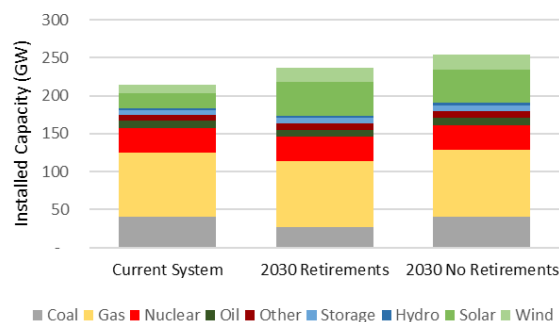


Figure 17. PJM Generation Capacity by Technology and Scenario

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.

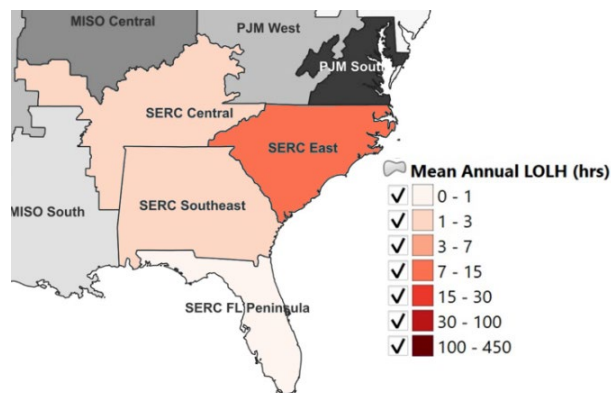
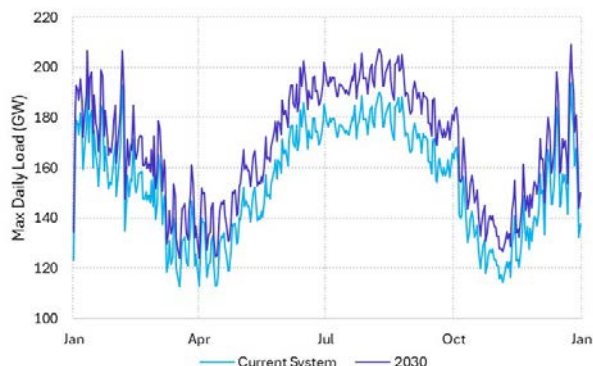


Table 10. Summary of SERC Reliability Metrics

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

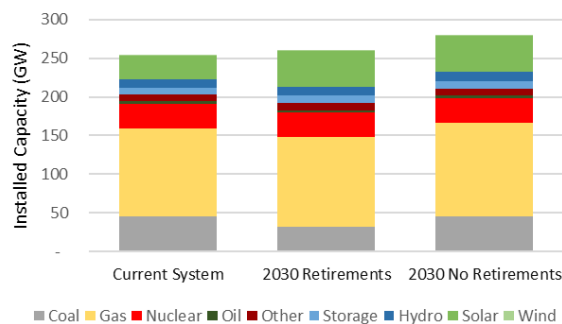


Figure 19. SERC Generation Capacity by Technology and Scenario

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.

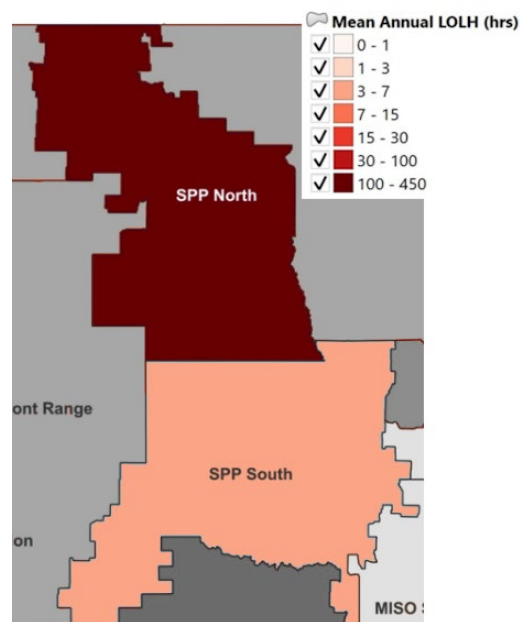
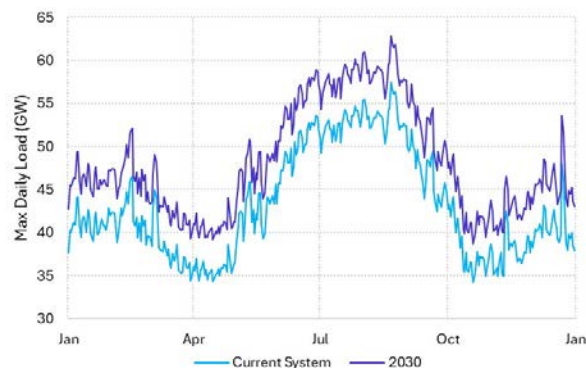


Table 12. Summary of SPP Reliability Metrics

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

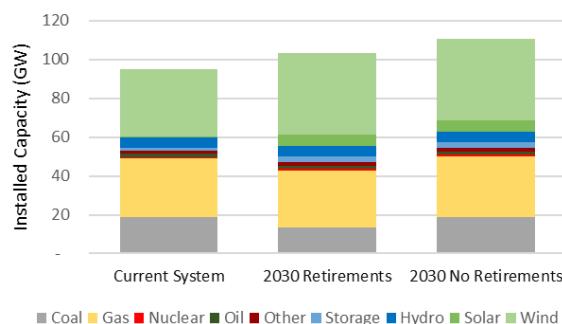


Figure 21. SPP Generation Capacity by Technology and Scenario

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.

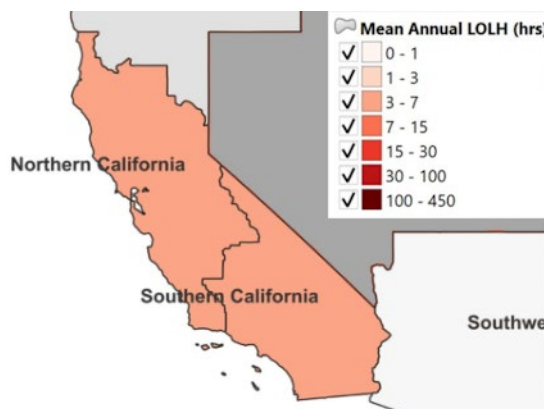
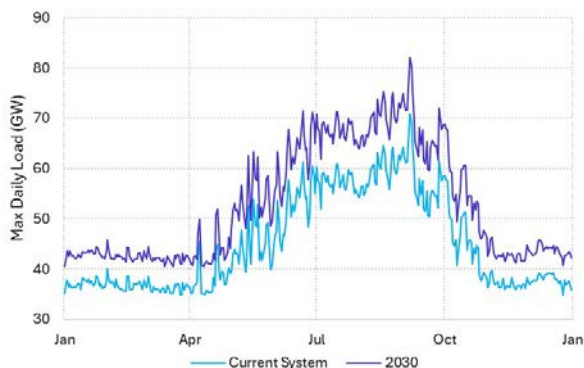


Table 14. Summary of CAISO+ Reliability Metrics

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

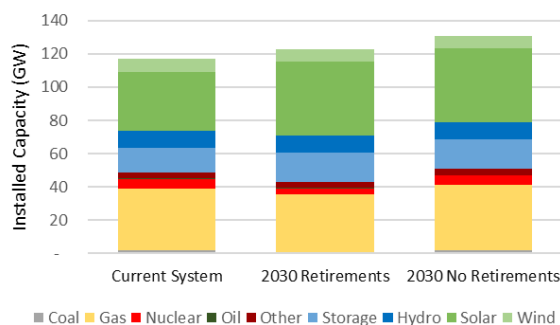


Figure 23. CAISO+ Generation Capacity by Technology and Scenario

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.

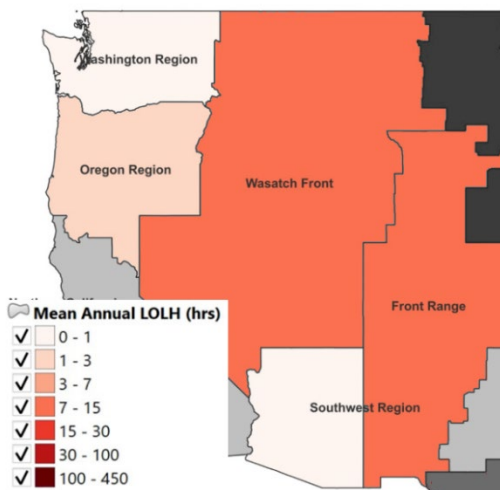
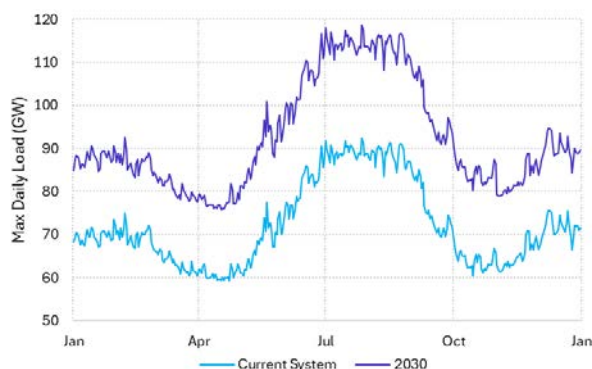


Table 16. Summary of West Non-CAISO Reliability Metrics

Reliability Metric	Current System	2030 Projection		
		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

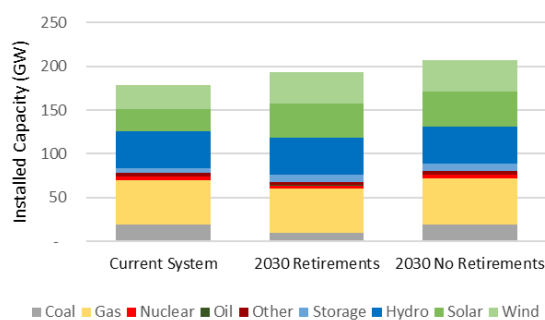


Figure 25. West Non-CAISO Generation Capacity by Technology and Scenario

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.

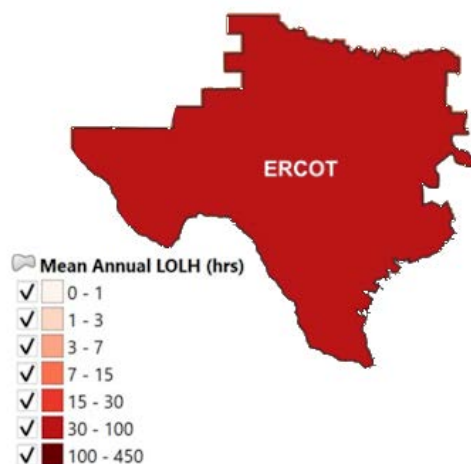
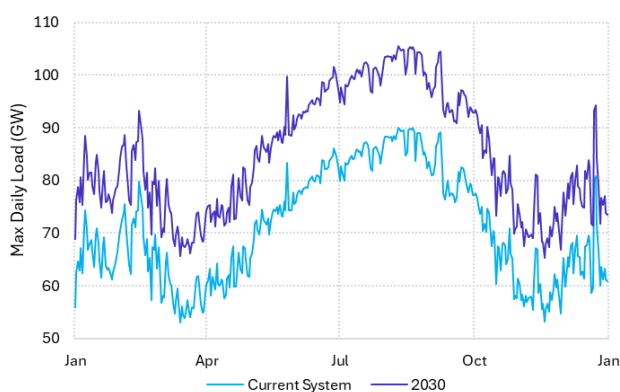


Table 18. Summary of ERCOT Reliability Metrics

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).



Subregion	2024	2030
ERCOT	90,075	105,485
Total	90,075	105,485

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.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
ERCOT	157,490	208,894	212,916
Total	157,490	208,894	212,916

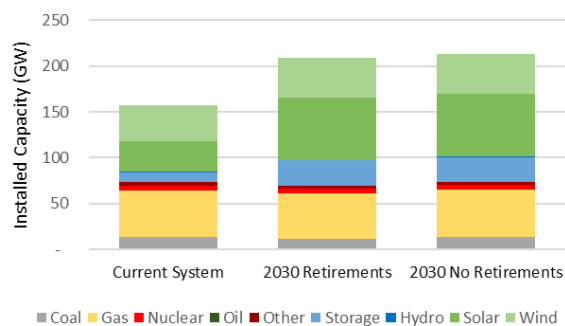


Figure 27. ERCOT Generation Capacity by Technology and Scenario

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.

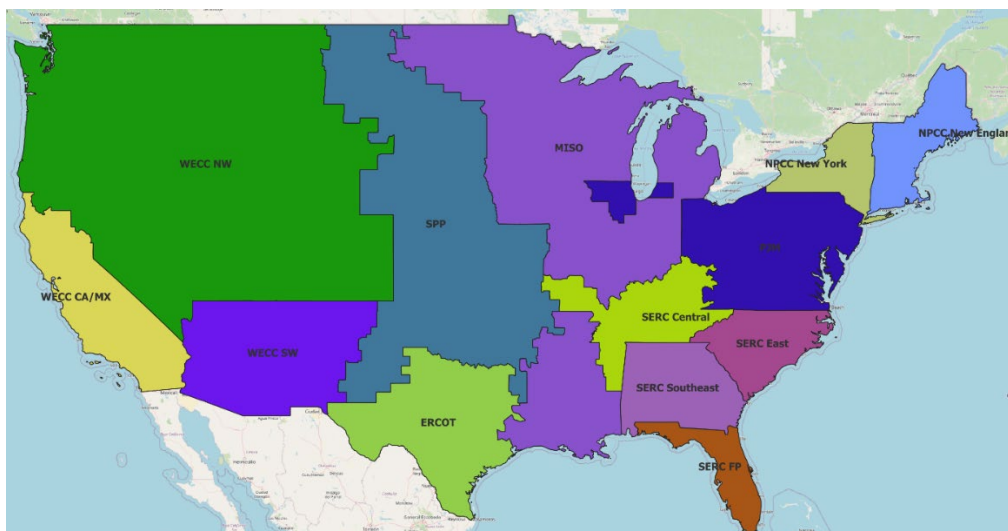


Figure A.1. NERC assessment areas.

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	
WECC-SW	Front Range	2 to 1

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	

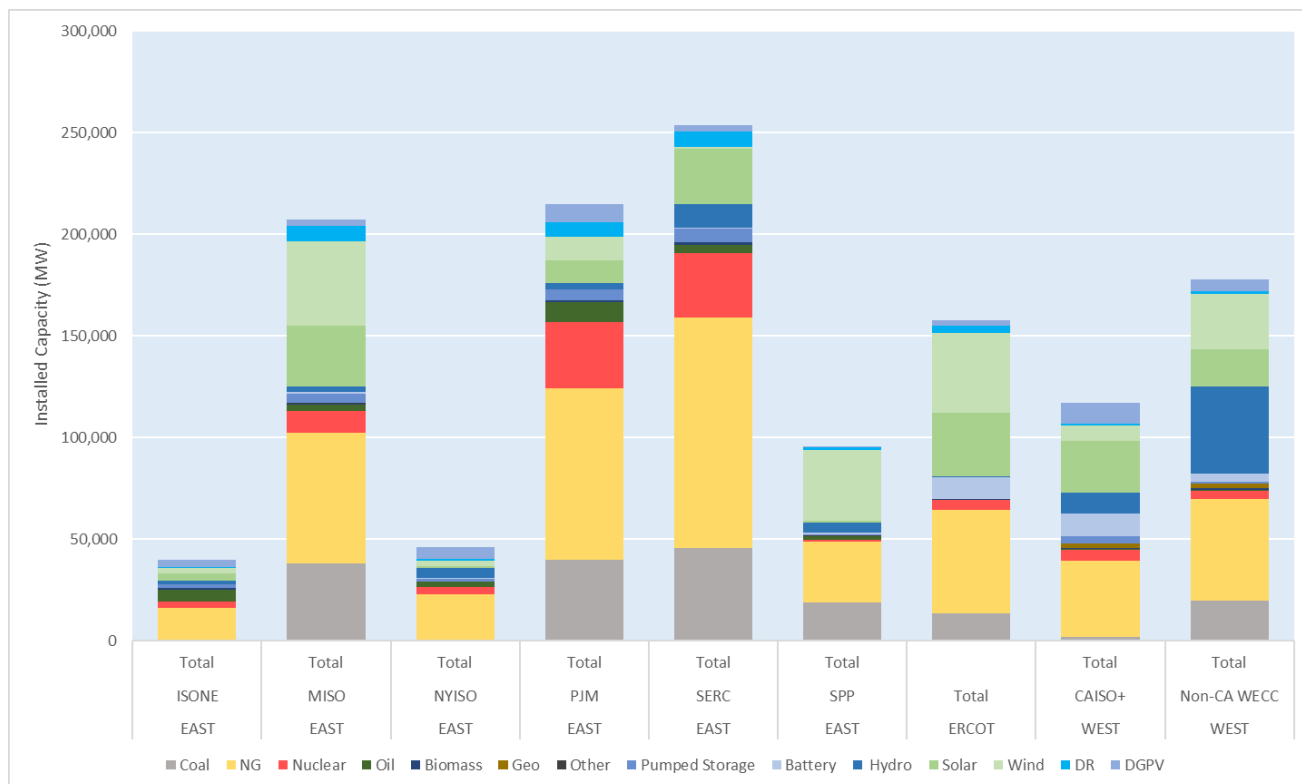


Figure A.2. Existing and Tier 1 capacities by NERC assessment area in 2024.

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.

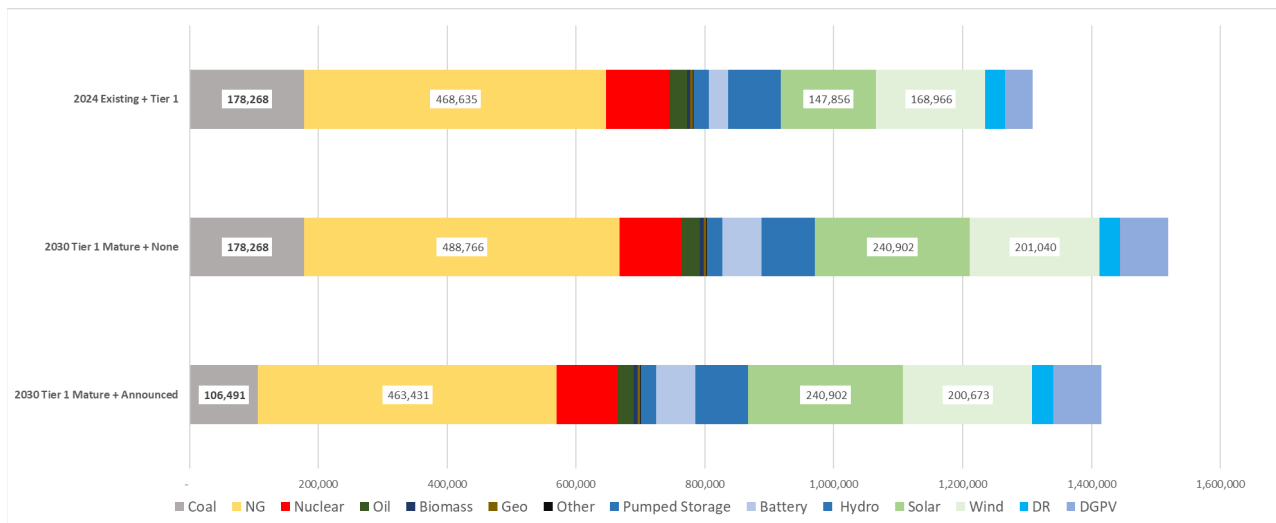


Figure A.9. Comparison of 2030 generation stacks for the various scenarios.

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
	ISONNE 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	180	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.

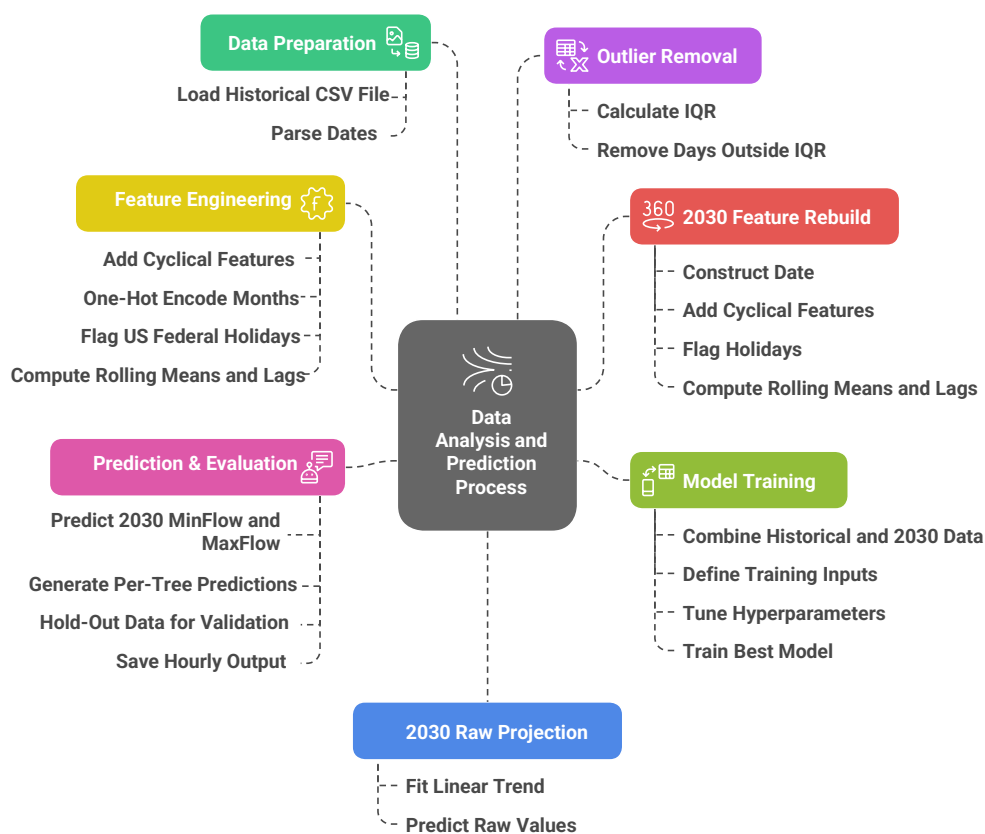


Figure B.1. Data analysis and prediction process.

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.

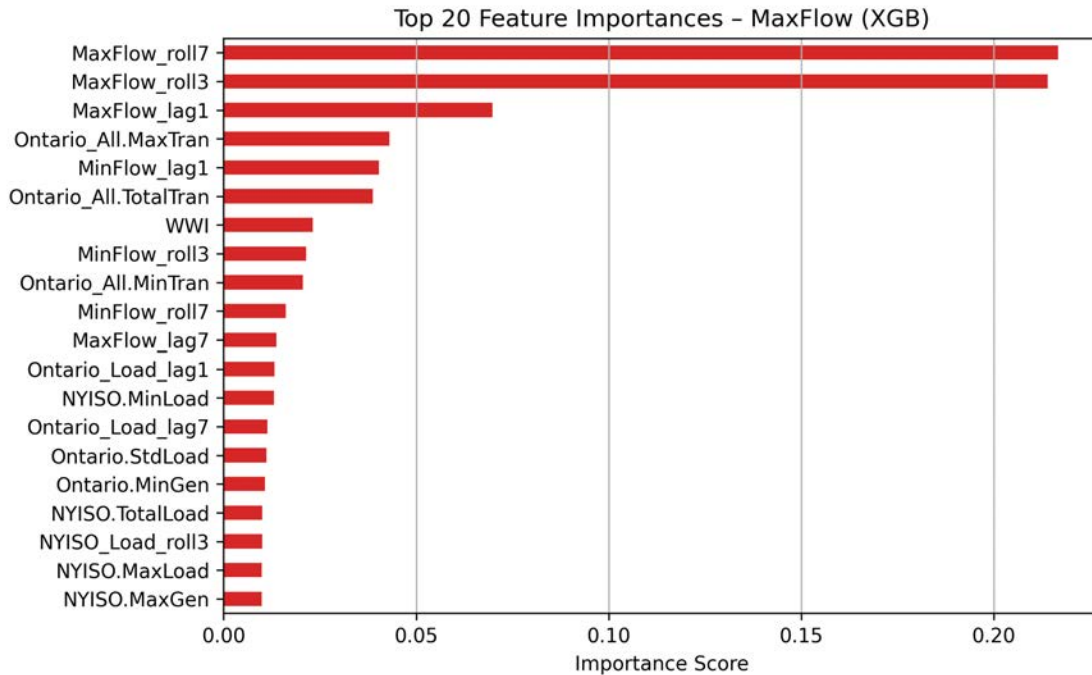


Figure B.2. Feature importance for predicting the hourly maximum energy transfer (MaxFlow) between NYISO and Ontario. XGB = eXtreme Gradient Boosting.

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.

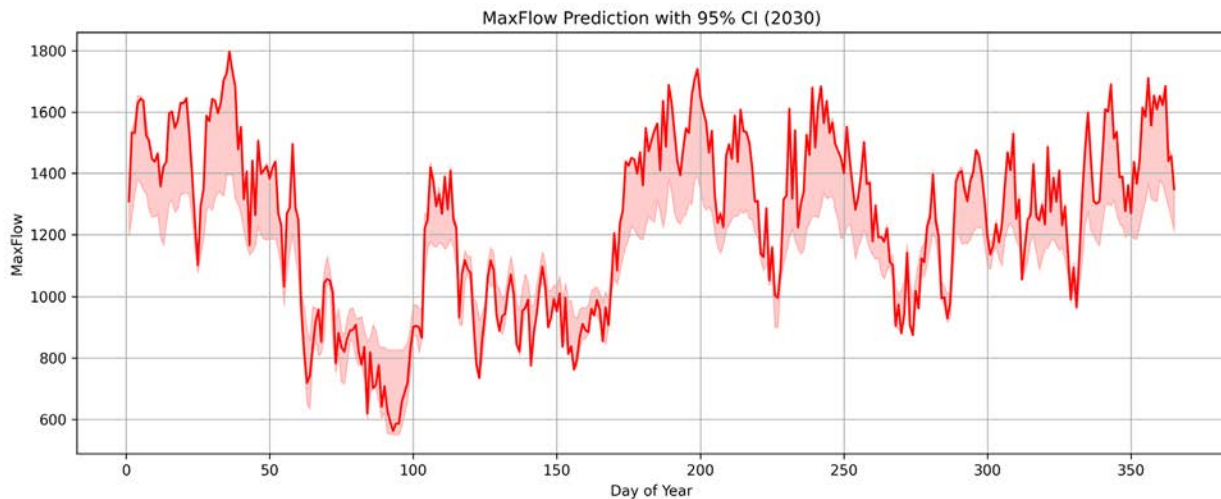


Figure B.3. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI).

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.

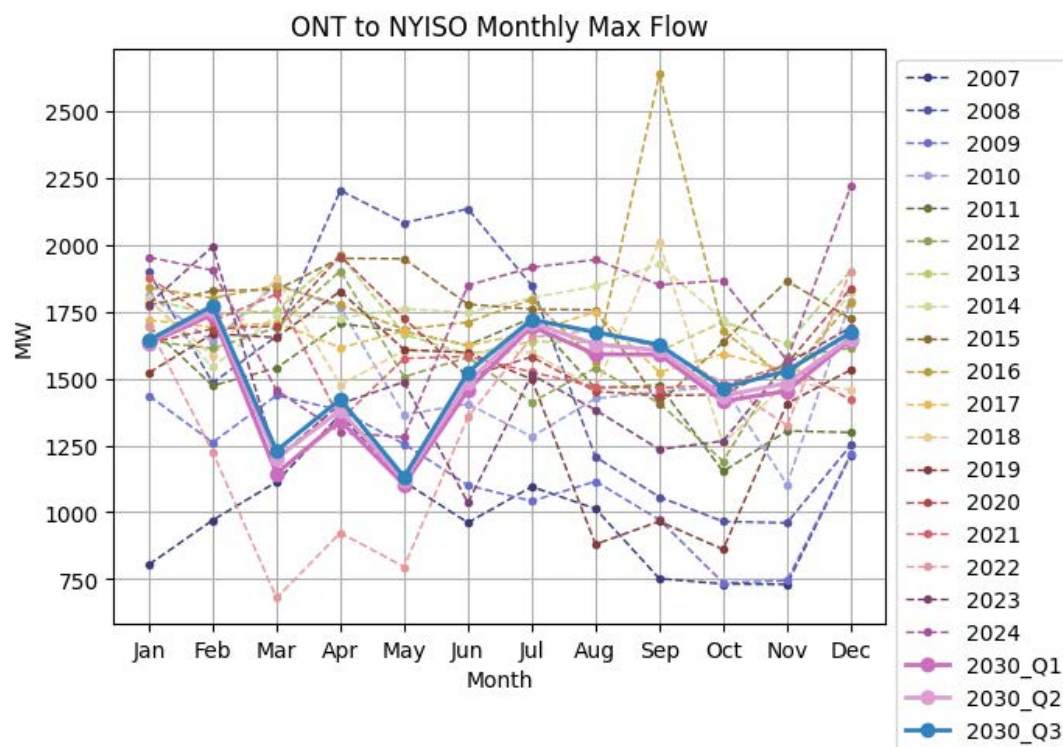


Figure B.4. Monthly maximum energy transfer between Ontario (ONT) and New York (NYISO).

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.

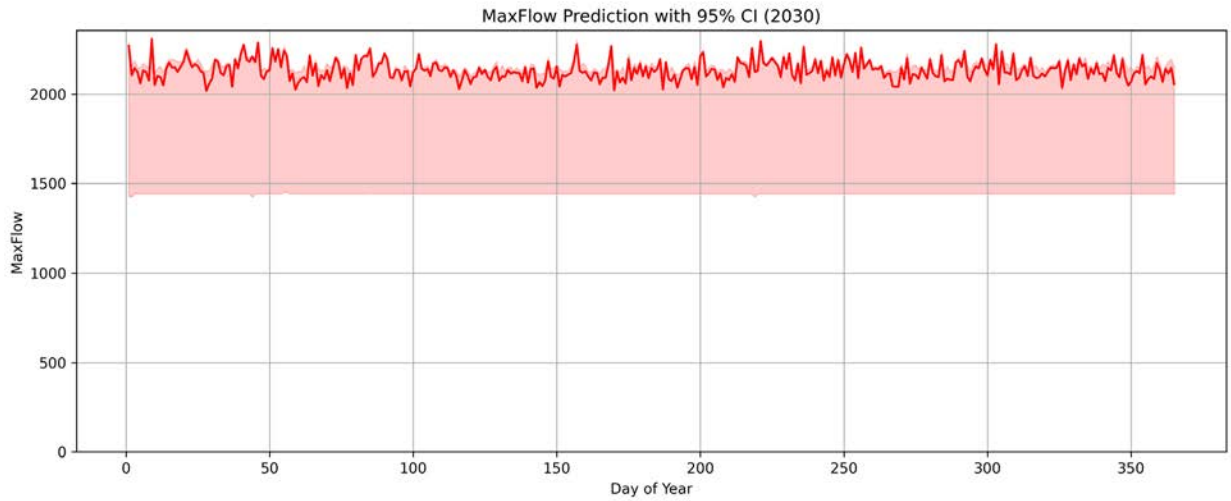


Figure B.5. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between British Columbia and the Pacific Northwest.

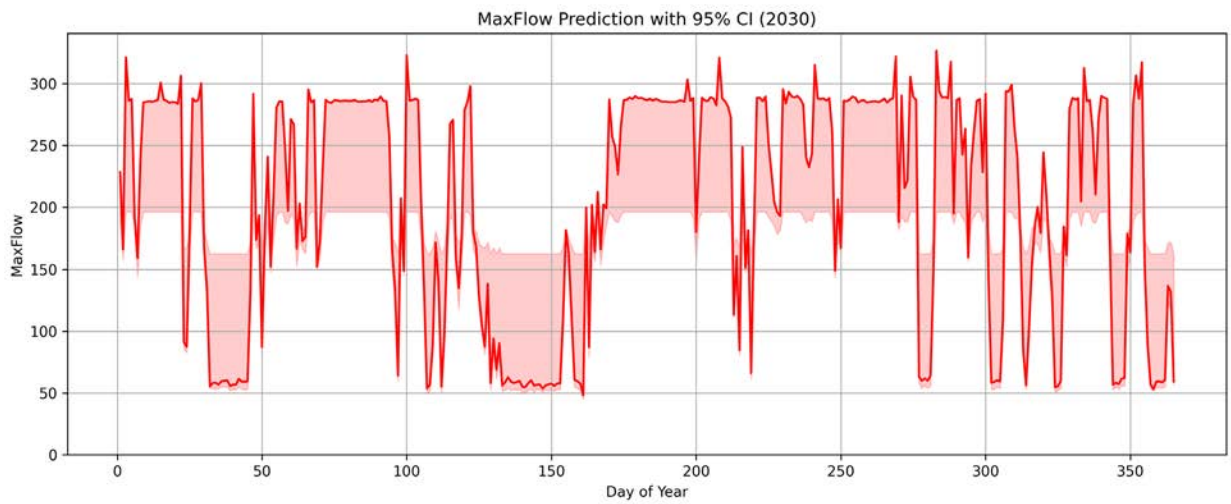


Figure B.6. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between AESO and Montana.

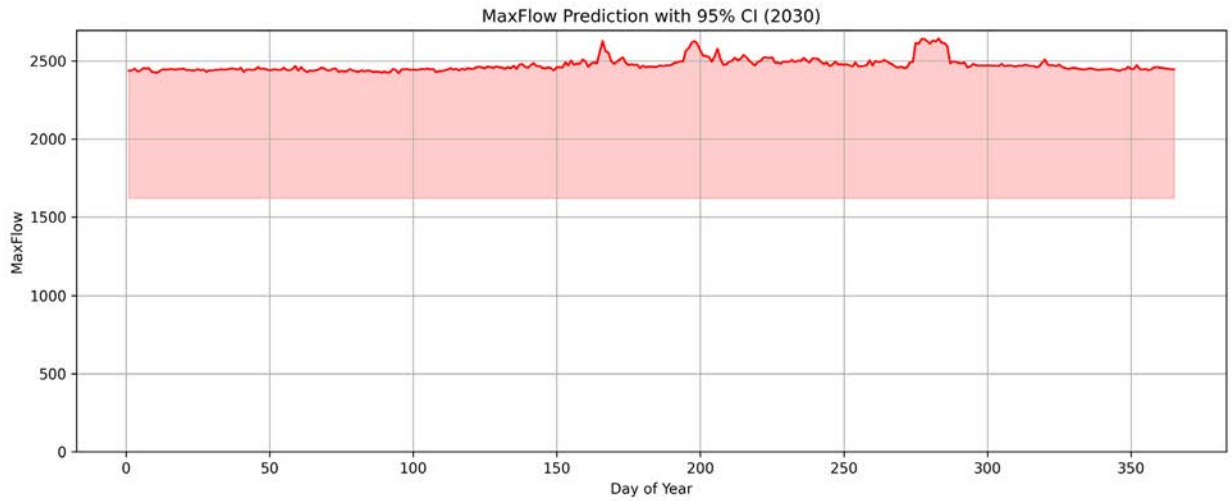


Figure B.7. Projected 2030 maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Manitoba and MISO.

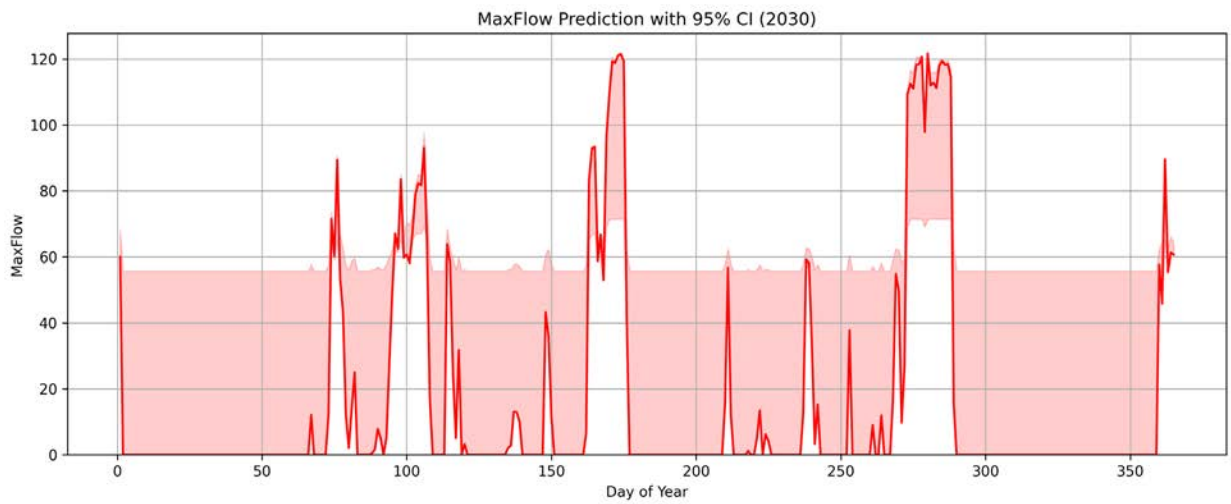


Figure B.8. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and MISO West.

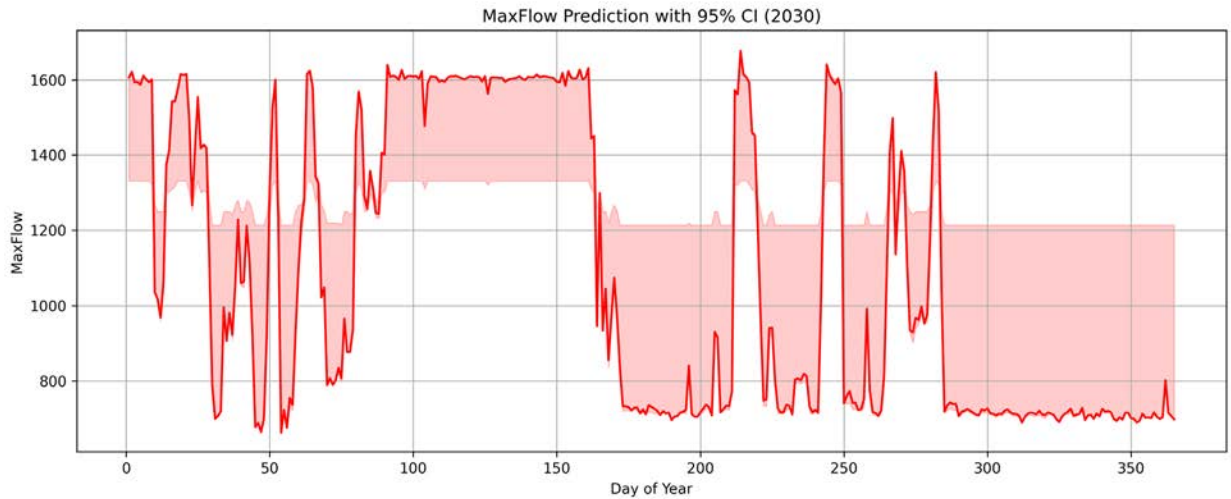


Figure B.9. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and MISO East.

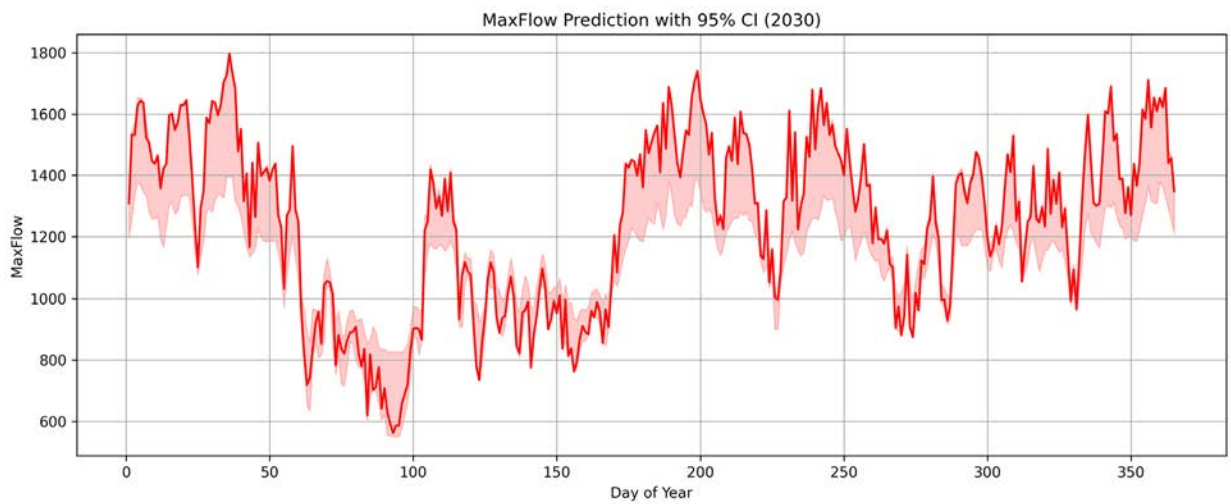


Figure B.10. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and New York.

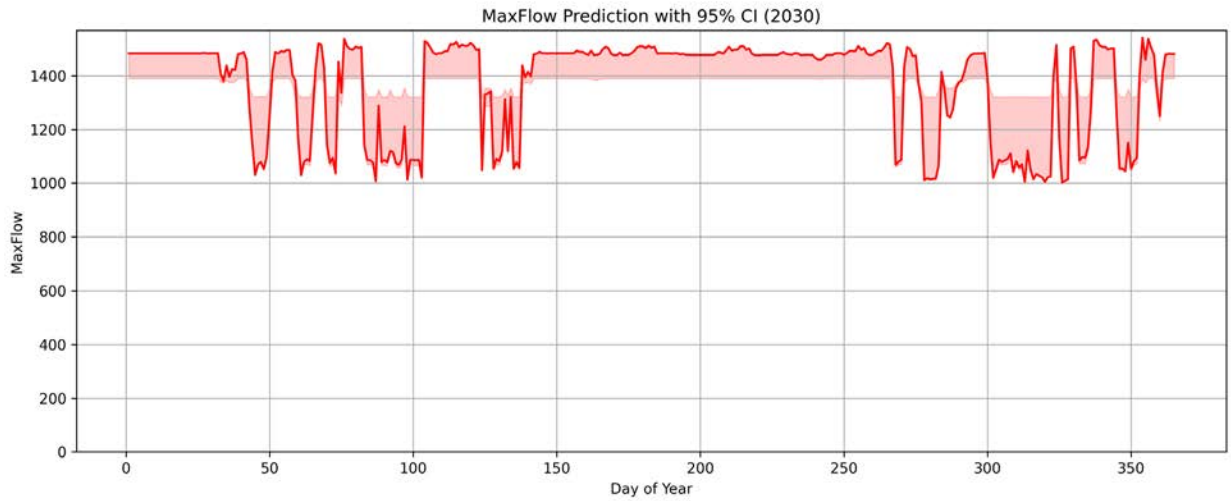


Figure B.11. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Quebec and New York.

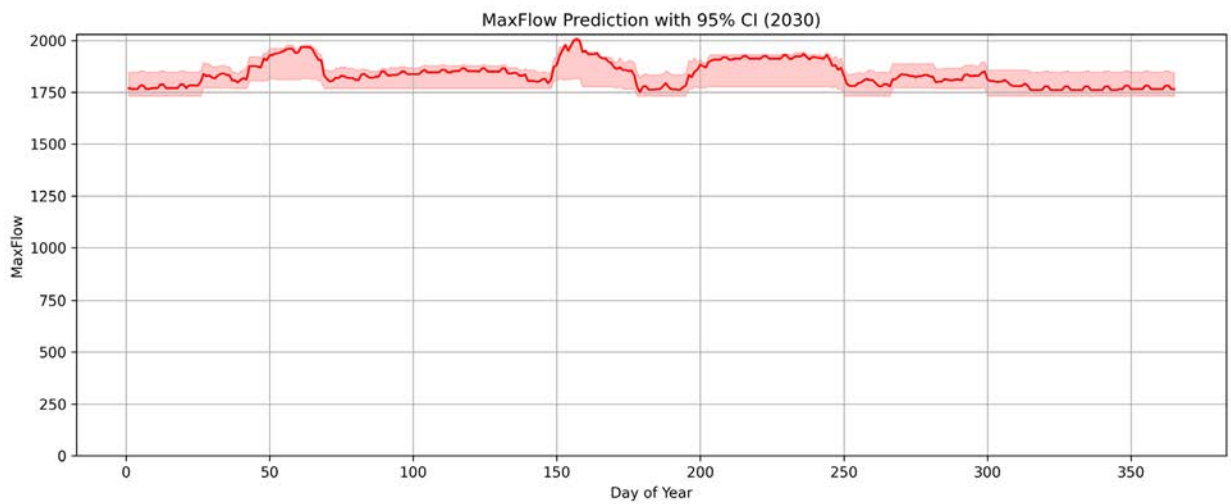


Figure B.12. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Quebec and New England.

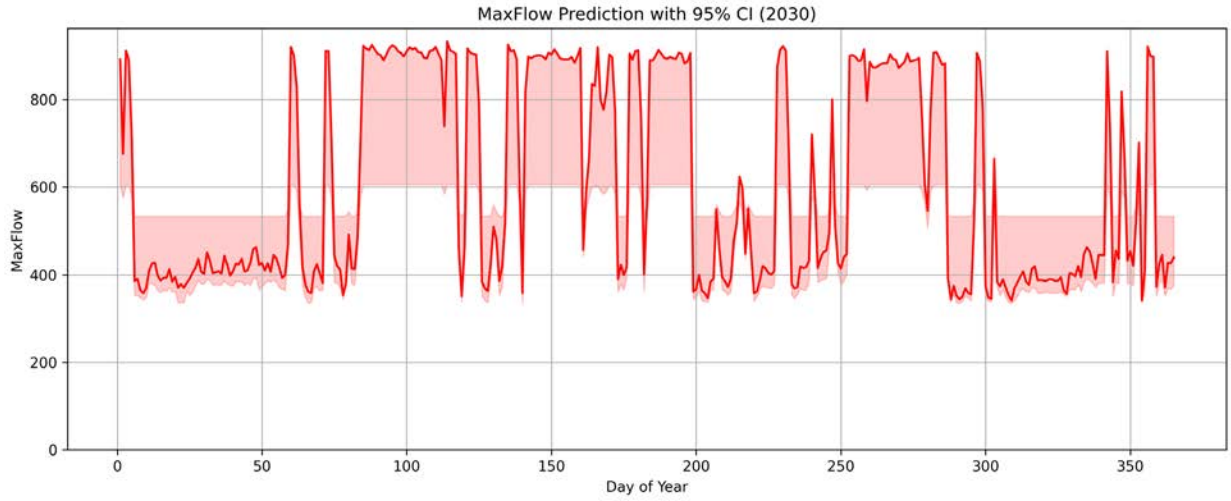


Figure B.13. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between New Brunswick and New England.

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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.

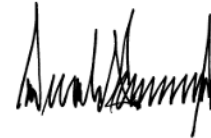
Sec. 4. General Provisions. (a) Nothing in this order shall be construed to impair or otherwise affect:

(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

Attachment S

State AG Request For Rehearing of DOE Report
Aug 6 2025

BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

In re: Resource Adequacy Report: Evaluating
the Reliability and Security of the United
States Electric Grid, July 2025

Submitted via e-mail to:
AskCR@hq.doe.gov
August 6, 2025

**Motion to Intervene and Protective Request for Rehearing by the Attorneys General of
Maryland, Washington, Illinois, Michigan, Minnesota, Arizona, Colorado, Connecticut,
and New York**

The Attorneys General of Maryland, Washington, Illinois, Michigan, Minnesota, Arizona, Colorado, Connecticut, and New York (“the States”) make this filing to raise our concerns with the Department of Energy’s (“Department” or “DOE”) report titled *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, published July 7, 2025 (“Report”),¹ and request rehearing of the same.

Given that DOE has not yet applied the report to issue future emergency orders, the States do not concede that the Federal Power Act requires the States to request rehearing at this time.² Still, the States acknowledge that President Trump instructed DOE to use the methodology in this report as part of a “protocol” to issue orders pursuant to Section 202(c) of the Federal Power Act preventing the retirement of power plants identified as critical to reliability in DOE’s report.³ DOE has indicated that it intends to comply with that mandate and use this Report to “guide reliability interventions” and issue Section 202(c) emergency orders.⁴ The States reserve all rights to present these objections, or any other objection or legal challenge to the Report or DOE’s reliance on this report going forward. However, out of an abundance of caution and to preserve their arguments, the States also formally request rehearing of the methodology,

¹ Available at https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29_0.pdf [https://perma.cc/J2XU-2RRJ].

² See 16 U.S.C. § 825l.

³ See Exec. Order No. 14,262, 90 Fed. Reg. 15,521 (Apr. 14, 2025).

⁴ See U.S. DEPT OF ENERGY, *Fact Sheet: The Department of Energy's Resource Adequacy Report Affirms The Energy Emergency Facing The U.S. Power Grid* (2025), https://www.energy.gov/sites/default/files/2025-07/DOE_Fact_Sheet_Grid_Report_July_2025.pdf [https://perma.cc/YLX7-8G7T] (explaining that DOE’s methodology will be used, pursuant to the executive order, “prevent [] generation resources from leaving the bulk-power system”); Press Release, U.S. Dep’t of Energy, Department of Energy Releases Report on Evaluating U.S. Grid Reliability and Security (July 7, 2025), <https://www.energy.gov/articles/department-energy-releases-report-evaluating-us-grid-reliability-and-security> [https://perma.cc/8TEJ-AGH6]. (stating that its “methodology also informs the potential use of DOE’s emergency authority under Section 202(c) of the Federal Power Act”); Report at vi (explaining that DOE’s standard will be used to “guide reliability interventions”), 1 (emphasizing the need for DOE’s “decisive intervention” in energy markets), 10 (analyzing ERCOT because “FPA Section 202(c) allows DOE to issue emergency orders to ERCOT”).

standards, and protocol identified in this Report under Section 313l of the Federal Power Act, 16 U.S.C. § 825l.

This filing details the ways in which the Report is arbitrary and why it would be unlawful to rely on it to justify future Section 202(c) orders. The States also request DOE review the Report independently before it is used in any capacity in order to address the serious errors in the analysis highlighted here.

I. Motion to Intervene

The Attorneys General of Maryland, Washington, Illinois, Michigan, Minnesota, Arizona, Colorado, Connecticut, and New York move to intervene in this proceeding pursuant to Section 313l of the Federal Power Act, 16 U.S.C. § 825l, and request that the Department of Energy grant rehearing of its July 7, 2025 report titled *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*.

Executive Order 14262 and DOE’s own statements alongside the Report’s publication indicate that it will be used to “guide reliability interventions” and justify issuance of emergency orders under Section 202(c) of the Federal Power Act, 16 U.S.C. § 824a(c). The Report is deeply flawed and, if DOE is taken at its word, it will inflict significant harm on our states.

Many of the retiring resources targeted by this report are located in our states. In Washington, for example, the Transalta Centralia coal-fired power plant is scheduled to retire in December 2025. In Colorado, the Craig and Comanche coal-fired power plants are scheduled to retire by the end of the year as well and the state’s remaining coal fired power plants are scheduled to retire by 2031. These retirements have been thoroughly vetted by state and regional authorities and approved only following an extensive examination of cost considerations and reliability impacts.

And even when a source is not located directly in one of our states, the ratepayer impacts of overriding a planned retirement based on the DOE Report will often be felt by our residents. That is because many of these resources operate within regional transmission systems that spread costs across all, or a portion of, their footprint. In MISO, for example, ratepayers across the ISO’s north and central regions are being asked to foot the bill for the continued operation of the J.H. Campbell coal-fired power plant in Michigan pursuant to a Section 202(c) order issued by DOE in May. In just five weeks, complying with that Order has cost the plant’s owner \$29 million.⁵ The order is expected to cost consumers close to \$100 million if it expires on August 21 and is not renewed.⁶

⁵ See CMS Energy Corp., Quarterly Report (Form 10-Q) (Jul. 31, 2025), <https://www.sec.gov/ix?doc=/Archives/edgar/data/0000201533/000081115625000071/cms-20250630.htm>.

⁶ Brian Dabbs, *Coal Plant Ordered to Stay Open Cost \$29M to Run in 5 Weeks*, POLITICO ENERGYWIRE (Aug. 1, 2025), <https://subscriber.politicopro.com/article/eenews/2025/08/01/coal-plant-ordered-to-stay-open-cost-29m-to-run-in-5-weeks-00487542>.

Our states are also harmed when Section 202(c) is used to keep polluting facilities from retiring in upwind locations. Fossil-fuel power plants are large sources of ozone-forming pollution and toxic emissions that contribute to nonattainment of air quality standards in downwind states like Connecticut, New York, and Maryland. Planned retirements have the benefit of reducing this pollution and overriding those state and regional determinations based on the DOE Report will further the harm that downwind states face from upwind sources.

Moreover, the report unlawfully intrudes on the states' authority to regulate generation resources within their borders. Section 201 of the Federal Power Act clearly reserves to the states their traditional authority "over facilities used for the generation of electric energy."⁷ That authority "is a matter that has traditionally rested with the states, and it should continue to rest there."⁸

Both EO 14262 and subsequent statements by DOE make clear that the report will be used to justify Section 202(c) orders going forward.⁹ The States are aggrieved by the report which paints an unrealistic picture of resource adequacy to justify use of DOE emergency authority. Exercising that authority in non-emergency situations will harm ratepayers and the environment and unlawfully infringe on an area of state sovereign authority. Moreover, our states are also purchasers of retail electricity and are directly harmed by the rate impacts from these decisions.

II. Background

a. Resource adequacy is highly regulated at the state and regional levels.

Existing regulatory mechanisms govern both federal requirements for reserve margins and state resource adequacy determinations. Resource adequacy is an integral part of prudent, least-cost, utility planning in every state and region of the country.¹⁰ DOE plays no role in the complex proceedings to determine either reserve margins or specific resource adequacy conclusions. The Report fails to grapple with the complicated task of resource adequacy planning undertaken by state utility offices and regional grid planners across the country, yet these existing procedures are a key part of the alleged resource adequacy conundrum which the DOE Report claims to address.

⁷ 16 U.S.C. § 824(b)(1).

⁸ *Devon Power LLC et al.*, 109 FERC ¶ 61,154, para. 47 (Nov. 8, 2004).

⁹ See U.S. Dep't of Energy, Order No. 202-25-4 (May 30, 2025) [<https://perma.cc/PS3M-6CJA>] [*hereinafter* "Eddystone Order"] (The methodology "will be used to establish a protocol to identify which generation resources within a region are critical to system reliability and prevent identified generation resources from leaving the bulk power system. . . . DOE plans to use [the July 7] methodology to further evaluate Eddystone Units 3 and 4.").

¹⁰ See SYNAPSE ENERGY ECONOMICS & LAWRENCE BERKELEY NATIONAL LABORATORY, BEST PRACTICES IN INTEGRATED RESOURCE PLANNING 1-2 (Nov. 2024), https://www.synapse-energy.com/sites/default/files/IRP_Best_Practices_2024_Synapse_LBNL_24-061_1.pdf [<https://perma.cc/D68F-WHWQ>].

i. States directly regulate resources to ensure an adequate supply of electricity.

Most states rely on resource planning processes to ensure that adequate generation is available to meet projected demand. While some states have largely delegated this authority to the regional grid operators and rely on market-based mechanisms to ensure future demand is met, it is ultimately the state that retains regulatory authority over generation resources.¹¹ These state processes are transparent and iterative, relying on technical and expert analysis to ensure that adequate resources are procured in a prudent manner. The States describe just a few of the mechanisms at play in our jurisdictions as relevant examples below.

1. Arizona

Arizona, like other states, regulates the power generation, transmission, and distribution needs of the electric grid to ensure resource adequacy and reliability. This regulatory authority is established in the State’s constitution. The Arizona Constitution grants the Arizona Corporation Commission (“ACC”) broad authority to regulate public service corporations, including electric utilities.¹² The Arizona Constitution also empowers the ACC to set just and reasonable classifications, rates, and charges, as well as to make and enforce rules, regulations, and orders for the governance of utilities. This constitutional authority underpins the ACC's ability to establish requirements for resource planning and grid reliability.¹³

The ACC has reliability requirements in its Resource Planning and Procurement (“RPP”) rules.¹⁴ The ACC’s RPP rules require load-serving entities to file and seek acknowledgement of their prospective, 15-year resource plans every three years, which include projected data for generating units and power supply systems, capital costs, environmental impacts, and cost analyses.

The most recent version of Integrated Resource Plans was authorized by the ACC on October 21, 2024,¹⁵ which approved the power generation, transmission, and distribution acquisition plans that were submitted by Arizona Public Service,¹⁶ Tucson Electric Power,¹⁷ and UNS Electric.¹⁸ The ACC requires similar data from its electric cooperatives in order to improve

¹¹ 16 U.S.C. § 824(b)(1).

¹² ARIZ. CONST. art. 15, § 3.

¹³ *Id.*

¹⁴ A.A.C. R14-2-701.

¹⁵ ACC Decision No. 79589, <https://docket.images.azcc.gov/0000212120.pdf?i=1754080707112>.

¹⁶ ARIZONA PUBLIC SERVICE, *2023 Integrated Resource Plan* (Nov. 1, 2023), <https://docket.images.azcc.gov/E000031965.pdf?i=1754080707112>.

¹⁷ TUCSON ELECTRIC POWER, *Tucson Electric Power 2024 Integrated Resource Plan* (Nov. 1, 2023), <https://docket.images.azcc.gov/E000031960.pdf?i=1754080707112>.

¹⁸ UNS ELECTRIC, *UNS Electric 2023 Integrated Resource Plan* (Nov. 1, 2023), <https://docket.images.azcc.gov/E000031961.pdf?i=1754080707112>.

grid performance and reliability in rural areas of the state.¹⁹ The decision requires technology-neutral portfolio methodologies, annual load forecast accuracy reports, and analysis of coal-fired power plant retirement timelines to enhance reliability, building on existing triannual utility analyses. It also requires sharing modeling data with stakeholders.

While one major utility in Arizona, the Salt River Project, is not subject to the ACC’s jurisdiction, it has adopted its own planning and goal-setting requirements, referred to as the Integrated System Plan.²⁰

2. New York

The New York Independent System Operator (“NYISO”) plays a significant role in safeguarding electric grid reliability while supporting the clean energy transition.²¹ As part of its biennial reliability planning process, NYISO first conducts a Reliability Needs Assessment, which examines whether New York’s power grid will have enough generation, storage, and transmission capacity to meet demand over the next ten years.²² Specifically, the Assessment uses probabilistic simulations to evaluate whether New York meets the Loss of Load Expectation (LOLE) criterion of not more than 0.1 event-days/year (equivalent to one day in ten years), which is the standard reliability criterion used by the New York State Reliability Council and the Northeast Power Coordinating Council.²³ The Assessment also evaluates how New York’s environmental and energy laws—such as the Climate Leadership and Community Protection Act, which requires 100% zero-emission electricity by 2040—will affect grid reliability, especially as fossil fuel-fired power plants retire, and electricity demand increases due to building electrification and the continued growth of the electric vehicle market.²⁴

Following the Reliability Needs Assessment, NYISO completes the biennial planning process by issuing a Comprehensive Reliability Plan that documents the plans for a reliable electric grid over the same ten years.²⁵ The Comprehensive Reliability Plan provides solutions to any shortfalls identified in the Reliability Needs Assessment, such as accelerating battery deployment, deferring certain retirements, upgrading transmission lines, or increasing demand-side participation.²⁶ While the 2022 Reliability Needs Assessment did not identify any actionable

¹⁹ ARIZONA ELECTRIC POWER COOPERATIVE, *Demand-and Supply-Side Data Filing* (Apr. 1, 2025), <https://docket.images.azcc.gov/E000042810.pdf?i=1753996193952>.

²⁰ SALT RIVER PROJECT, *Integrated System Plan* (Apr. 1, 2025), <https://www.srpnet.com/grid-water-management/future-planning/integrated-system-plan>.

²¹ *See About Us*, NYISO, <https://www.nyiso.com/about-us>.

²² *See* NYISO, 2024 RELIABILITY NEEDS ASSESSMENT (Nov. 19, 2024), <https://www.nyiso.com/documents/20142/2248793/2024-RNA-Report.pdf>.

²³ *Id.* at 41.

²⁴ *Id.* at 23-24 fig. 13.

²⁵ *See* NYISO, 2023–2032 COMPREHENSIVE RELIABILITY PLAN (Nov. 28, 2023), <https://www.nyiso.com/documents/20142/2248481/2023-2032-Comprehensive-Reliability-Plan.pdf> (following the 2022 RNA and incorporating finding and solutions from the quarterly short term reliability process).

²⁶ *See id.*

reliability shortfalls, the 2023–2032 Comprehensive Reliability Plan nonetheless provided a forward-looking analysis that evaluated key risk factors related to reliability, including delays in major transmission projects, winter peaking and gas shortage risks, and extreme weather.²⁷

In parallel with the biennial reliability planning process, as of 2019, NYISO also conducts a quarterly short-term reliability (“STAR”) process to identify reliability needs that may arise over the next five years due to various changes in the grid, such as generator deactivations, revised transmission plans, or updated electricity demand.²⁸ For example, NYISO’s Quarter 2 2023 STAR report, published on July 14, 2023, identified the potential for electricity supply shortfalls in New York City beginning in the summer 2025 as a result of the New York State Department of Environmental Conservation’s “Peaker Rule,” which seeks to reduce nitrogen oxide (NO_x) emissions from simple-cycle combustion turbines that supply backup generation during peak demand.²⁹ Following this STAR report, NYISO sought proposed solutions from market participants and ultimately exercised its authority under the Peaker Rule to require specific peaker units to remain operational until long-term solutions—such as the Champlain Hudson Power Express line, scheduled to enter service in spring 2026, bringing 1,250 MW of hydropower to New York City—could come online.³⁰ NYISO incorporates any needs or shortfalls identified in the STAR process into its biennial reliability planning process.³¹

3. Connecticut

Connecticut General Statutes § 16a-3a requires that the Department of Energy and Environmental Protection (“DEEP”) prepare an Integrated Resource Plan (“IRP”). An IRP is composed of an assessment of the future electric needs and a plan to meet those future needs. It is “integrated” in that it looks at both demand side (conservation, energy efficiency, etc.) resources as well as the more traditional supply side (generation/power plants, transmission lines, etc.) resources in making its recommendations on how best to meet future electric energy needs in the state. Connecticut’s current IRP was completed in 2020 and updated in 2022. DEEP is currently developing the 2025 IRP, which involves planning for the next ten years.

²⁷ *Id.* at 48-67.

²⁸ See *Short-Term Reliability Process*, NYISO, <https://www.nyiso.com/short-term-reliability-process> (last visited July 28, 2025); *Reliability Planning Process and Declaring a Reliability Need: Next Steps*, NYISO (July 14, 2023), <https://www.nyiso.com/-/reliability-planning-process-and-declaring-a-reliability-need-next-steps>.

²⁹ NYISO, *Short-Term Assessment of Reliability: 2023 Quarter 2* (July 14, 2023), <https://www.nyiso.com/documents/20142/16004172/2023-Q2-STAR-Report-Final.pdf/5671e9f7-e996-653a-6a0e-9e12d2e41740>.

³⁰ Press Release, NYISO, *NYISO Identifies Solution to Solve New York City Reliability Need* (Nov. 20, 2023), <https://www.nyiso.com/-/press-release-%7C-nyiso-identifies-solution-to-solve-new-york-city-reliability-need>.

³¹ See NYISO, 2023–2032 COMPREHENSIVE RELIABILITY PLAN, *supra* note 25, at 30–32.

4. Colorado

Colorado regulations require every investor-owned retail electric utility and wholesale electric generation and transmission cooperative operating in the state to file an energy resource plan (“ERP”) with the Public Utilities Commission (“PUC”) every four years.³² ERPs must contain electric demand and energy forecasts, evaluation of existing resources, an assessment of planning reserve margins and contingency plans for the acquisition of additional resources.³³ If an ERP includes retirement of an existing coal-fired generating facility, detailed workforce transition and community assistance plans must be filed.³⁴

The planning process includes a reserve margin to meet a 0.1 days per year loss of load expectation standard.³⁵ Utilities use this reserve margin to propose additional generation for the planning period, where necessary. Those proposals are vetted through extensive stakeholder input and consideration by the Colorado PUC and the additional generation must satisfy availability and dispatchability criteria.³⁶ And where generation needs arise outside of the four-year ERP process, interim ERPs and applications for certificates of public convenience and necessity can be filed to meet those needs.³⁷ These proceedings are transparent and iterative and conducted with technical and expert analysis of grid conditions and ratepayer impacts.

5. Illinois

Illinois ratepayers are served by two Regional Transmission Organizations (“RTO”), Midcontinent Independent System Operator, Inc. (“MISO”) and PJM Interconnection, L.L.C. (“PJM”). Central and Southern Illinois are encompassed by MISO Local Resource Zone 4 and a small portion of Northwest Illinois is included in MISO Local Resource Zone 1.³⁸ The service area of Commonwealth Edison Company, the load serving entity for Illinois electricity customers in Northern Illinois, is encompassed by PJM’s ComEd Zone.³⁹ The Illinois Attorney General’s office represents Illinois ratepayers who have a significant interest in resource adequacy and maintaining reliable service at least possible cost that is materially affected by the outcome of this proceeding.

³² 4 COLO. CODE REGS. § 723-3-3603(a).

³³ 4 COLO. CODE REGS. § 723-3-3604(b-f).

³⁴ COLO. REV. STAT. § 40-2-125.5(4)(a)(VII).

³⁵ See Colo. Pub. Utils. Comm’n Proceeding No. 24A-0422E, HE 109 and HE 109 ZM-1; Colo. Pub. Utils. Comm’n Proceeding No. 21A-0141E, Hrg. Exh. 115, pp. 8-10.

³⁶ COLO. REV. STAT. § 40-2-125.5 (4)(d)(II).

³⁷ *Id.*

³⁸ See MISO Tariff, Attachment VV, Map of Local Resource Zone Boundaries, https://docs.misoenergy.org/miso12-legalcontent/Attachment_VV_-_MAP_of_Local_Resource_Zone_Boundaries.pdf.

³⁹ See MISO Tariff, Attachment VV, Map of Local Resource Zone Boundaries, https://docs.misoenergy.org/miso12-legalcontent/Attachment_VV_-_MAP_of_Local_Resource_Zone_Boundaries.pdf.

6. Washington

Washington electric utilities file clean energy implementation plans to the Washington Utilities and Transportation Commission once every four years with a biennial update filing at the midway point of every plan.⁴⁰ They also file long term integrated resource plans every four years.⁴¹ For investor-owned utilities, if an integrated resource plan identifies a resource need within the next four years, the utility must file a request for proposal with the Commission for approval.⁴²

7. Michigan

In Michigan, ratepayers are served primarily by MISO, with a smaller portion included within PJM. In MISO, the regulation of resource adequacy planning has both a state and federal aspect. MISO member states have a capacity obligation under the MISO tariff. MISO's resource adequacy requirements, however, are designed to be complementary to the primary role of the states in ensuring resource adequacy.⁴³ In Michigan, the investment decisions of utilities are regulated by the Michigan Public Service Commission ("MI PSC"). Through Michigan's state Integrated Resource Planning process, the MI PSC exercises regulatory authority over utilities in order to ensure that the utilities obtain the amounts of capacity they need to meet their obligations under the MISO tariff, and that they do so at the best value to ratepayers, and with a composition of resources that otherwise complies with state law, including environmental requirements.

Michigan's IRP statute requires electric utilities whose rates are regulated by the MI PSC to periodically file an integrated resource plan. The IRP is a projection of the utility's load obligations and a plan to meet those obligations.⁴⁴ The IRP statute directs the MI PSC to approve

⁴⁰ See WASH. REV. CODE § 19.405.060; WASH. ADMIN. CODE § 480-100-640, -645; *see also* WASH. UTILS. AND TRANSP. COMM'N, *Clean Energy Implementation Plans*, <https://www.utc.wa.gov/regulated-industries/utilities/energy/conservation-and-renewable-energy-overview/clean-energy-transformation-act/clean-energy-implementation-plans-ceips>.

⁴¹ See WASH. REV. CODE § 19.280.040 to 050; WASH. ADMIN. CODE § 480-100-620, -625; *see also* WASH. UTILS. AND TRANSP. COMM'N, *Integrated Resource Plans*, <https://www.utc.wa.gov/integrated-resource-plans-irps>.

⁴² See WASH. ADMIN. CODE § 480-107-009(2), -017.

⁴³ *Midcontinent Indep. Sys. Operator, Inc.*, 170 FERC ¶ 61,215, 62,606 at P 13 (2020) ("approximately 90% of the load in MISO is served by vertically integrated LSEs, the vast majority of which are subject to state integrated resource planning processes. To accommodate the make-up of the MISO's footprint, MISO's proposed Tariff provisions accepted in the February 2018 Order provide that its resource adequacy requirements "are complementary to the reliability mechanisms of the states and the Regional Entities ... within the [MISO] region."); *see also id.* ("MISO's proposed Tariff language explains that the resource adequacy requirements 'are not intended to and shall not in any way affect state actions over entities under the states' jurisdiction.' In other words, unlike the centralized capacity constructs used in the Eastern RTOs/ISOs, MISO's Auction is not—and has never been—the primary mechanism for its [Load Serving Entities] to procure capacity."); *Midwest Indep. Transmission Sys. Operator, Inc.*, 119 FERC ¶ 61,311, 62,722 at P 75 (2007) ("From the beginning . . . the Commission has recognized the role that state resource planning plays in managing the resource adequacy of [MISO]").

⁴⁴ MICH. COMP. LAWS § 460.6t(3).

a plan if the MI PSC determines that it “represents the most reasonable and prudent means of meeting the electric utility’s energy and capacity needs.”⁴⁵ To make that decision, the statute instructs the MI PSC to consider whether the IRP appropriately balances seven statutory factors: (i) resource adequacy and capacity to serve anticipated peak electric load, applicable planning reserve margin, and local clearing requirement; (ii) compliance with applicable state and federal environmental regulations; (iii) competitive pricing; (iv) reliability; (v) commodity price risks; (vi) diversity of generation supply; and (vii) whether proposed levels of peak load reduction and energy waste reduction are reasonable and cost effective.⁴⁶

The IRP statute also directs the MI PSC to establish – among other things – computer modeling scenarios that must be used to analyze the costs of possible plans in an IRP, including costs associated with plant retirement dates.⁴⁷ In Consumers Energy’s 2021 IRP, for example, the company conducted modeling that compared other possible retirement dates of its J.H. Campbell coal-fired power plant to a 2025 retirement and concluded that the most cost-effective retirement date was 2025.

8. Minnesota

Since 1991, Minnesota law has required each public utility to propose a set of resource options that the utility could use to meet the electricity service needs of its customers over a forecast period of 15 years.⁴⁸ The resource options include using, refurbishing and constructing utility plant and equipment, buying power generated by other entities, controlling customer loads, and implementing customer energy conservation. The Minnesota Public Utilities Commission (“Minnesota Commission”) evaluates the plan’s ability to ensure reliability of utility service, keep customer’s bills and utility rates as low as practicable, minimize adverse socioeconomic effects and adverse effects on the environment, and limit risk.⁴⁹ The Commission uses an extensive notice and comment process in which the utilities and stakeholders evaluate detailed modeling of demand and various resource costs. The Minnesota Commission may approve, reject or modify utility resource plans.⁵⁰ In the most recent resource plan for Minnesota’s largest utility, the Minnesota Commission approved including in the resource plan a new natural-gas fired 420 MW combustion turbine plant to address peak load.⁵¹

⁴⁵ MICH. COMP. LAWS § 460.6t(8)(a).

⁴⁶ *Id.*

⁴⁷ MICH. COMP. LAWS § 460.6t(1).

⁴⁸ MINN. STAT. § 216B.2422; MINN. R. ch. 7843; *see also Electric Integrated Resource Planning (IRP)*, MINN. PUB. UTILS. COMM’N, <https://mn.gov/puc/activities/economic-analysis/planning/irp/> (last accessed Aug. 6, 2025).

⁴⁹ MINN. R. 7843.0600, subp. 3.

⁵⁰ MINN. STAT. § 216B.2422.

⁵¹ MINN. PUB. UTILS. COMM’N, Dkt. No. E-002/RP-24-67; E-002/CN-23-212, Order Approving Settlement Agreement With Modifications (Apr. 21, 2025), <https://www.edockets.state.mn.us/documents/%7B30F45996-0000-CF1F-80E3-5E41B2F16918%7D/download?contentSequence=0&rowIndex=3>.

ii. Regional operators establish mechanisms to ensure resource adequacy and grid stability.

State primacy over resource adequacy is further complemented by the regional transmission operators. For example, MISO and PJM both have extensive processes for obtaining resource adequacy and reliability. MISO works collaboratively with its member states to ensure resource adequacy throughout its service area.⁵² MISO ensures there is sufficient generation capacity through forecasting demand growth, assessing existing generation assets, and planning for new generation resources.⁵³ MISO accounts for state Integrated Resource Planning and also operates a capacity auction where utilities and other load-serving entities can procure the necessary generation capacity to meet projected demand. MISO’s capacity market is intended to incentivize the development and maintenance of adequate generation resources.⁵⁴ MISO’s annual Planning Resource Auction (“PRA”) procures sufficient resources and allows market participants to buy and sell capacity via the auction.⁵⁵

Resource adequacy within the PJM footprint is subject to an established, extensive, layered, framework of oversight and regulation. The resource adequacy contribution of each PJM electric generating plant operating is subject to ongoing, technical reviews by PJM, pursuant to its tariff, and in conformity with rules promulgated and periodic grid reliability reviews conducted by Reliability First Corporation and NERC, respectively.⁵⁶ PJM also conducts an auction, its base residual auction (“BRA”), for the procurement of capacity from generating resources.

b. Historic use of 202(c) is limited.

Section 202(c) of the Federal Power Act, 16 U.S.C. § 824a(c), grants the Secretary of Energy the authority to issue orders that require the “temporary connection[]” of power plants and the “generation, delivery, interchange, or transmission of electric energy” in order to address certain emergencies “and serve the public interest.”⁵⁷ The law also effectively waives compliance with “any Federal, State, or local environmental law or regulation” that would conflict with any

⁵² *System Planning*, MISO, https://www.misoenergy.org/meet-miso/about-miso/industry-foundations/grid_planning_basics/ (last visited July 30, 2025).

⁵³ *Id.*

⁵⁴ *Id.*

⁵⁵ *Resource Adequacy*, MISO, <https://www.misoenergy.org/planning/resource-adequacy2/resource-adequacy/#t=10&p=0&s=FileName&sd=desc> (last visited July 30, 2025).

⁵⁶ *See, e.g., North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh’g & compliance*, 117 FERC ¶ 61,126 (2006), *aff’d sub nom. Alcoa, Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009); Order No. 748, Final Rule, 134 FERC ¶ 61,213 (2011). FERC approved regional reliability standards applicable to PJM, developed by RFC and submitted to FERC by NERC. *Notice of Proposed Rulemaking on Plan. Res. Adequacy Assessment Reliability Standard*, 133 FERC ¶ 61,066 (2010) (proposed rule for RFC); *Plan. Res. Adequacy Assessment Reliability Standard*, Order No. 747, 134 FERC ¶ 61,212 (2011) (final approval of RFC’s Resource Adequacy Reliability Standard).

⁵⁷ 16 U.S.C. § 824a(c)(1).

party's obligations under such an order, but limits the length of any order that conflicts with a pollution control requirement to 90-days, with extension possible.⁵⁸

That authority originated principally as a wartime power of what was then the Federal Power Commission. Section 202(c) was enacted in 1935, in the leadup to World War II, with the same “emergency” language that exists in the statute today, specifically to guard against energy related shortages that were viewed as hampering national security during World War I.⁵⁹ It was initially used largely to issue “interconnection” orders specifically between utilities at a time when America’s electric grid was more fragmented, monopolized, and less diversified than it is today.⁶⁰ Interconnection was seen as a powerful means to increase grid reliability, but the federal government largely lacked regulatory power over the electric sector at the time.⁶¹ The then-Federal Power Commission did not invoke its emergency authority until the United States entered World War II.⁶² Section 202(c) orders were issued repeatedly during the war, primarily to order interconnection between utilities, but the provision was rarely invoked once the war ended. A number of organizational changes ensued in the decades following the War and the provision’s authority eventually came to rest with the Secretary of Energy.⁶³

From 2000, when the authority of Section 202(c) was “rediscovered” in response to the California Energy Crisis, through 2024, the provision was sparingly invoked to respond to true emergencies to avoid imminent widespread blackouts.⁶⁴ Most 202(c) orders issued during this period involved natural disasters or other acute power outages.⁶⁵ These emergencies included one high-profile incident near the nation’s capital that led to the statute’s 2015 amendment, adding the provisions explicitly waiving environmental liability due to compliance with a Section 202(c) order, leading the statute to read as it does today.⁶⁶ Orders issued during this period were typically of limited duration, lasting for a period of days to weeks.⁶⁷

The typical process for issuing a Section 202(c) order is outlined by DOE implementing regulations at 10 C.F.R. §§ 205.370-379. In the normal course, requests for Section 202(c) orders originate with a grid operator or utility facing an acute and unforeseen emergency that normal processes and demand response mechanisms are incapable of addressing, though they may be issued by the Department unprompted as well.⁶⁸ Applications for Section 202(c) orders made by

⁵⁸ *Id.* at § 824a(c)(3)-(4).

⁵⁹ For a deeper discussion of the history of Section 202(c), see Benjamin Rolsma, *The New Reliability Override*, 57 CONN. L. REV. 789 (2025). *See also id.* at 798-802.

⁶⁰ *Id.* at 802-804.

⁶¹ *Id.* at 801-802.

⁶² *See id.* at 803 n.82 and accompanying text.

⁶³ *Id.* at 803-04; 42 U.S.C. § 7151(b).

⁶⁴ *Id.* at 805-509.

⁶⁵ Rolsma, *supra* note 59, at 805-09, 839-42 tbl.1.

⁶⁶ *Id.* at 806-08 (citing DEP’T OF ENERGY, ORDER NO. 202-05-3 (Dec. 20, 2005)); 16 U.S.C. § 824a(c)(3)-(5).

⁶⁷ *See* Rolsma, *supra* note [x], at 839-42 tbl.1 (chronicling all Section 202(c) orders issued “after dissolution of the Federal Power Commission”).

⁶⁸ *See* 10 C.F.R. § 205.370.

outside entities are to include specific details to “be considered by the DOE in determining that an emergency exists” and the appropriate intervention.⁶⁹ This information is supposed to include “[d]aily peak load and energy requirements for each of the past 30 days and projections for each day of the expected duration of the emergency,” “[a] description of the situation and a discussion of why this is an emergency, ... includ[ing] any contingency plan of the applicant and the current level of implementation,” and “[a] description of efforts made to obtain additional power through voluntary means and the results of such efforts.”⁷⁰ Section 202(c) orders bypass environmental review under NEPA and can waive pollution control requirements that would otherwise apply to the facilities.⁷¹

c. President Trump Declares a National Energy Emergency on his first day in office and subsequently issues EO 14262.

On January 20, 2025, his first day in office, President Trump issued Executive Order 14156 titled “Declaring a National Energy Emergency.”⁷² That unilateral declaration did not provide any factual support for its assertion that emergency conditions had overtaken the electricity grid.⁷³

On April 8, 2025, President Trump issued Executive Order 14262, “Strengthening the Reliability and Security of the United States Electric Grid.”⁷⁴ Section 3(b) of the executive order directs the Secretary of Energy (Secretary) to:

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.⁷⁵

It further requires that the methodology in the Report (Methodology) “be published, along with any analysis it produces, on the Department of Energy’s website within 90 days of the date of this order,” or July 7, 2025.⁷⁶

The Executive Order describes the featured role that the Report will play in future DOE actions. EO 14262 § 3 is titled “Addressing Energy Reliability and Security with Emergency Authority” and § 3(c) directs the Secretary to “establish a process by which the [Methodology],

⁶⁹ 10 C.F.R. § 205.373.

⁷⁰ 10 C.F.R. §§ 205.373(a)-(o).

⁷¹ *See, e.g., Environmental Integrity Project v. DOE*, 471 F. Supp. 3d 132 (D.D.C. 2023).

⁷² 90 Fed. Reg. 8433.

⁷³ *See Id.* (providing no factual support for claimed emergency). Many of the States have since joined litigation challenging that declaration. *See Complaint, Washington v. Trump*, NO. 2:25-cv-00869 (W.D. Wa. May 9, 2025).

⁷⁴ The EO was signed alongside Exec. Order No. 14261, Reinvigorating America’s Beautiful Clean Coal Industry and Amending Executive Order 14241, 90 Fed. Reg. 15517 (Apr. 8, 2025), at a White House event with members of the coal industry.

⁷⁵ Exec. Order No. 14262, 90 Fed. Reg. 15521, 15521 (Apr. 8, 2025).

⁷⁶ Exec. Order No. 14262, 90 Fed. Reg. 15521, 15521 (Apr. 8, 2025) (referring to § 3(b)(iii)).

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.”⁷⁷ It indicates the protocol shall “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.”⁷⁸ In short, Executive Order 14262 instructs DOE to publish a methodology by July 7, 2025 that will form the basis for future exercises of its Section 202(c) authority.

d. DOE’s 2025 Emergency Orders Preventing the Retirement of Fossil Fuel Power Plants.

Since January 20, 2025, the U.S. Department of Energy (DOE) has issued five emergency orders under Section 202(c) of the Federal Power Act (FPA), a sharp uptick from the less than one order per year issued on average from 2017-2024.⁷⁹ Three of these orders were largely in line with DOE’s historic Section 202(c) practice – allowing units to modify their operations in response to acute risks to the grid.⁸⁰ However, in late May 2025 DOE issued a pair of Section 202(c) orders requiring facilities that were slated to retire the very next business day to remain on-line. These orders represent a marked shift in how Section 202(c) has historically been used.⁸¹

For example, the orders for the J.H. Campbell Generating Station in Michigan and the Eddystone Plant in Pennsylvania, both previously slated for retirement, cited general concerns about resource adequacy and not any acute emergency. In Michigan, regulators warned that the Campbell order would place upward pressure on ratepayers, particularly in Consumers Energy’s service territory, where decommissioning costs were already being recovered through base rates. One Michigan regulator estimated that the costs of complying with DOE’s order for 90 days would approach \$100 million.⁸² Consumers Energy has since disclosed that continued operation

⁷⁷ Exec. Order No. 14262, 90 Fed. Reg. 15521, 15522 (Apr. 8, 2025) (referring to § 3).

⁷⁸ Exec. Order No. 14262, 90 Fed. Reg. 15521, 15522 (Apr. 8, 2025) (referring to § 3) (emphasis added).

⁷⁹ U.S. DEP’T OF ENERGY, *DOE Issues 202(c) Orders to PREPA for Grid Stability*, <https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority>.

⁸⁰ See Duke Energy Carolinas (Order No. 202-25-5) (allowing increased operations to support grid stability); H.A. Wagner (Order No. 202-25-6) (allowing exceedance of operational limit – but maintained compliance with pollution control requirements – to allow units to respond to demand); PREPA (Order No. 202-25-1) (requiring measures to mitigate outage risks during high load conditions)

⁸¹ U.S. Dep’t of Energy, Order No. 202-25-3 (May 23, 2025), https://www.energy.gov/sites/default/files/2025-05/Midcontinent%20Independent%20System%20Operator%20%28MISO%29%20202%28c%29%20Order_1.pdf [<https://perma.cc/Q7P7-TDTX>] [*hereinafter* “Campbell Order”]; Eddystone Order, *supra* note 9.

⁸² See, e.g., Ella Nilsen, *The Trump Admin Ordered a Coal Power Plant to Stay On Past Retirement. Customers in 15 States Will Foot the Bill*, CNN (June 6, 2025), <https://www.cnn.com/2025/06/06/climate/michigan-coal-plant-energy-cost-wright>.

of the plant in the first five weeks since the Order was issued has resulted in a net financial impact of \$29 million.⁸³

e. DOE Publishes its Methodology and Reliability Standard to Guide Future Section 202(c) “Reliability Interventions.”

On July 7, 2025, DOE published a “Report on Evaluating U.S. Grid Reliability and Security,” which set forth the methodology and reliability standard that the Executive Order had mandated. *See* Report at *vi* (hereinafter, “the Report”). DOE stated the methodology “will be assessed on a regular basis to ensure its usefulness for effective action among industry and government decision-makers across the United States.” *Id.* Despite this statement, DOE has not explained how or when it will re-assess the methodology and, to date, has not involved the public in the creation of the methodology or offered an opportunity for public comment on the methodology.

i. DOE did not provide public notice or an opportunity for comment on the Report.

Before publishing the Report, DOE provided no public notice or request for comment on methods or reliability standards that DOE was considering. DOE did not consult with the undersigned States or, to the States’ knowledge and belief, consult with any grid operator or other State on appropriate mechanisms to ensure grid reliability and grid reliability issues around the country.⁸⁴ Other than the statements in the Report, DOE has not made the underlying data or models available to allow the public to reproduce or test DOE’s analysis. DOE has not requested public comment on the Report, opened any administrative proceeding to otherwise involve the public in DOE’s methodology, or published the Report in the Federal Register.

DOE has confirmed, consistent with the Executive Order’s mandate, that it will rely on the Report to justify future Section 202(c) orders.⁸⁵ DOE explained in the June 2025 Eddystone Order that it would use the forthcoming Report “to establish a protocol to identify which generation resources within a region are critical to system reliability and prevent identified generation resources from leaving the bulk power system[,]” including potential Section 202(c) orders extending DOE’s Eddystone Order.⁸⁶ DOE also issued the Report with a “Fact Sheet,”

⁸³ *See supra* notes 5-6 and accompanying text; NRDC, *Trump Administration’s DOE Is Forcing Coal Plants to Stay Open. Michigan Is the First Target* (June 16, 2025), <https://www.nrdc.org/bio/derrell-e-slaughter/trump-administrations-doe-forcing-coal-plants-stay-open-michigan-first>.

⁸⁴ *See* Report at *i* (acknowledging lack of data from regional and utility levels).

⁸⁵ *See* Report at *vi* (explaining that DOE’s standard will be used to “guide reliability interventions”), 1 (emphasizing the need for DOE’s “decisive intervention” in energy markets), 10 (analyzing ERCOT because “FPA Section 202(c) allows DOE to issue emergency orders to ERCOT”).

⁸⁶ Eddystone Order, *supra* note 9.

wherein DOE explained that the methodology will be used to “prevent [] generation resources from leaving the bulk-power system.”⁸⁷

ii. DOE’s analysis rests on key assumptions about load growth, retirements, and capacity additions.

The Report’s analysis rests on assumptions about future electricity demand (referred to as “load growth”), anticipated retirements of existing facilities (“retirements”), and future electricity generation sources (referred to as “capacity additions”). DOE made additional assumptions, some explicit and others implicit, which the States have not yet been able to fully analyze or comment on here.⁸⁸

Regarding load growth, DOE assumes 101 Gigawatts (“GW”) of new load will be added to the grid by 2030.⁸⁹ DOE projects that data centers, especially for developing Artificial Intelligence (“AI”), will add 50 GW of that new load, and other demand growth will add 51 GW. DOE appears to assume that data-center load will be “firm,” meaning electricity to meet that demand must be guaranteed at all times.⁹⁰ That is in contrast to “interruptible” load for which supply can be reduced during peak periods.⁹¹ DOE also appears to assume that all the new data centers will connect to the grid, rather than rely on “behind-the-meter” generation and that regulators and grid operators will allow every MW of new load to connect to the grid on a firm basis, even if doing so threatens the grid’s reliability.⁹² Based on these assumptions, DOE projects a 15% increase in load by 2030.⁹³

The Report assumes 51 GW of non-data-center load, purportedly based on the NERC’s 2024 ITCS projections.⁹⁴ DOE does not explain why using projections from a NERC report on inter-regional transmission is reasonable or why those projections are reliable for DOE’s purposes. Additionally, NERC’s 2024 projections likely already include some data center load expectations, as well as policies to encourage the electrification of transportation, heating and cooling, and other energy uses that the Trump Administration has rescinded or is planning to

⁸⁷ U.S. DEP’T OF ENERGY, *Fact Sheet: The Department of Energy’s Resource Adequacy Report Affirms The Energy Emergency Facing The U.S. Power Grid* (2025), https://www.energy.gov/sites/default/files/2025-07/DOE_Fact_Sheet_Grid_Report_July_2025.pdf [<https://perma.cc/YLX7-8G7T>]; *see also* Press Release, U.S. Dep’t of Energy, Department of Energy Releases Report on Evaluating U.S. Grid Reliability and Security (July 7, 2025), <https://www.energy.gov/articles/department-energy-releases-report-evaluating-us-grid-reliability-and-security> [<https://perma.cc/8TEJ-AGH6>] (stating that its “methodology also informs the potential use of DOE’s emergency authority under Section 202(c) of the Federal Power Act”).

⁸⁸ *See generally* Report at 10-19.

⁸⁹ Report at 2-3.

⁹⁰ Report at 18.

⁹¹ *Id.*

⁹² *See id.* at 2-3, 15-18.

⁹³ *See* Ric O’Connell, *GridLab Analysis: Department of Energy Resource Adequacy Report* (July 11, 2025), <https://gridlab.org/gridlab-analysis-department-of-energy-resource-adequacy-report/> [<https://perma.cc/GN56-VLNA>].

⁹⁴ *See* Report at 11.

rescind.⁹⁵ DOE apparently did not account for shifting electrification policies in its load projections.

Regarding retirements, DOE assumed 104 GW of “firm capacity” retirements by 2030, roughly three-quarters from coal-fired power plants and one-quarter gas plants.⁹⁶ *Id.* at 5; see also Report at 3, 12-13, A1-A8. DOE included approximately 50 GW of “confirmed retirements,” retirements that have been formally recognized by system operators as having started the official retirement process and are assumed to retire on their expected date.⁹⁷ DOE also included approximately 50 GW of “announced retirements,” which are generators that have publicly stated retirement plans but not formally notified system operators or initiated the retirement process.⁹⁸

Regarding capacity additions, DOE took a more conservative approach. Rather than including all announced projects, DOE assumed “that only projects considered very mature in the development pipeline—such as those with signed interconnection agreements—will be built.” Report at A-5. These projects, known as Tier 1 resources, are by their very nature likely to be built in the short term. As a result, DOE assumed “minimal capacity additions beyond 2026.” *Id.* In addition, DOE does not appear to have modeled new transmission projects, despite their grid reliability benefits.

The Report’s assumptions about load growth and electricity supply differ significantly from other forecasts.⁹⁹ As one grid reliability expert commented, DOE’s report “used aggressive assumptions regarding load growth and retirements, but conservative assumptions about how much new generation capacity will be added, even assuming no new resources after 2026.”¹⁰⁰ For example, DOE assumed 15% load growth by 2030, but the U.S. Energy Information Agency recently assumed just 6% in their “high” growth” case.¹⁰¹ Other differences with the Energy

⁹⁵ See NERC, 2024 Long Term Reliability Assessment Report 8 (July 15, 2025), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf [https://perma.cc/NMP4-KRN5] (discussing how “the continued adoption of electric vehicles and heat pumps is a substantial driver for demand around North America”).

⁹⁶ Report at 5.

⁹⁷ *Id.* at 12; see also O’Connell, *supra* note 93.

⁹⁸ Report at 12.

⁹⁹ Report at 2 (noting that demand forecasts vary widely).

¹⁰⁰ O’Connell, *supra* note 93.

¹⁰¹ U.S. Energy Information Administration, Form EIA-860 (June 11, 2025) <https://www.eia.gov/electricity/data/eia860/>.

Information Agency forecasts are described in the chart below:¹⁰²

DOE Report Assumptions vs. U.S. Energy Information Administration Data:

	DOE Report	EIA 860
Load growth:	101 GW	N/A
Capacity Additions	209 GW	200 GW
Gas Capacity Additions	22 GW	35 GW
Battery Capacity Additions	31 GW	53 GW
Retirements	104 GW	52 GW

The Report also does not address actions already being taken by states, utilities, and regional grid operators to meet increased load growth or how markets are already responding to increasing demand. As GridLab explained in its analysis:

Markets and utilities have already responded with plans to add new capacity and fast track new resources. These include PJM’s Reliability Resource Initiative, which plans on adding 11 GW of new firm resources by 2030. SPP and MISO both have proposals at FERC (called ERAS) that could add another 30 GW of firm resources. Those three regional efforts alone would add roughly twice what the DOE assumed for the entire nation.¹⁰³

iii. Based on these assumptions and DOE’s resource adequacy standard, DOE concluded intervention in electricity markets is needed to prevent outages.

DOE then adopted a novel “resource adequacy standard,” using a combination of non-traditional and non-standardized metrics (“Loss of Load Hours” and “Normalized Unserved Energy”).¹⁰⁴ DOE selected the target to be achieved with each metric.¹⁰⁵

DOE did not define what energy sources it considered “firm” capacity or why only those sources provide the necessary attributes for grid reliability. DOE’s usage of the term in the report suggests that only coal or gas power plants count as “firm” capacity and excluded other sources that could provide similar, greater, or different levels of reliability (like batteries or transmission) from its analysis.¹⁰⁶

¹⁰² O’Connell, *supra* note 93.

¹⁰³ *Id.*

¹⁰⁴ Report at 3-4.

¹⁰⁵ *Id.*

¹⁰⁶ *See, e.g., id.* at 1, 32, 37.

DOE portrayed three scenarios in an attempt to assess the impact of planned retirements on resource adequacy in 2030.¹⁰⁷ The first scenario is “Plant Closures,” which assumes that announced retirements and capacity additions “in the final stages for connection” that are “either under construction or ha[ve] received approved planning requirements” will occur.¹⁰⁸ The second scenario is “No Plant Closures,” which has the same assumption about additions as the “Plant Closures” scenario but assumes no retirements.¹⁰⁹ The third scenario is “Required Build” which uses the “Plant Closures” scenario’s assumptions about retirements and then artificially adds enough hypothetical perfect capacity to the system to meet DOE’s new reliability standard.¹¹⁰ Perfect capacity is hypothetical capacity that experiences no outages and is used in the modeling “to avoid the complex decision of selecting specific generation technologies, as that is ultimately an optimization of reliability against cost considerations.”¹¹¹

DOE then concluded, based on the above assumptions, the risk of power outages in 2030 would be 100 times higher in 2030 than it is today.¹¹² DOE concluded that “decisive intervention” and “robust and rapid reforms” are necessary to avoid this result and to accommodate “projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation.”¹¹³ Numerous grid experts have commented on the shortcomings of this approach.¹¹⁴

III. Statement of Issues and Specification of Errors.

1. The Report is arbitrary, capricious, contrary to law, and unsupported by substantial evidence in violation of the Administrative Procedure Act and Federal Power Act because it suffers from numerous analytical, mathematical, and empirical flaws, including but not limited to the following:
 - a. DOE relies on key assumptions about load growth, retirements, and capacity additions that are unreasonable and unsupported by evidence or logic.

¹⁰⁷ *Id.* at 3, 5.

¹⁰⁸ *Id.* at 4-5.

¹⁰⁹ *Id.*

¹¹⁰ *Id.*

¹¹¹ *Id.* at 5.

¹¹² *Id.* at 1.

¹¹³ *Id.*

¹¹⁴ See, e.g., Jeff St. John, *Critics Fear Trump Will Use Flawed DOE Report to Push Pro-Coal Agenda*, CANARY MEDIA (July 14, 2025), <https://www.canarymedia.com/articles/fossil-fuels/trump-doe-report-open-coal-plants> [https://perma.cc/2T7L-3FWX]; Matthias Fripp & Brendan Pierpont, *Energy Department’s Flawed Grid Study Props Up Expensive, Zombie Power Plants*, UTILITYDIVE (July 24, 2025), <https://www.utilitydive.com/news/doe-grid-reliability-study-zombie-power-plants/753596/> [https://perma.cc/QH3V-KM5R]; INST. FOR POL’Y INTEGRITY, ENOUGH ENERGY: A REVIEW OF DOE’S RESOURCE ADEQUACY METHODOLOGY (July 2025), https://policyintegrity.org/files/publications/IPI_EnoughEnergy_FinalReport.pdf [https://perma.cc/WN39-K9LE].

- b. DOE assumes the transmission grid will remain static over the next five years and fails to consider how new transmission projects in development will impact reliability.
- c. DOE fails to define “firm power capacity” or reasonably explain why DOE apparently considers only coal and gas to be “firm power capacity” when other generation sources, energy storage, or transmission could provide similar or greater reliability attributes.
- d. DOE’s assumptions unreasonably presume that the market, grid operators, and state regulators will take no action in the next five years to address load growth or reliability issues, and that no alternative other than preserving aging coal and gas power plants will ensure grid reliability.
- e. DOE’s analysis suffers from mathematical errors, analytical flaws, and lacks sufficient data or regional input. Those flaws are amply described in the attached analysis by the Institute for Policy Integrity and are incorporated and adopted here. *See* IPI Report (attached as Ex. XX).
- f. Although DOE acknowledged that data and input from states and regional entities could improve the analysis, DOE chose not to consult with those entities or seek to obtain that data.
- g. DOE selected non-traditional and non-standardized resource adequacy metrics and targets to be achieved without providing a reasoned explanation for its choices, including why it selected Normalized Unserved Energy (“NUSE”) and Loss of Load Hours (“LOLH”) instead of other possible metrics that would provide different data, an explanation of the costs and benefits of its choices and the target to be achieved, and why a nationwide target is appropriate despite regional differences in the costs and benefits with regard to resource adequacy.
- h. DOE offers no reasonable explanation how the Report could be used to identify “at-risk region[s] and guide reliability interventions” when it arbitrarily relies on geographic groupings that do not match boundaries used by utilities, balancing authority areas, transmission planning regions, regional wholesale markets, NERC regional entities, or NERC reliability coordinators to reliably operate the nation’s electric grid.

These assumptions and omissions work together to arbitrarily tip the scales in favor of finding a resource adequacy risk. *See Motor Vehicles Mfrs. Ass’n v. State Farm*, 463 U.S. 29, 43 (1983); *WildEarth Guardians v. U.S. Bureau of Land Mgmt.*, 870 F.3d 1222, 1237 (10th Cir. 2017); *Nat. Res. Def. Council, Inc. v. Herrington*, 768 F.2d 1355, 1391 (D.C. Cir. 1985); *see also infra* Section 4.a.

- 2. The Report is arbitrary, capricious, contrary to law, and unsupported by substantial evidence in violation of the Administrative Procedure and Federal Power Acts because it pursues an extra-statutory motive of preserving aging and uneconomic fossil fuel

power plants at consumer expense, which contradicts the Federal Power Act’s express goal of preserving just and reasonable rates and preventing undue discrimination or preference. The Administration’s energy actions, when viewed collectively, also demonstrate that DOE has prejudged the outcome of this proceeding and intended its analysis to reach only one result: preventing the retirement of fossil-fueled power plants. *See Dep’t of Com. v. New York*, 588 U.S. 752, 785 (2019); *Gresham v. Azar*, 950 F.3d 93, 104 (D.C. Cir. 2020), *vacated as moot*, *Becerra v. Gresham*, 142 S. Ct. 1665 (2022). *See also infra* Section 4.a.iii-iv.

3. The Report is arbitrary, capricious, contrary to law, and unsupported by substantial evidence in violation of the Administrative Procedure and Federal Power Acts because it purports to guide emergency action under Section 202(c) of the Federal Power Act but does not describe an “emergency” within the meaning of the Federal Power Act or DOE’s implementing regulations. *See* 16 U.S.C. § 824a(c)(1); 10 C.F.R. § 205.371; *Otter Tail Power Co. v. Federal Power Com.*, 429 F.2d 232, 234 (8th Cir. 1970). *See also infra* Section 4.b.
4. The Report is arbitrary, capricious, contrary to law, and unsupported by substantial evidence in violation of the Administrative Procedure and Federal Power Acts because it “fails to consider an important aspect of the problem” and fails to consider reasonable alternatives. Specifically, the Report ignores alternatives, or in some cases actively prevents viable alternatives with no explanation, such as expanding interregional transmission, batteries, renewable energy, incorporating data centers flexibly into load, and the existing resource adequacy mechanisms that are used by states and regional grid operators to assess reliability and respond to resource adequacy needs. *See State Farm*, 463 U.S. at 43. *See also infra* Section 4.a. (arbitrary and capricious) and section 4.c. (existing resource adequacy mechanisms)].
5. The Report is *ultra vires* and contrary to law in violation of the Administrative Procedure and Federal Power Acts because it intrudes upon matters reserved for the States and the Federal Energy Regulatory Commission. DOE does not possess authority to set nationwide resource adequacy standards or regulate sources of electricity generation. *See* 16 U.S.C. § 824b(1); *Whitman v. Am. Trucking Ass’ns, Inc.*, 531 U.S. 457, 468 (2001). *See also infra* Section 4.d.
6. The Report violates the Administrative Procedure Act, 5 U.S.C. 553, because it establishes a legislative rule without first providing public notice and comment. *See Shalala v. Guernsey Mem’l Hosp.*, 514 U.S. 87, 99–100 (1995); *Nat’l Min. Ass’n v. McCarthy*, 758 F.3d 243 (D.C. Cir. 2014); *Children's Health Care v. Centers for Medicare & Medicaid Servs.*, 900 F.3d 1022 (8th Cir. 2018). *See infra* Section 4.e.

7. The Report is arbitrary, capricious, and contrary to law in violation of the Administrative Procedure Act because it allegedly supports issuing Section 202(c) emergency orders based on factors and procedures that conflict and are inconsistent with DOE's existing regulations. *See Emergency Interconnection of Electric Facilities*, 46 Fed. Reg. 39,984 – 39,989 (Aug. 6, 1981); 10 C.F.R. §§ 205.371 *et seq.* *See infra* Section 4.e.ii.
8. The Report is arbitrary and capricious in violation of the Administrative Procedure Act because DOE failed to acknowledge that its methodology and protocol for issuing Section 202(c) orders is inconsistent with the factors for determining when an emergency exists that DOE's regulations already set out. *See Emergency Interconnection of Electric Facilities*, 46 Fed. Reg. at 39,985; 10 C.F.R. §§ 205.371, 205.373. It is also inconsistent with DOE's previous position that emergency orders are inappropriate for long-term reliability issues and a "utility must solve long-term problems itself." 46 Fed. Reg. at 39,985; *see also* 10 C.F.R. § 205.371. Agencies act arbitrarily when they fail to display awareness that they are changing position and offer good reasons for the change in policy. *See Food & Drug Administration v. Wages & White Lion Invs.*, 604 U.S. ---, 145 S. Ct. 898, 918 (2025); *see also infra* Section 4.e.

IV. Request for Rehearing

a. DOE's Report is Based on Flawed and Arbitrary Assumptions and is Unsupported by Substantial Evidence.

The Report's conclusions rest on critical assumptions about load growth, retirements, and capacity additions, but DOE did not reasonably explain how it arrived at those assumptions or support its choices with substantial evidence. At times, DOE's assumptions are internally inconsistent and arbitrarily tip the scales in favor of finding a need to prevent scheduled retirements. The Report also seems to adopt a definition of "firm capacity" that includes only fossil-fuel power plants, but does not explain why other generation sources or batteries are not also "firm capacity." DOE has also failed to make the data it relied on publicly available – rendering it impossible to fully test DOE's analysis.¹¹⁵

¹¹⁵ Due to the lack of public notice or any consultation or opportunity for involvement in the DOE's development of this report, the States have not had an opportunity to fully analyze DOE's methodology. DOE also has not made the data or models it used publicly available, which would allow the States to critically assess or replicate DOE's analysis and uncover additional flaws in DOE's approach. As such, the States reserve the right to raise additional flaws with DOE's analysis and conclusions at a later date, as they continue to analyze the Report.

Agencies act arbitrarily when they base decisions on key assumptions that are irrational or unsupported.¹¹⁶ Moreover, when agencies use complex models, they must publicly reveal the assumptions and data incorporated into their models and “provide a full analytical defense” of their model.¹¹⁷

i. DOE fails to reasonably explain or support its load growth assumptions

DOE assumes 15% load growth by 2030, half of which DOE assumes will serve new data centers.¹¹⁸ In doing so, DOE presumes – without evidence or a rational explanation – that data center load is firm (i.e., it cannot be interrupted at peak times). That assumption is arbitrary and directly undermined by recent advances in both policy and technology.

Some policymakers are already requiring data centers to be flexible, interruptible load.¹¹⁹ In Texas, for example, a new law grants ERCOT more flexibility to curtail certain data center loads in the event of a grid emergency.¹²⁰ DOE did not grapple with the impact of this law on its underlying assumptions despite the fact that curtailing such load during peak hours “could go a long way towards avoiding the DOE-identified resource adequacy problem” in ERCOT.¹²¹

DOE also ignores the possibility of industry reducing its demand for electricity either as a matter of policy or innovation in this rapidly developing field. NVIDIA, the foremost supplier of hardware for AI data centers, recently announced a new power supply unit that can reduce peak grid demand by up to 30%.¹²² In another recent example, Google agreed to a demand response framework with two utilities that would reduce how much electricity is used by its data centers during peak hours.¹²³

DOE’s reliance on an inflexible assumption for data center load reflects a failure to consider how this rapidly developing industry may adapt to address its significant energy

¹¹⁶ *WildEarth Guardians v. U.S. Bureau of Land Mgmt.*, 870 F.3d 1222, 1237 (10th Cir. 2017); *Hisp. Affs. Project v. Acosta*, 901 F.3d 378, 389 (D.C. Cir. 2018) (noting agencies’ affirmative duty to examine key assumptions underlying their policies).

¹¹⁷ *Nat. Res. Def. Council, Inc. v. Herrington*, 768 F.2d 1355, 1385 (D.C. Cir. 1985); see also *Columbia Falls Aluminum Co. v. EPA*, 139 F.3d 914, 923 (D.C. Cir. 1998).

¹¹⁸ Report at 18.

¹¹⁹ See Ex. D, Nicholas Institute Report at 25; see also Ex. C, IPI Report at 24

¹²⁰ S.B. No. 6 § 4, 89th Legislature (Tex. 2025) (to be enacted at Tex. Util. Code § 39.170); See also Ex. C, IPI Report at 26.

¹²¹ Ex. C., IPI Report at 26.

¹²² Meris Lutz, *NVIDIA addresses AI peak power demand, spikes in new rack-scale systems*, UtilityDive (July 30, 2025), <https://www.utilitydive.com/news/nvidia-rack-scale-system-smooth-ai-power/756279/>.

¹²³ Laila Kearney, *Google agrees to curb power use for AI data centers to ease strain on US grid when demand surges*, Reuters (Aug. 4, 2025), <https://www.reuters.com/sustainability/boards-policy-regulation/google-agrees-curb-power-use-ai-data-centers-ease-strain-us-grid-when-demand-2025-08-04/>.

demand. This renders DOE’s blunt conclusions regarding resource adequacy arbitrary and capricious.¹²⁴

The Report also adopts an unreasonably high estimate of future data center load, arbitrarily claiming it is simply adopting a “midpoint assumption.” Report at 15. DOE admits that there are “wide variations” in estimates of future data center load growth, yet the agency does not appear to have conducted any actual evaluation of those estimates to determine their respective accuracy. DOE must explain why its adoption of an estimated 50 GW load growth is more reliable or likely than other projections. It cannot just pick what it calls a “midpoint” from available studies and move forward. A rational approach would involve projecting future growth under a number of scenarios. Indeed, DOE did not account for a number of factors that temper against aggressive assumptions for future data center load growth. Those factors include the fact that data center developers often make duplicative requests for service; that data center deployment is limited by the availability of chips and processing systems; that data center efficiency may increase in the future as technology develops; and that utilities are incentivized to adopt aggressive load forecasts.¹²⁵

The Report also assumes an additional 51 GW of non-data center load growth. DOE states that it adopted this assumption from NERC’s 2024 ITCS Report. But NERC’s 2024 ITCS Final Report does not contain its own load growth projections.¹²⁶ DOE has not cited which NERC projections it is relying on, what data underlie those projections, or why DOE considers it reliable for purposes of setting a uniform resource adequacy standard and guiding reliability interventions. Moreover, NERC’s forecasts already contain data center load expectations meaning the Report may be double counting projected future demand from data centers.¹²⁷ NERC’s forecasts may also contain other assumptions that are no longer appropriate, such as demand forecasts based on federal incentives to electrify transportation that no longer exist. Additionally, as the Institute for Policy Integrity explains in its report, DOE’s method for distributing load growth across the country is questionable and does not necessarily reflect actual market decisions.¹²⁸

ii. DOE arbitrarily assumes 104 GW of retiring capacity by 2030 but only 22 GW of additions in the same time period.

The Report also assumes the retirement of 104 GW of generating capacity by 2030, an extremely aggressive estimate that cannot withstand any level of scrutiny.¹²⁹ That assumption is inconsistent with the U.S. Energy Information Administration’s data from June 2025 showing

¹²⁴ See Report at 17, 40; see also Ex. C, IPI Report at 26 (“DOE should have considered the possibility that some of the projected data center load would be flexible, especially in ERCOT”).

¹²⁵ See generally Ex. E, London Economics International Report.

¹²⁶ Ex. A, NERC ITCS Report.

¹²⁷ Report at 17.

¹²⁸ See Ex. C, IPI report at 24; see also Ex. E, LEI Report at 10-14 (noting that data centers have many choices where to locate).

¹²⁹ See Report at 5, A-5.

only half of that capacity is actually set for retirement.¹³⁰ This projection is also flawed because it arbitrarily includes announced retirements even though those generators have not formally provided notice of their retirement or initiated the retirement process.¹³¹ Many of these resources have, however, pushed back their actual retirement dates due to changing market conditions and the policies of the current administration.¹³²

At the same time that the Report overestimates the amount of load growth and retirements by 2030, it underestimates capacity additions that can be reasonably expected to come online in that same timeframe. DOE assumes only Tier 1 projects will be built by 2030. Because Tier 1 additions are projects that are either under construction or received approved planning requirements, nearly all will be in service by 2026.¹³³ DOE acknowledged that the Tier 1 assumption “results in minimal capacity additions beyond 2026,” Report at A-5, yet DOE did not explain why that assumption was nonetheless reasonable when forecasting conditions to 2030.

By focusing solely on Tier 1 projects, DOE excludes announced capacity additions or even capacity additions that are seeking approval to interconnect to the grid (NERC “Tier 2” projects).¹³⁴ Excluding capacity that has been requested but has not yet received approval for planning requirements does not make sense for predictions stretching out five years from now. Both common sense and history suggest that at least some of these additions will receive approval in that time.¹³⁵ DOE has thus adopted a view of generator additions that is completely at odds with its projection of generator retirements and together the approach arbitrarily tips the scales in favor of finding a resource adequacy risk.

These assumptions seem to ignore a fundamental property of market dynamics: that supply will respond to rising demand. DOE assumes that generators who have not initiated the retirement process will retire even if remaining in the market would still be economic for them. And DOE assumes that developers will refrain from building any new energy projects from 2027-2030 despite market signals that additional capacity is needed. Those assumptions are unreasonable and render the Report arbitrary and capricious.¹³⁶

¹³⁰ U.S. Energy Information Administration, Form EIA-860 (June 11, 2025)

<https://www.eia.gov/electricity/data/eia860/>.

¹³¹ See Report at 5, A-5.

¹³² Kevin Clark, *Where coal plant retirements are happening – And what could delay them*, Power Engineering (July 14, 2025), <https://www.power-eng.com/coal/plant-decommissioning/where-coal-plants-are-closing-and-what-could-delay-them/>. See also, Joe Schulz, *We Energies will delay Oak Creek coal plant retirement by one year to 2026*, Wisconsin Public Radio (June 26, 2025), <https://www.wpr.org/news/we-energies-delay-oak-creek-coal-plant-retirement-2026>. See also Ex. C, IPI Report at 23-24 (explaining why DOE’s retirement figure likely overstates retirements).

¹³³ NERC, *2024 Long-Term Reliability Assessment* at 22, 136-37 (2024),

https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

¹³⁴ *Id.*

¹³⁵ See also Ex. C, IPI Report at 21-22 (applying historical statistics and data to demonstrate why DOE’s exclusion of Tier 2 additions is unreasonable).

¹³⁶ See Report at 1 (concluding that, based on its model, intervention is needed to ensure a reliable power grid and meet the AI growth requirements).

DOE also arbitrarily excludes new transmission projects from its analysis altogether. Interregional transmission improvements are known to be one of the most cost-effective ways of improving grid reliability.¹³⁷ DOE apparently assumes that the nation’s transmission will remain static over the next five years, despite ongoing planning processes and reforms to increase transmission projects and the well-documented reliability benefits that more transmission can provide.¹³⁸ DOE also appears to undercount the reliability benefit of existing transmission systems in its analysis.¹³⁹ It is nonsensical to ignore the benefits of new transmission when DOE is purportedly seeking to improve the reliability of the electric grid and keep costs affordable for consumers.

iii. DOE’s analysis lacks sufficient regional granularity and suffers from other analytical flaws.

DOE’s analysis also suffers from mathematical errors, analytical flaws, and lacks sufficient data or regional input further highlighting the importance of leaving resource adequacy to the states. DOE itself recognized that the Report’s lack of regional data was a shortcoming that undercut its conclusions. As DOE acknowledges, “[e]ntities 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.”¹⁴⁰ Despite this admission, DOE made no attempt to consult with States or grid operators on reliability issues or to obtain this data. An agency “may not tolerate needless uncertainties in its central assumptions when the evidence fairly allows investigation and solution of those uncertainties.”¹⁴¹

This lack of state and regional granularity contributes to the report’s unreasonable assumptions and overstated conclusions. Rather than focus on a region-specific analysis, DOE engaged in broad approximations to allocate nationwide projections to the various regions. For example, DOE started with a nationwide estimate of 50 GW of incremental data center load, allocated it across regions using state-level growth ratios from S&P’s forecast, then mapped these state-level projections to the regions used for its analysis, the NERC Transmission Planning Regions (TPRs).⁵⁴ It is also unclear how DOE accomplished this mapping, given that the referenced NERC TPRs do not perfectly map to states.⁵⁶

Further, the Report’s conclusions regarding resource adequacy are contradictory at times, even within a single region, rendering DOE’s characterization of certain regions’ resource adequacy arbitrary and capricious. To guide its assessments, DOE set reliability standards of “[n]o more than 2.4 hours of lost load in an individual year” and “[n]o more than an NUSE [Normalized Unserved Energy] of 0.002%.”¹⁴² In its analysis of the PJM region, the Report highlights PJM’s average loss of load figure of 2.4 hours under the current system analysis, apparently to indicate resource inadequacy despite clearly not *exceeding* the threshold DOE set,

¹³⁷ See generally Ex. A, NERC ITCS Report; see also Ex. F, GridStrategies Report at 1.

¹³⁸ See generally Ex. A, NERC ITCS 2024 Report (identifying areas where new transmission can significantly improve reliability); Ex. F, GridStrategies, Resource Adequacy Value of Interregional Transmission (June 2025)

¹³⁹ See Ex. C, IPI Report at 25.

¹⁴⁰ Report at i.

¹⁴¹ *Nat. Res. Def. Council, Inc. v. Herrington*, 768 F.2d 1355, 1391 (D.C. Cir. 1985).

¹⁴² Report at 4.

while also describing the region’s current system as “experienc[ing] shortfalls, but ... below the required threshold.”¹⁴³ At the same time, the Report notes that “[f]or the current system, this analysis identifies an additional 2.4 MW of capacity to meet the NUSE target for PJM,” despite the Report’s summary of the PJM’s modeled NUSE metric in the current system clocking in at 0.0008%, again clearly meeting the reliability threshold that DOE itself selected.¹⁴⁴

The Report also fails to explain how it could be used to identify “at-risk region(s) and guide reliability interventions”¹⁴⁵ while relying on many geographic groupings that do not match the boundaries used by utilities, balancing authority areas, transmission planning regions, regional wholesale markets, NERC regional entities, or NERC reliability coordinators to reliably operate the nation’s electric grid.

For example, the “Front Range” region in the Report includes Colorado and portions of New Mexico and Wyoming but those boundaries are geographically different from regions analyzed in NERC’s reliability assessments. NERC’s 2025 Summer Reliability Assessment includes Colorado, most of Wyoming, and parts of Nebraska and South Dakota in the “WECC-Rocky Mountain” region, and includes Arizona and New Mexico, most of Nevada, and small parts of California and Texas in the “WECC-Southwest” region.¹⁴⁶ The regional grouping used in the Report is arbitrary and inconsistent with these existing groupings.

The Report states its model is derived from NERC’s Interregional Transfer Capability Study (“ITCS”)¹⁴⁷ and asserts the subregions used in the Report, called Transmission Planning Regions (“TPRs”), “match the regional subdivisions in the NERC ITCS study, itself based on FERC’s transmission planning regions.”¹⁴⁸ However, the ITCS makes clear that FERC’s transmission planning regions were altered to create the TPRs for the ITCS,¹⁴⁹ which was focused on transfer capability between neighboring regions and not resource adequacy.¹⁵⁰ The ITCS Final Report does not explain how specific footprints were determined in any detail.¹⁵¹ In January 2025 comments filed with FERC in response to the ITCS report, DOE commented “[t]he subregion boundaries used in the ITCS are useful for evaluating interregional transfer capability given the chosen methodology, *but not for evaluating resource adequacy of those subregions.*”¹⁵² DOE explained the ITCS subregions do not reflect actual monitored transmission constraints, nor

¹⁴³ Report at 27 & Tbl. 8.

¹⁴⁴ Report at 9, 27 Tbl. 8. *See also* Ex. C, IPI Report at 20.

¹⁴⁵ Report at vi.

¹⁴⁶ NERC, *2025 Summer Reliability Assessment* at 36, 38 (May 2025),

https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf.

¹⁴⁷ Report at 2.

¹⁴⁸ Report at 10 n.14.

¹⁴⁹ Ex. A, NERC ITCS Report at 7.

¹⁵⁰ Fiscal Responsibility Act of 2023, H.R. 3746, 118th Congress (2023–2024) (directing NERC to study the total transfer capability between transmission planning regions).

¹⁵¹ *See* Ex. A, NERC ITCS Report at 7.

¹⁵² Comments of the U.S. Dep’t of Energy, FERC Docket No. AD25-4-000, at 6 (Jan. 17, 2025) (emphasis added).

do they accurately capture the service territories or balancing authority areas that are the footprints on which resource adequacy decisions are made.¹⁵³

Despite DOE's earlier comments, the DOE Report fails to explain why the TPR subregions, many of which have no similarities to the regions actually used by NERC to assess reliability nor the planning regions used by entities with resource adequacy obligations, are now appropriate geographic boundaries for running resource adequacy scenarios and guiding reliability interventions. Returning to the example of the Front Range region, neither the ITCS Final Report nor the DOE Report explain why resource adequacy analysis should be done collectively for Colorado and portions of New Mexico and Wyoming, in which the load serving entities and balancing authorities plan their systems, acquire generating resources, and decide to interconnect to neighboring systems under completely separate processes. Because many of the Report's subregions are divorced from how the grid is actually planned and operated, they risk inaccurate groupings of load and available generating resources and incomplete understandings of how transmission capacity may be used in times of peak demand.

The Report suffers from other analytical shortcomings, which are amply described in the Institute for Policy Integrity's report and are expressly incorporated and adopted here.¹⁵⁴ As the Institute for Policy Integrity explained, DOE fails to offer a reasonable explanation for its choice of resource adequacy metrics and targets, outage thresholds, or the use of a deterministic model instead of a more accurate probabilistic model. By relying solely on weather data from recent years in a deterministic model, rather than a more statistically accurate probabilistic model, the Report "does not sufficiently account for uncertainty," weakening the strength of its modeled findings for 2030.¹⁵⁵

Given the abundant shortcomings in DOE's methodology, it is unreasonable to rely on the data and analysis contained in the Report to draw any firm conclusions about the resource adequacy of any region of the United States electrical grid now or in 2030, and DOE's various findings of resource inadequacy despite these flaws is arbitrary and capricious.

iv. DOE's flawed analysis establishes an arbitrary and unlawful preference for fossil fuel plants over other methods to preserve grid reliability, contrary to the Federal Power Act.

The flawed assumptions discussed above lead to an obvious conclusion: that DOE designed the Report to satisfy the White House's goal of bailing out uneconomic and environmentally harmful power plants. DOE's report is not addressing an emergency, but seeking to prop up a coal industry that is unable to compete with cheaper and cleaner modern energy sources like wind, solar, and batteries.

¹⁵³ See *id.* at 6-7.

¹⁵⁴ See Ex. C, IPI Report at 18-26

¹⁵⁵ *Id.* at 21.

Executive Order 14262 was signed alongside EO 14261 *Reinvigorating America's Beautiful Clean Coal Industry and Amending Executive Order 14241*. EO 14261 claims to “encourage and support our Nation’s coal industry to increase our energy supply, lower electricity costs, stabilize our grid, create high-paying jobs, support burgeoning industries, and assist our allies.” And President Trump’s statements at the signing ceremony make clear that the two orders are intended to serve a complementary purpose. As the President said, with coal workers lining the stage behind him for a photo-op, “we’re bringing back an industry that was abandoned” and “all those plants that have been closed are going to be opened.”¹⁵⁶

The President’s Grid Reliability Order references his earlier Declaration of an Energy Emergency, *see* EO 14156 “Declaring a National Energy Emergency,” which created an energy emergency based on an alleged shortage of affordable and domestic energy sources. In all orders, the President narrowly focuses on fossil fuels and specifically excludes wind, solar, or batteries from the definition of “energy.” And the Administration has simultaneously taken steps to derail the wind and solar industries, revoking previously issued permits for offshore wind projects, pausing the issuance of approvals, permits, and loans for wind projects nationwide, and adding bureaucratic hurdles to the permitting process for wind and solar.¹⁵⁷

To the extent that the Report advances the Administration’s policy of discriminating against renewable energy, batteries, and transmission to advance the extra-statutory motive of preserving aging fossil fuel power plants at consumer expense, it is contrary to express goals of the Federal Power Act.¹⁵⁸ Sections 205 and 206 of the Federal Power Act require rates to be just and reasonable and not unduly discriminatory or preferential.¹⁵⁹ Purporting to justify Section 202(c) orders for fossil fuel plants that are not needed and ignoring other viable methods to preserve grid reliability at a lower cost for consumers is likely to result in unjust and unreasonable rates. While 202(c) permits deferral of this issue to FERC in a rate proceeding, DOE must – at minimum – consider how a streamlined and uniform methodology may impact rates and cost recovery.

Significantly, when DOE proposed in 2017 that FERC adjust its rates to compensate generation that could store 90 days of fuel on-site (i.e., coal and nuclear generation), FERC unanimously rejected that proposal.¹⁶⁰ FERC concluded that DOE failed to demonstrate that allowing all eligible resources to receive a special rate regardless of the specific reliability needs of that region would be a just and reasonable outcome.¹⁶¹ DOE also failed to show that such a remedy “would not be unduly discriminatory or preferential” since only “certain resources [could] be eligible for the rate, thereby excluding other resources that may have resilience

¹⁵⁶ Adam Burke, *Trump orders coal revival, but market favors natural gas*, NPR (April 17, 2025)

<https://www.npr.org/2025/04/16/nx-s1-5359013/trump-orders-coal-revival-market-favors-natural-gas>.

¹⁵⁷ *See generally*, Complaint, New York, et al. v. Trump, et al., No. 25-cv-11221 (D. Mass., filed May 5, 2025) (describing Administration’s assault on wind energy). *See also e.g.*, Department of the Interior, Secretarial Order 3437, <https://www.doi.gov/document-library/secretary-order/so-3437-ending-preferential-treatment-unreliable-foreign>; Department of the Interior, Secretarial Order 3438, <https://www.doi.gov/document-library/secretary-order/so-3438-managing-federal-energy-resources-and-protecting>.

¹⁵⁸ *See* FPA Sections 205 and 206; 16 U.S.C. §§ 824d, 824e.

¹⁵⁹ *Id.*

¹⁶⁰ *See* Order Terminating Rulemaking, 162 FERC ¶ 61,012, ¶ 16 (Jan. 8, 2018).

¹⁶¹ *Id.*

attributes.”¹⁶² DOE’s second attempt to manipulate the energy markets in favor of its preferred energy sources suffers from the same fatal flaws and its motives are contrary to the goals of the Federal Power Act.

b. The Report does not describe an “emergency” and cannot be used to justify future grid reliability interventions by DOE.

i. Common usage and regulation define “emergency” narrowly.

Section 202(c) is limited, by its own terms, to either “the continuance of any war in which the United States is engaged,” or “whenever the Commission determines that an emergency exists *by reason of*” certain enumerated causes.¹⁶³ Those causes include: (1) “a *sudden* increase in the demand for electric energy,” (2) “a shortage of electric energy or of facilities for the generation or transmission of electric energy,” (3) a shortage of “fuel or water for generating facilities,” and (4) “other causes.”¹⁶⁴

The relevant focus is therefore on the definition of “emergency.” In 1930, just a few years before the Act’s passage, Webster’s New International Dictionary of the English Language defined “emergency” as a “sudden or unexpected appearance or occurrence... an unforeseen occurrence or combination of circumstances which calls for immediate action or remedy; pressing necessity; exigency.” The year before the statute was last amended, Merriam-Webster’s Dictionary and Thesaurus (2014) defined “emergency” as “an *unforeseen* event or condition requiring prompt action.” Thus, at all relevant times “emergency” was defined as being unexpected or unforeseen and requiring some form of exigent response.

That limited reading of Section 202(c) is bolstered by the emergency provision’s immediate statutory context. Section 202(c) is preceded by Section 202(b), which grants what is now the Federal Energy Regulatory Commission the authority to issue similar interconnection orders “*after* opportunity for hearing,” indicating that Congress intended to place a temporal constraint upon the emergency authority in Section 202(c), limiting it to situations not amenable to public notice and hearing.¹⁶⁵

DOE’s regulations implementing Section 202(c) also suggest the provision’s narrow applicability to only true emergencies.¹⁶⁶ DOE has provided that “actions under this authority are envisioned as meeting a specific inadequate power supply situation.”¹⁶⁷ The regulations

¹⁶² *Id.*

¹⁶³ 16 U.S.C. § 824a(c)(1) (emphasis added).

¹⁶⁴ *Id.* (emphasis added). The catchall “other causes” must still be the “reason” that an emergency exists. *Id.* See also Rolsma, *The New Reliability Override*, 57 U. Conn. L. Rev. at 810-13.

¹⁶⁵ 16 U.S.C. § 824a(b); 42 U.S.C. § 7172(a)(1)(B).

¹⁶⁶ See also 46 Fed. Reg. 39987 (Aug. 6, 1981).

¹⁶⁷ 10 C.F.R. § 205.371.

further define applicable emergencies to include “an *unexpected* inadequate supply of electric energy,” “*unforeseen* occurrences,” or “a *sudden* increase in customer demand,” echoing the.¹⁶⁸

In guidelines for defining “inadequate utility system fuel inventory or energy supply,” the regulations further specify that the threshold for such an emergency may be met “when, combined with other conditions, the projected energy deficiency upon the applicant’s system *without emergency action by the DOE*, will equal or exceed 10 percent of the applicant’s then normal daily net energy for load, or will cause the applicant to be unable to meet its normal peak load requirements *based upon use of all of its otherwise available resources* so that it is unable to supply adequate electric service to its ultimate customers.”¹⁶⁹ This definition again narrows the circumstances in which DOE may exercise its 202(c) authority to those not redressable by other means, implicating only acute or imminent power shortages where no other recourse is available.¹⁷⁰

ii. The report does not point to any sudden or unforeseen circumstances.

. DOE’s report does not identify any region, except ERCOT, that currently fails to meet DOE’s reliability targets.¹⁷¹ DOE’s flawed analysis points to a failure to meet reliability targets only in 2030. An expected increase in demand that can be projected over the next five years is not an energy emergency. Those shortfalls are not “unexpected” or “imminent” so as to justify a departure from normal planning procedures. The Report is squarely focused on 2030 and does not assess resource adequacy in any of the intervening years. According to the standard set out in *Otter Tail Power Co. v. Federal Power Com.*, 429 F.2d 232, 234 (8th Cir. 1970), the shortfalls predicted by the Report are at best policy crises “which [are] likely to develop in the foreseeable future but which [do] not necessitate immediate action.” In other words, the concerns may be addressable using FPA § 202(b), but certainly not FPA § 202(c).

Significantly, DOE has never before issued a 202(c) order based on such a broad and speculative increase in load demand. On the contrary, prior to 2025, DOE had only used 202(c) to delay the retirement of generation facilities on three narrow occasions, as requested by the system operator or government body, and only for as long as necessary to address the imminent emergency.¹⁷²

¹⁶⁸ *Id.* (emphasis added).

¹⁶⁹ 10 C.F.R. § 205.375 (emphasis added).

¹⁷⁰ While the regulations also state that “[e]xtended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities can result in an emergency” the definition crucially does not allow for *projections* of such circumstances to qualify or include any qualifying terms indicating similar intent. On the face of the regulation, and consistent with reasonable interpretations of the statute, such an eligible power shortage must be sufficiently imminent to avoid reducing the inherent limitation of the word “emergency” to an absurdity. 10 C.F.R. § 205.371.

¹⁷¹ Report at 7.

¹⁷² See Benjamin Rolsma, *The New Reliability Override*, 57 U. Conn. L. Rev. 789, 843-46 (2025).

iii. Reliance on the Report to justify a Section 202(c) order would be contrary to law.

Based on EO 14262 and DOE’s own statements, it is evident that the Department intends to rely upon the analysis and methodology in the Report to justify future Section 202(c) orders.¹⁷³ But the Report cannot lawfully be relied upon to justify the exercise of DOE’s limited emergency authority. Doing so would be contrary to law.¹⁷⁴

As discussed above, the Secretary of Energy’s authority under Section 202(c) of the Federal Power Act is statutorily limited to wartime or certain “emergency” situations; otherwise, similar proceedings fall under the jurisdiction of the Federal Energy Regulatory Commission through a process of notice and hearing.¹⁷⁵ Even taking the Report at face value, its own conclusions fail to describe anything resembling an emergency in any part of the country besides ERCOT.¹⁷⁶ Any conclusion that an emergency exists is undermined by the arbitrary nature of the Report’s analysis.¹⁷⁷

Moreover, the Report’s conclusions, on their face, fail to describe an “emergency”. Conclusions about resource adequacy five years in the future, in 2030, fall outside of the temporal limits of an “emergency” and are exactly the type of concern that should be dealt with through usual planning processes.¹⁷⁸ Any attempt by DOE to bootstrap future Section 202(c) orders to the Report would be in direct contradiction to its statutory authority to issue such orders and its own regulations implementing that authority.¹⁷⁹

c. DOE failed to consider an important aspect of the problem: existing reliability mechanisms.

Agency action is arbitrary and capricious under the APA if it “fails to consider an important aspect of the problem.” *Motor Vehicle Mfrs. Assn. of United States, Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983). Here, DOE has acted as if the Report exists on a blank slate of resource adequacy and reliability planning yet that could not be farther from the

¹⁷³ See Report at vi; EO 14262 Sec. 3(c). In at least one Section 202(c) order issued after the publication of EO 14262 but before the release of the Report, the Department stated that it “plans to use this methodology to further evaluate” the generation units subject to that order. Order No. 202-25-4 (“Eddystone 202(c) Order”) at 2 (May 30, 2025).

¹⁷⁴ See 16 U.S.C. § 824a(c); 10 C.F.R. §§ 205.370-371, 375.

¹⁷⁵ 16 U.S.C. §§ 824a(b)-(c); 42 U.S.C. §§ 7151(b), 7172(a)(1)(B).

¹⁷⁶ Report at 7 (“Analysis of the current system shows all regions except ERCOT have less than 2.4 hours of average load loss 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.”); see also Ex. C, IPI Report at 29-31 (“Despite DOE’s press statement asserting that the study’s methodology can help guide [sic] ‘guide Federal reliability interventions,’ presumably to address the EO’s [EO 14262] mandate that DOE find a way to routinize further 202(c) emergency orders, the study reports a fundamental limitation for doing so: It does not find any near-term reliability risk from current levels of resource adequacy.” (footnotes omitted)).

¹⁷⁷ See *supra* Section 4.a.

¹⁷⁸ See Report at 8-9.

¹⁷⁹ 16 U.S.C. § 824a(c); 10 C.F.R. §§ 205.370-371, 375.

truth. As described above, a multilayered system of resource planning involving states and regional grid operators ensures adequate supplies and grid stability.¹⁸⁰

The Report’s conclusion that “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,” is undermined by this failure.¹⁸¹ States across the nation are grappling with how to meet increased demand from AI data centers while maintaining grid reliability and distributing the costs of those changes in an equitable manner. Without an analysis of the existing framework for making such determinations, and ongoing efforts to adjust those systems to meet new challenges, there is no basis for DOE’s conclusion that “intervention” – likely through 202(c) orders – is the only way to possibly reach those goals.¹⁸²

d. As described in the EO, the report intrudes upon state authority.

EO 14262 directs the Secretary of Energy to rely upon the methodology disclosed in the Report to “identify current and anticipated regions with reserve margins below acceptable thresholds” and “identify which generation resources within a region are critical to system reliability.”¹⁸³ The Executive Order also directs DOE to further develop a “protocol” for applying this analysis to “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.”¹⁸⁴ The Report is therefore foundational to the “protocol” that EO 14262 intends will direct emergency orders to override planned retirements. The Report thus directly intrudes on the States’ lawful resource adequacy planning processes.

With respect to regulatory oversight for resource adequacy, section 201 of FPA, 16 U.S.C § 824(b)(1), reserves authority over generation facilities to the states. It states in pertinent part: “The Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, *but shall not have jurisdiction, except as specifically provided in this subchapter and subchapter III of this chapter, over facilities used for the generation of electric energy or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter.*”¹⁸⁵

The Federal Power Act is likewise clear that federal regulatory jurisdiction over the power sector “extend[s] only to those matters which are not subject to regulation by the States.”¹⁸⁶ With the few and specific exceptions outlined elsewhere in the statute, this jurisdiction

¹⁸⁰ See *Supra*, Section 2.a.

¹⁸¹ Report at 1.

¹⁸² *Id.*

¹⁸³ Executive Order 14262, §§ 3(b)-(c).

¹⁸⁴ *Id.* at § 3(c).

¹⁸⁵ *Id.* (emphasis added).

¹⁸⁶ 16 U.S.C. § 824(a).

does *not* extend to “facilities used for the generation of electric energy”¹⁸⁷ This statutory language places the regulation of generation resource adequacy squarely in the ambit of the states, not the federal government.¹⁸⁸

States have typically exercised this authority through a combination of individual state legislative and regulatory functions as well as engaging in multistate RTOs and ISOs. Some states have retained this authority over resource adequacy in its entirety,¹⁸⁹ while others have directed their utilities to join RTOs/ISOs that, through their tariffs, impose resource adequacy requirements. Those RTO/ISOs also generally establish markets that allow market participants to buy and sell capacity and thereby to facilitate market entry and exit decisions based on price signals. Resource adequacy requirements in RTO/ISO tariffs have been held to be practices affecting wholesale rates subject to the jurisdiction of FERC under sections 205 and 206 of the Federal Power Act, 16 U.S.C. §§ 824d & 824e.¹⁹⁰

Through these channels, states conduct the careful, calculated, long-term capacity planning that goes ignored in DOE’s Report.¹⁹¹ The Report utterly fails to recognize or properly account for the states’ traditional and statutory role in resource adequacy planning, and as forecasted by EO 14262, the Report constitutes a central component of the federal government’s proposed protocol to usurp the states’ authority over this issue.

The use of emergency orders to illegally override state resource adequacy planning has been challenged on the same grounds by the Organization of MISO States, Inc. (OMS), in its Petition for Rehearing of DOE Order No. 202-25-3 (ordering continued operation of the J.H. Campbell coal-fired power plant). In its Petition, OMS noted among other points that “[t]his is the first time the DOE has invoked Section 202(c) outside a severe weather event or emergency, and for the first time, uses the power to suspend a retirement and interfere with established and vetted state and regional planning processes.”¹⁹² OMS’ petition continues, “[t]his expansive use of emergency powers sets a troubling precedent, enabling interventions in routine, state-approved planning decisions without an actual crisis and risks establishing its use to circumvent normal utility, RTO, and states processes, and likely exposes ratepayers to costs that should not be borne.”¹⁹³ In DOE’s issuance of the Report pursuant to EO 14262, the federal government is

¹⁸⁷ *Id.* § 824(b)(1).

¹⁸⁸ *See, e.g.,* Ashley J. Lawson, CONG. RESEARCH SERV., R47521, *Electricity: Overview and Issues for Congress*, at 7 (Feb. 14, 2025).

¹⁸⁹ *See Devon Power LLC et al.*, 109 FERC ¶ 61,154, P 47 (2004) (“Resource adequacy is a matter that has traditionally rested with the states, and it should continue to rest there. States have traditionally designated the entities that are responsible for procuring adequate capacity to serve loads within their respective jurisdictions.”).

¹⁹⁰ *See Conn. Dep’t of Pub. Util. Control v. FERC*, 569 F.3d 477, 483 (D.C. Cir. 2009).

¹⁹¹ *E.g.,* Report at 2-3, 5, 12-13 (relying solely on federal, EIA, and NERC estimates and failing to mention nuanced state, RTO, or ISO figures and actions).

¹⁹² *See* Petition to Intervene and Request for Rehearing of the Organization of MISO States, Inc., Order No. 202-25-3 (filed June 23, 2025), <https://www.energy.gov/sites/default/files/2025-07/Petition%20to%20Intervene%20and%20Request%20for%20Rehearing%20of%20the%20Organization%20of%20MISO%20States.pdf>.

¹⁹³ *See id.* at 5; *see also id.* at 4 (challenging “Violation of the Federal Power Act and State Jurisdiction.”).

attempting to establish its own rule for resource adequacy planning from which it can routinely issue illegal orders under the same flawed premise that OMS challenges in its Petition.

Lastly, Section 202(c) does not serve as a widespread grant of DOE jurisdiction over resource adequacy and capacity planning. “Congress ... does not ... hide elephants in mouseholes.”¹⁹⁴ First, as described above in Part [3b], Congress assigned non-emergent questions of interconnection and transmission necessity amenable to public notice and hearing to FERC, not DOE.¹⁹⁵ Moreover, even this authority should not be seen as a substitute for the overarching reservation of regulatory jurisdiction over resource adequacy planning to the states.¹⁹⁶ No reasonable reading of the relevant statutory authorities could construe DOE’s authority in 16 U.S.C. § 824a(c) as intruding on the explicit and traditional role of the states in regulating electricity generation and resource adequacy. However, all available indicators in the Report and EO 14262 evince a flawed understanding contrary to DOE’s appropriate and limited role in this space, thus the Department should reconsider its findings and position on this authority.

e. DOE’s Failure to Provide Public Notice and Comment on its New Standard and Methodology Violated the Administrative Procedure Act, 5 U.S.C. § 553.

Before adopting a final rule, the Administrative Procedure Act requires agencies to publish in the Federal Register a notice of proposed rulemaking and accept public comment.¹⁹⁷ An agency action that imposes legally binding obligations or prohibitions on regulated parties, substantially removes the agency’s discretion, or would be the basis for an enforcement action for violations of those requirements, is a legislative rule that requires notice and comment.¹⁹⁸ Notice and comment is also required when agencies establish new standards that are not derived from an existing statute or regulation or when an agency relies on its statutorily delegated authority to establish policy.¹⁹⁹ Additionally, agency documents that adopt a “new position inconsistent with any of the [agency’s] existing regulations” are subject to notice and comment.²⁰⁰

DOE’s report creates a brand-new national standard and methodology for evaluating resource adequacy. This standard has concrete legal effects because DOE plans to enforce it via Section 202(c) emergency orders. It also is inconsistent with DOE’s existing regulations, which direct DOE to issue emergency orders in very different circumstances based on different criteria than what DOE now proposes. Significantly, DOE acknowledges that its conclusions lack sufficient input from the entities responsible for operating the grid, but DOE nonetheless refused to submit the Report to notice and comment where the public could have tested DOE’s assumptions and conclusions. Assuming DOE continues to comply with the Executive Order’s

¹⁹⁴ *Whitman v. Am. Trucking Ass’ns, Inc.*, 531 U.S. 457, 468 (2001).

¹⁹⁵ 16 U.S.C. § 824a(b); 42 U.S.C. § 7172(a)(1)(B).

¹⁹⁶ 16 U.S.C. §§ 824(a)-(b).

¹⁹⁷ 5 U.S.C. § 553(b)-(c).

¹⁹⁸ *See Nat’l Min. Ass’n v. McCarthy*, 758 F.3d 243, 251–52 (D.C. Cir. 2014).

¹⁹⁹ *See Children’s Hosp. of the King’s Daughters, Inc. v. Azar*, 896 F.3d 615, 622 (4th Cir. 2018).

²⁰⁰ *Shalala v. Guernsey Mem’l Hosp.*, 514 U.S. 87, 99–100 (1995).

unlawful command to use this Report to support future Section 202(c) orders, the Report and any action relying on it must be set aside for failure to provide notice and comment.

i. DOE’s standard is an exercise of assumed legislative authority, and it has concrete legal effects.

Pursuant to the Executive Order, DOE established a “uniform methodology” for assessing resource adequacy across the country.²⁰¹ That methodology adopts a new “resource adequacy standard” to measure the desired level of adequacy needed for the bulk power system.²⁰² DOE acknowledges that it is not using the “traditional . . . criterion” for measuring resource adequacy and is relying on metrics that are “not standardized in the U.S. today.”²⁰³ Instead, DOE unilaterally adopts new metrics to evaluate resource adequacy and establishes the reliability targets that should be obtained.²⁰⁴ DOE’s choice of metrics and the targets to be achieved are value judgments and should be informed by economic tradeoffs and other policy considerations about what level of system reliability should be achieved and at what cost to consumers, areas where public input is essential to sound decision making.²⁰⁵

DOE also fills its methodology with value-laden policy choices around the data inputs and assumptions that determine when DOE’s reliability standard is achieved. As just one example, DOE includes projected future demand from potential new AI data centers as part of its calculation of future load.²⁰⁶ Those data centers have not yet been built and some may never be.²⁰⁷ And, as DOE recognized, grid operators are not likely to allow those large loads to connect if doing so threatens reliability.²⁰⁸ Including those potential loads in DOE’s determinations of system reliability thus inherently represents a policy choice: Should present-day consumers pay to keep retiring power plants online to ensure that potential data centers can be reliably served in the future?²⁰⁹

Even assuming *arguendo* that DOE has the statutory authority to set a uniform reliability standard, place risks of future large load growth on current consumers, or engage in long-term resource adequacy planning for the entire nation, it still must involve stakeholders through notice and comment in those legislative choices. “When an agency relies on expressly delegated authority to establish policy . . . courts generally treat the agency action as legislative [] rulemaking” and require notice and comment.²¹⁰ In other words, “when Congress leaves [] a policy choice to the agency, [courts] should lean toward finding that the agency’s making of that

²⁰¹ See Report at vi (explaining that the report is “delivering the required uniform methodology to identify at-risk region(s)”; Executive Order 14262 § 3(b).

²⁰² Report at 3.

²⁰³ *Id.* 3-4.

²⁰⁴ See *id.*

²⁰⁵ See Ex. C, IPI Report at ii (criticizing DOE’s choice of targets as not “appropriately justified based on a cost-benefit framework, and the use of a one-size-fits-all target for the entire country ignores regional differences”).

²⁰⁶ See Report at 1-3.

²⁰⁷ See, e.g., Ex. E, London Economics International Report; Laila Kearney and Liz Hampton, *U.S. Power Stocks Plummet as DeepSeek Raises Data Center Demand Doubts*, Reuters (Jan. 27, 2025) <https://www.reuters.com/business/energy/us-power-stocks-plummet-deepseek-raises-data-center-demand-doubts-2025-01-27/>.

²⁰⁸ See Report at 14.

²⁰⁹ See also *supra* Section 4.a. (discussing other arbitrary assumptions in DOE’s analysis).

²¹⁰ *Children’s Hosp. of the King’s Daughters, Inc.*, 896 F.3d at 622.

choice requires notice and comment.²¹¹ “Otherwise, it would be difficult to imagine what regulations *would* require notice and comment procedures.”²¹²

DOE’s standard also has concrete legal effects because, consistent with the Executive Order, DOE will use Section 202(c) emergency orders (or the threat of Section 202(c) orders) to ensure regions meet the new standard. The Executive Order directs DOE to use this standard to “establish . . . a protocol” to identify generation resources that are critical to system reliability.²¹³ DOE’s “protocol shall additionally” use Section 202(c) of the Federal Power Act to “ensure” those resources are retained and prevent their retirement.²¹⁴ “Protocol” means “a set of rules to be followed . . .”²¹⁵ As DOE has made clear, DOE “plans to use” this new standard to evaluate retiring coal plants and potentially issue Section 202(c) emergency orders preventing their retirement.²¹⁶

DOE’s new standard, and protocol for enforcing it, removes DOE’s discretion and is intended to provide the basis for enforcement actions via Section 202(c) orders.²¹⁷ The new standard is not derived from the Federal Power Act or, as explained further below, from DOE’s existing regulations, but is an entirely new method of determining resource adequacy across the country. DOE must accordingly submit its new standard and methodology to public notice and comment.²¹⁸

ii. DOE must provide notice and comment because its standard allegedly supports issuing emergency orders based on factors that conflict with existing regulations.

DOE’s Report provides new bases for issuing emergency orders that conflict with DOE’s existing regulations, but DOE cannot amend those standards without first providing notice and comment.²¹⁹ DOE promulgated regulations detailing how and when it issues Section 202(c) emergency orders following public notice and comment in 1981.²²⁰ Under DOE’s current regulations, emergency orders “are envisioned as meeting a *specific* inadequate power supply situation,” occasioned by “acts of God[] or unforeseen occurrences not reasonably within the

²¹¹ *Id.*

²¹² *Id.* (quoting *N.H. Hosp. Ass’n v. Azar*, 887 F.3d 62, 70–71 (1st Cir. 2018)).

²¹³ Executive Order 14262 at § 3(c).

²¹⁴ *Id.*

²¹⁵ PROTOCOL, Black’s Law Dictionary (12th ed. 2024).

²¹⁶ Order No. 202-25-4 at 2 (Eddystone Order). *See also* U.S. DEPT OF ENERGY, *Fact Sheet: The Department of Energy’s Resource Adequacy Report Affirms The Energy Emergency Facing The U.S. Power Grid* (2025), https://www.energy.gov/sites/default/files/2025-07/DOE_Fact_Sheet_Grid_Report_July_2025.pdf [<https://perma.cc/YLX7-8G7T>] (explaining that DOE’s methodology will be used, pursuant to the executive order, “prevent [] generation resources from leaving the bulk-power system”); Press Release, U.S. Dep’t of Energy, Department of Energy Releases Report on Evaluating U.S. Grid Reliability and Security (July 7, 2025), <https://www.energy.gov/articles/department-energy-releases-report-evaluating-us-grid-reliability-and-security> [<https://perma.cc/8TEJ-AGH6>]. (stating that its “methodology also informs the potential use of DOE’s emergency authority under Section 202(c) of the Federal Power Act”); Report at *vi* (explaining that DOE’s standard will be used to “guide reliability interventions”), 1 (emphasizing the need for DOE’s “decisive intervention” in energy markets), 10 (analyzing ERCOT because “FPA Section 202(c) allows DOE to issue emergency orders to ERCOT”).

²¹⁷ *See Nat’l Min. Ass’n v. McCarthy*, 758 F.3d 243, 251–52 (D.C. Cir. 2014).

²¹⁸ *See id.*; *Children’s Hosp. of the King’s Daughters, Inc. v. Azar*, 896 F.3d 615, 622 (4th Cir. 2018).

²¹⁹ *See Shalala*, 514 U.S. at 99–100.

²²⁰ *See Emergency Interconnection of Electric Facilities*, 46 Fed. Reg. 39,984 - 39,989 (Aug. 6, 1981).

power of the affected ‘entity’ to prevent.”²²¹ DOE did not intend its emergency authority to replace long-term planning by utilities: “while a utility may rely upon these regulations for assistance during a period of unexpected inadequate supply of electricity, it must solve long-term problems itself.”²²²

As DOE stated then, “[t]he factors that DOE will consider in determining whether an emergency exists are specified in § 205.373.”²²³ Section 205.373 requires applicants to submit detailed information on “daily peak load and energy requirements for each of the past 30 days and projections for each day of the expected duration of the emergency” and make a “showing that adequate electric service cannot be maintained without additional power transfers.” Applicants must also describe what “conservation or load reduction actions have been implemented” before seeking emergency relief.²²⁴ In sum, DOE’s current regulations direct a case-by-case analysis of specific, temporary shortages in particular situations, based on detailed information from an applicant.

DOE’s new standard and methodology is an unprecedented expansion of the bases upon which DOE will justify Section 202(c) emergency orders, but DOE has not offered public comment on that expansion. Rather than focusing on specific showings of an imminent threat to grid stability, the report rests on DOE’s analysis of “the U.S. electric grid’s ability to meet future demand through 2030.”²²⁵ Rather than consider the “daily peak load and energy requirements of the past 30 days and projections for each day of the [] emergency,” 10 C.F.R. § 205.373, DOE now plans to base Section 202(c) decisions on speculation over the development of artificial intelligence, re-industrialization of the U.S. economy, and other uncertain developments over the next five years.²²⁶ Rather than consider the “scheduled . . . deliveries” during the emergency period and needs of existing firm customers, § 205.373(d),(f), DOE now proposes to find an emergency based on potential load growth for customers who do not currently, and may never, exist.²²⁷

Rather than allowing utilities and grid operators to solve long-term planning issues themselves, DOE now seeks to intervene in those state- and FERC-regulated processes based on its own assumptions about future load growth and electricity supply. But unlike DOE’s Report, the long-term resource adequacy plans developed by utilities and grid operators are transparent and publicly-accountable processes that involve relevant stakeholders and the public.²²⁸ DOE, on the other hand, published its analysis without critical data or insights from the entities who actually operate and maintain the electric grid.²²⁹

²²¹ 10 C.F.R. § 205.371 (emphasis added).

²²² 46 Fed. Reg. at 39,985; *see also* 10 C.F.R. § 205.371

²²³ 46 Fed. Reg. at 39,985.

²²⁴ *Id.*; *see also* 10 C.F.R. § 205.375 (defining an inadequate energy supply as when an applicant is “unable to meet its normal peak load requirements based upon use of all its otherwise available resources.”).

²²⁵ Report at 2.

²²⁶ Report at 2; *see also supra* Section 4.a.

²²⁷ *See, e.g.,* Ex. E London Economics International Report; Laila Kearney and Liz Hampton, *U.S. Power Stocks Plummet as DeepSeek Raises Data Center Demand Doubts*, Reuters (Jan. 27, 2025)

<https://www.reuters.com/business/energy/us-power-stocks-plummet-deepseek-raises-data-center-demand-doubts-2025-01-27/>.

²²⁸ *See supra* Section 2.a.

²²⁹ Report at *i*.

Rather than considering what other “conservation or load reduction actions have been implemented” before turning to emergency relief, 10 C.F.R. § 205.373, DOE’s standard ignores those possibilities altogether. Instead, DOE adopts aggressive and likely overstated assumptions of load growth and ignores whether any of that future demand could be flexibly integrated into the grid, what measures state and local regulators are taking to mitigate the impact of new data center demand on grid reliability, or other factors influencing grid reliability over the long-term.²³⁰ DOE appears to admit that its overstated potential load growth will not *actually* lead to any grid reliability emergency, as there is no “indication that reliability coordinators would allow this level of load growth to jeopardize the reliability of the system.”²³¹

DOE appropriately involved the public when it initially set out the process and factors to consider for Section 202(c) orders in its 1981 rulemaking. Yet now, DOE seeks to expand the bases for Section 202(c) orders in ways that intrude on state-regulated processes and the free market, without any input from stakeholders or the public who will ultimately pay for DOE’s actions. Because the methodology and protocol effectively “expand[s] the footprint [of DOE’s emergency authority] by imposing new requirements, rather than simply interpreting the legal norms Congress or the agency itself has previously created” and is inconsistent with DOE’s existing regulations, it is a “rule” under the APA and notice and comment is required.²³²

iii. DOE acknowledges the importance of involving the States and other actors yet fails to provide public notice and comment to test DOE’s assumptions and conclusions.

DOE’s failure to provide public notice and comment is prejudicial error. DOE admittedly lacks the “range of data and insights” to make robust reliability decisions that entities responsible for the maintenance and operation of the grid have access to.²³³ Had the States been given adequate notice and an opportunity to comment, they could have provided more information to DOE on how existing mechanisms address grid reliability, issues with DOE’s assumptions, chosen metrics, and choice of data, identified gaps in DOE’s analysis and data, and other issues. Numerous grid experts have commented on shortfalls with DOE’s report.²³⁴ Given adequate notice and an opportunity to comment, the States could have obtained their own expert analysis and potentially raised even more issues with DOE’s proposed standard and methodology than what time permitted the States to raise here.

DOE has previously acknowledged the importance of involving States and the public in these questions. When DOE initially established regulations governing how and when it would

²³⁰ See, e.g., Ex. D, Nicholas Institute Report; Jason Plautz, *State lawmakers grapple with energy demand for data centers*, E&E News (Mar. 3, 2025) <https://www.eenews.net/articles/state-lawmakers-grapple-with-energy-demand-for-data-centers/>; Washington Office of the Governor, *Gov. Bob Ferguson Signs Executive Order Establishing a Data Center Workgroup* (Feb. 4, 2025) <https://governor.wa.gov/news/2025/governor-bob-ferguson-signs-executive-order-establishing-data-center-workgroup>.

²³¹ Report at 14.

²³² *Children’s Health Care v. Centers for Medicare & Medicaid Servs.*, 900 F.3d 1022, 1025 (8th Cir. 2018); see also *Shalala*, 514 U.S. at 99–100.

²³³ Report at *i*

²³⁴ See, e.g., Jeff St. John, *Critics fear Trump will use flawed DOE report to push pro-coal agenda*, Canary Media (July 14, 2025), <https://www.canarymedia.com/articles/fossil-fuels/trump-doe-report-open-coal-plants>; Matthias Fripp and Brendan Pierpont, Opinion, *Energy Department’s flawed grid study props up expensive, zombie power plants*, UtilityDive, <https://www.utilitydive.com/news/doe-grid-reliability-study-zombie-power-plants/753596/>.

issue emergency orders, DOE consulted with the Federal Energy Regulatory Commission and state officials.²³⁵ DOE also explained that “[t]he DOE intends to utilize any available State and local expertise in resolving an emergency.”²³⁶ Indeed, DOE’s organizational statute *requires* it to consult with States “[w]henver any proposed action by the Department conflicts with the energy plan of any State.”²³⁷ And States are already taking actions to address reliability issues and load growth in their jurisdictions.²³⁸ DOE’s refusal to collaborate with States or meaningfully involve other stakeholders here is inexplicable, conflicts with DOE’s organizational statute, and the APA.

V. Conclusion

The State’s request for rehearing should be granted and DOE should withdraw or otherwise amend the subject Report following public vetting through notice and comment proceedings. In the meantime, DOE cannot rely on the challenged report to support the exercise of its 202(c) authority. Doing so would be arbitrary and capricious and otherwise contrary to law and impose significant harm on our States.

Filed: August 6, 2025

²³⁵ 46 Fed. Reg. at 39,985.

²³⁶ *Id.*

²³⁷ 42 U.S.C. § 7113; *see also* 16 U.S. Code § 824h (encouraging federal-state collaboration).

²³⁸ Jason Plautz, *State lawmakers grapple with energy demand for data centers*, E&E News (Mar. 3, 2025) <https://www.eenews.net/articles/state-lawmakers-grapple-with-energy-demand-for-data-centers/>; Washington Office of the Governor, *Gov. Bob Ferguson Signs Executive Order Establishing a Data Center Workgroup* (Feb. 4, 2025) <https://governor.wa.gov/news/2025/governor-bob-ferguson-signs-executive-order-establishing-data-center-workgroup>.

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Attachment T

Francone Letter 9.5.25



Department of Energy

Washington, DC 20585

September 5, 2025

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RE: August 6, 2025 Submission

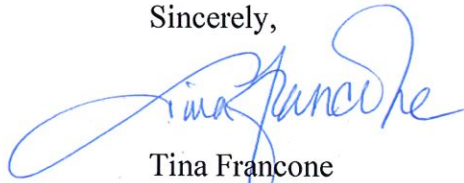
To Whom It May Concern:

Thank you for your August 6, 2025 submission on behalf of the Attorneys General of Maryland, Washington, Illinois, Michigan, Minnesota, Arizona, Colorado, Connecticut, and New York (collectively, the State AGs). The submission was titled “Motion to Intervene and Protective Request for Rehearing by the Attorneys General of Maryland, Washington, Illinois, Michigan, Minnesota, Arizona, Colorado, Connecticut, and New York” (Submission). It was not filed in any active docket.

On July 7, 2025, the U.S. Department of Energy (DOE) issued the Report on Strengthening U.S. Grid Reliability and Security (Resource Adequacy Report or RAR), fulfilling Section 3(b) of Executive Order 14262. The RAR presents a unified, transparent methodology for assessing the reliability of the bulk power system and identifying regions at elevated risk of resource inadequacy under projected load growth and plant retirement scenarios. DOE developed this approach in coordination with NERC and leading industry experts to provide a consistent, data-driven framework for informing federal reliability interventions, particularly as the grid faces surging demand from AI-driven data centers, reindustrialization, and electrification.

In the Submission, the State AGs seek rehearing of the RAR under section 313 of the Federal Power Act (FPA).¹ An application for rehearing under section 313 of the FPA² may be filed only by a “person, electric utility, State, municipality, or State commission” that is “aggrieved” by “an order issued by [DOE].”³ If these prerequisites are not met, there is no basis for rehearing. Here, we note that the RAR is simply a report that details the current condition of the United States electrical grid. It contains no directives, nor does it impose legal duties upon any party, including the State AGs. As such, it cannot be considered an “order” by which the State AGs are “aggrieved” within the meaning of section 313 of the FPA, as would be required to request rehearing. Accordingly, DOE will take no action on the Submission.

Sincerely,



Tina Francone
Director of the Grid Deployment Office, Acting

¹ Submission at 1.

² 16 U.S.C. § 8251(a).

³ *Id.*

Attachment U

MISO, 2023 Attributes Roadmap631174

Attributes Roadmap

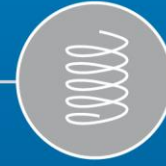
A RELIABILITY IMPERATIVE REPORT



SYSTEM
ADEQUACY



FLEXIBILITY



SYSTEM
STABILITY

DECEMBER 2023

Highlights

- The evolving energy landscape requires MISO and the industry to understand the increasing complexity of the transitioning system and proactively adapt to increasing risk and changing system conditions
- MISO's 2023 analysis highlights the need for market reforms and new requirements to ensure the sufficiency of three priority attributes where near-term risk is most acute: system adequacy, flexibility, and system stability
- The *Attribute Roadmap* recommends advancing a combination of current and new proposals as well as providing ongoing attributes visibility through regular reporting



misoenergy.org



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Version Number	Purpose / Change	Date
1.0	Initial posting.	December 2023
1.1	Updated with hyperlinks between the <i>Technical Appendix</i> and the <i>Attributes Roadmap</i> and correction of minor typos per stakeholder feedback.	June 2024



Executive Summary

INTRODUCTION

The *Attributes Roadmap* presents insights and solutions following an in-depth look at the challenges of operating a reliable bulk electric system in a rapidly transforming energy landscape. The generation resource mix is diversifying; the surety of the fuel supply is declining; extreme weather is increasing in intensity and duration; and industrial load growth and electrification trends are poised to disrupt traditional load patterns. These factors create complex challenges for MISO and stakeholders and a shared imperative to urgently act to avoid a looming shortage of necessary system reliability attributes and ensure electricity is delivered every hour of every day to the 45 million people in the MISO region.

No single resource provides every needed system attribute. The needs of the system have always been met by a fleet of diverse resources operated in a manner that most efficiently meets the system needs. Preparing for the energy transition requires an improved understanding of the reliability attributes of the bulk electric system and the advancement of urgent market reforms and requirements to meet the changing system needs.

In 2023, MISO designed and completed a foundational analysis of the system reliability attributes. The analysis focused on three priority attributes where risk to the MISO system is most acute: **system adequacy, flexibility, system stability**, and their near-term risk factors (Figure 1). MISO developed recommended approaches and solutions based on input from various expert sources, including MISO's internal subject matter experts and past analyses, MISO stakeholders, external industry research, and leading industry experts.

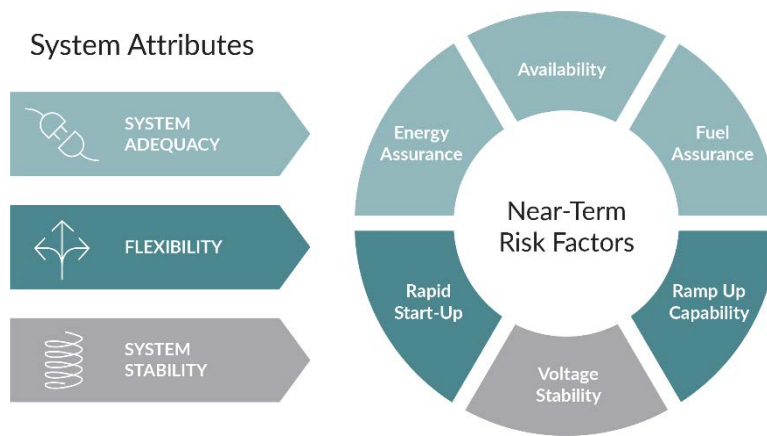


Figure 1: Three priority system reliability attributes and their near-term risk factor focus areas

INSIGHTS AND SOLUTIONS

To meet the rapidly evolving needs of the bulk electric system, urgent action is needed to advance a targeted portfolio of market reforms and system requirements, and to provide ongoing attributes visibility through regular reporting. In summary:

SYSTEM ADEQUACY refers to 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.

- Approach: Best addressed in the planning horizon and served through capacity requirements, capacity accreditation (valuation), and market solutions within the seasonal resource adequacy construct where a diverse range of generation resources can contribute to meeting demand and



reserve requirements. Additionally, evolved coordination is needed between MISO's resource adequacy assessments and MISO state and member planning processes.

- Recommendations: MISO recommends a continued focus on one market clearing product (capacity), and further modernizing the resource adequacy construct to address emerging attribute-related risk factors through improved risk modeling, capacity accreditation, and capacity market qualification requirements. Additionally, MISO recommends providing visibility into future regional system adequacy needs and capabilities through improved forecasting and reporting.

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.

- Approach: Best addressed in the operating timeframe and served through market solutions where resources can compete to meet the increasingly variable and uncertain real-time operational needs of the system.
- Recommendation: MISO recommends advancing two strategic objectives to address this attribute: (1) focus market signals on emerging flexibility needs through expanded and new ancillary service products, and (2) expand the fleet of qualifying resources able to provide flexibility by enhancing market systems and reforming resource participation models to enable emerging technologies to fully participate.

SYSTEM STABILITY is the ability to remain in a state of operating equilibrium under normal operating conditions and to also recover from disturbances. MISO focused on the nearest-term risk factor of voltage stability.

- Approach: Best addressed initially through requirements and technology standards and a multistep approach to require capabilities from resources to support grid stability.
- Recommendation: MISO recommends requirements for inverter-based resource controls as part of the resource interconnection process and incentives for critical reliability capabilities as needed.

The *Attributes Roadmap* includes current and new proposals to ensure the sufficiency of the priority system reliability attributes with approximate project relationship and timing (Figure 2). The report discusses each of these recommendations in detail as well as the analysis and research that supports the recommendations.

NEXT STEPS

The attributes insights and solutions will further inform the region's Reliability Imperative priorities. MISO's next step will be to integrate the recommendations into its processes with stakeholder engagement throughout. In addition, MISO will continue to monitor the efficacy of planned and implemented solutions, study additional system attributes, and consider solutions beyond this recommendation.

Timely collaboration is needed between MISO, its stakeholders, and the broader industry to continue this mission-critical work and ensure the region is prepared to reliably navigate the energy transition.

Find the latest project status on MISO's Dashboard for "[Identification of Sufficient Reliability Attributes RASC – 2022-1](#)." Ongoing system attributes work will be coordinated through the MISO Stakeholder [Resource Adequacy Subcommittee](#).

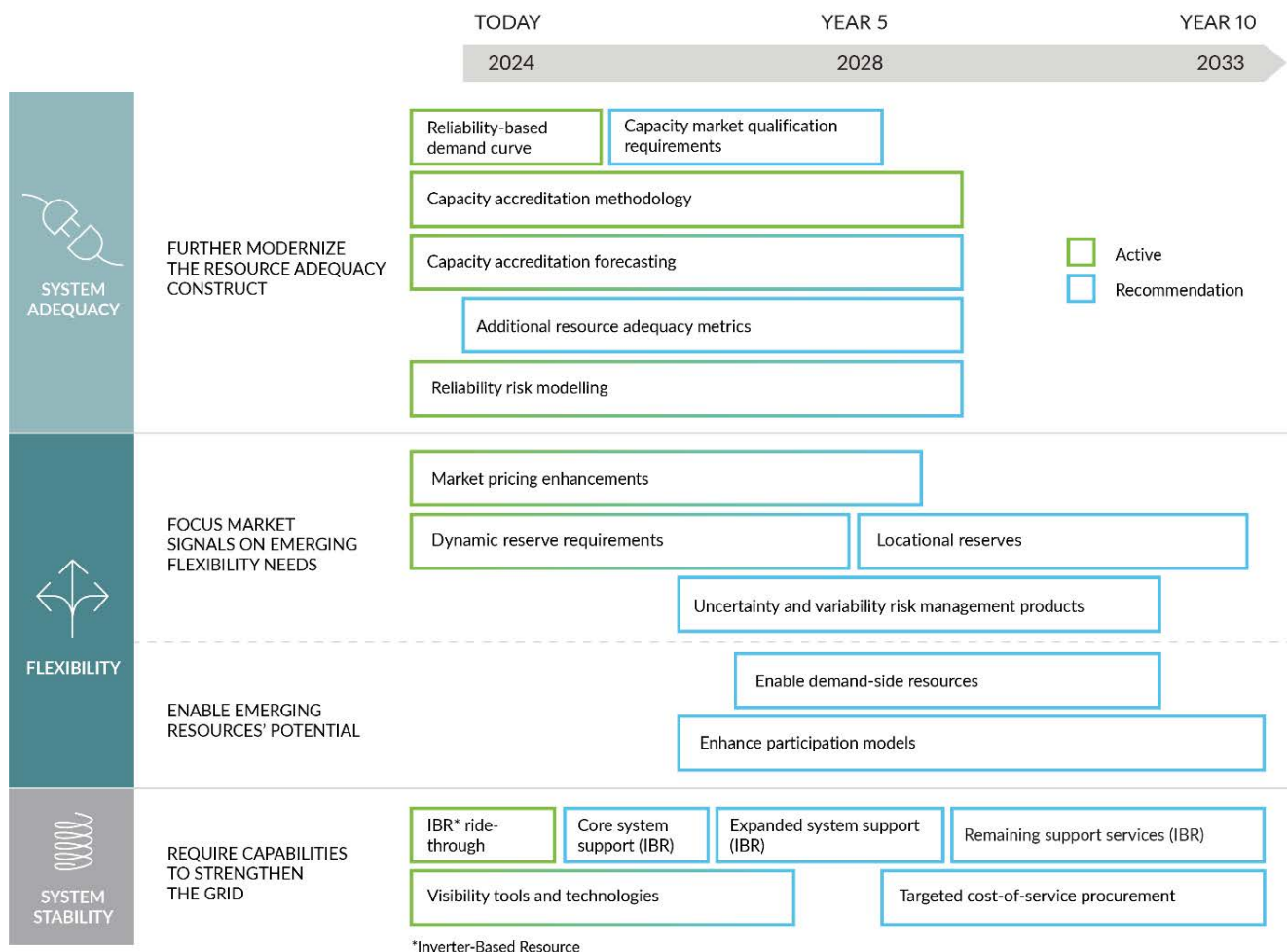


Figure 2: Hypothesis for attributes solution roadmap with approximate timing for projects currently underway (active) and proposed future projects (recommendation). The *Attributes Roadmap* discusses each recommendation in detail as well as the analysis and supporting research.



Project Introduction and Approach

System reliability attributes are characteristics of the bulk electric system. A wide range of attributes is needed to ensure reliability and support the region’s affordability and sustainability objectives. Importantly, no single generating resource provides every needed system attribute.¹ The foundational needs of the system have always been met by a fleet of diverse resources operated in a manner that most efficiently meets system needs.

As the system transforms, strategic assessments by MISO and other industry experts conclude that system reliability attributes will need to be increasingly studied, measured, incentivized, and required for the bulk electric system to maintain its expected levels of reliability.

MAJOR DRIVERS OF CHANGE INTRODUCE NEW AND SHIFTING SYSTEM RISK

Major industry trends are simultaneously changing the conditions of the system, for example:

- New generation and load resources coming online often do not have the same characteristics as the resources they are replacing, introducing the potential risk that the needs of the system will not be met by the transitioning fleet.
- Increased impacts from severe weather creates major challenges in managing transmission congestion, high rates of correlated forced outages, and extended periods of high demand.
- Demand for electricity is increasing to meet new needs (e.g., the information economy, efforts to rebuild domestic supply changes, and electrification) and disrupting traditional load patterns.

See [MISO’s Response to the Reliability Imperative](#) for a more detailed analysis of trends and drivers of change in the MISO region.

PAST STUDIES INFORM PRIORITIZATION AND APPROACH

The attributes project was informed by previous MISO studies assessing the region’s changing risk profile and exploring the reliability impact of the major drivers. This work includes:

[Markets of the Future:](#) Illustrated how and when MISO’s existing market structures will need to evolve to accommodate the profound changes that are occurring in the energy sector. The needs were 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 attributes work.



[MISO Futures:](#) Utilized 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 attributes team used the recently refreshed Future 2A forecasted resource portfolios to perform the forward looking five-year and 10-year analysis.



¹ EPRI, [Energy Supply Reference Card](#), 2023 Version.



Renewable Integration Impact Assessment (RIIA): Assessed the impacts of integrating increasingly higher levels of renewables into the MISO system. This assessment steered the attributes project in many ways, including the key finding that voltage stability and inverter-based converter stability are among the first system stability related challenges the MISO system will likely face.



Regional Resource Assessment (RRA): Recurring study based on the plans and goals that MISO members have publicly announced for their generation resources. This year's attributes analysis built upon the flexibility assessments of net load variability and uncertainty changes originally presented within the RRA.



The February (2021) Arctic Event: Discussed 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. The attributes work used Uri as a case study.



EXPLORATION OF THE SOLUTIONS LANDSCAPE

MISO began the process of developing possible solutions to the major questions regarding system adequacy, flexibility, and system stability by soliciting input from expert sources (Figure 3). From these queries, MISO filtered more than 100 possible solutions to the problems proposed.

Many solution options came from MISO's internal experts and past reports. Stakeholder discussions offered ideas, including recommendations for MISO's Independent Market Monitor (IMM). The team reviewed relevant industry research and literature, including work led by the Energy System Integration Group, NERC's Energy Reliability Assessment Task Force, and the Electric Power Research Institute (EPRI). Additionally, MISO reviewed the actions and published analysis of other grid operators, including PJM and ERCOT, the Australian Energy Market Operator, and UK's National Grid Electricity System Operator.

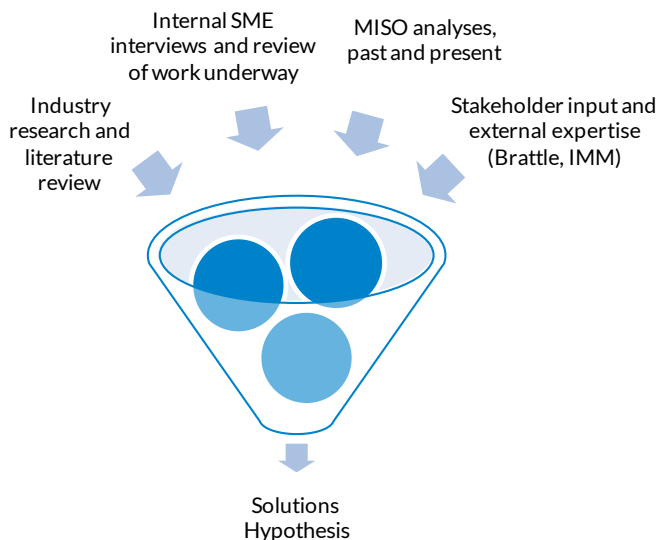


Figure 3: Sources of solutions considered

Solutions exploration and focus was done in consultation with The Brattle Group. MISO engaged Brattle on strategy and risk approaches, evaluation of the solutions for impact and efficiency, and industry expertise on solution implementation outcomes in other regions. Brattle presented its recommendation to the Resource Adequacy Subcommittee (RASC) in October 2023.²

² Brattle, "[MISO Reliability Attributes Solution Space](#)," presented to MISO's Resource Adequacy Subcommittee (RASC), October 4, 2023.



CRITERIA FOR EVALUATING CANDIDATE SOLUTIONS

Solutions were narrowed based on the following evaluation criteria:

TECHNICAL CRITERIA

- ✓ Helps **attract/retain** sufficient resources to provide the target reliability attribute
- ✓ **Operationally utilizes** the resource to provide the attribute

ECONOMIC CRITERIA

- ✓ Promotes **economically efficient investment**
- ✓ Promotes **economic efficient operations and performance**

PROCESS CRITERIA

- ✓ Provides **transparency** and predictability, without excessive complexity
- ✓ Has acceptable **implementation cost and time**

OTHER CONSIDERATIONS

- ✓ **Resource neutrality**
- ✓ Informs **long-term planning** for states and members
- ✓ **Adaptability** to change in policies and market conditions
- ✓ **Compatibility** with existing processes, markets, and policies

MISO applied the quantitative criteria against the initial list of solutions. With the shorter list of solution candidates, quantitative analysis was completed wherever practical to test the working hypotheses.

FOUNDATIONAL ANALYSIS AND SOLUTIONS

This report is divided into three sections, one for each priority attribute: system adequacy, flexibility, and system stability. Each section begins with a definition of the attribute and problem statement, followed by a high-level recap of the foundational analysis and key insights, as presented in the [September 2023](#) and [October 2023](#) attributes workshops. Following that is a directional recommendation of how to approach possible solutions, including what MISO recommends *not* to do. Lastly, each section contains details of the proposed roadmap of solutions, including related work underway at MISO.

MISO conducted foundational analysis for each priority system attribute to guide the solution selection and prioritization. The analysis relied on existing and vetted datasets, methods, and software, which were augmented to meet the specific needs of the study. Generally, the analysis compared a representation of today's system (e.g., planning year 22-23) to forecasted out-year system conditions derived from MISO's Future 2A expansion.³

³ Futures portfolio are based on Scenario 2A in MISO, [MISO Futures Report Series 1A](#), November 2023.



System Adequacy

NERC defines adequacy as the “ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.”⁴ MISO’s attributes team further framed the system adequacy attribute as the ability of a resource portfolio to meet capacity and energy demand for a wide range of system conditions, with the expectation that unserved demand does not exceed a predetermined criteria.

MISO focused the 2023 system adequacy analysis on the risk factors expected to be most acute in the near term: availability, energy assurance, and fuel assurance (Figure 4). Availability is the consistent and predictable ability to call on capacity at the time of need. Energy assurance is the ability of the system to adequately manage and deliver energy supply on a 24 hour, seven days a week basis, especially in the presence of variable-energy or energy-limited resources. Fuel assurance is the ability for resources to access primary or backup fuel for electric power production at the time of need. These aspects of system adequacy are interrelated. For instance, extreme weather can drive widespread performance issues across all three risk factors.

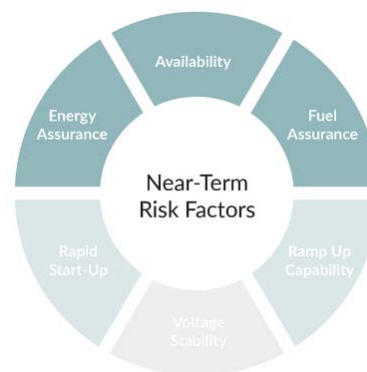


Figure 4: System Adequacy near-term risk factor focus areas

RECENT AND PROPOSED RESOURCE ADEQUACY REFORMS ADDRESS THE FUNDAMENTALS

The modernization of MISO’s resource adequacy construct is well-underway with recent and proposed changes to incorporate current industry best practices and address shifting risk. MISO’s recently implemented seasonal Planning Resource Auction (PRA) better acknowledges seasonal risks and resource capabilities throughout the year. The current accreditation methodology, approved by the Federal Energy Regulatory Commission (FERC) in 2022, also aligns the accreditation of thermal resources with their availability in the recent highest risk periods.

The proposed next step for resource adequacy reform is to credit all resources using a combination of the Direct Loss of Load (DLOL) method⁵ at the class level and the previously defined Resource Adequacy hours⁶ at the unit level. Load modifying resources (LMR) and other emergency resources are currently excluded from the proposed accreditation changes (DLOL method), due to their status as emergency only. MISO is working on a parallel initiative for these resources.

When MISO implements these proposed reforms, the fundamental components will be in place to address the energy transition. MISO recommends improvements to the underlying model to fully capture attribute risk.

⁴ NERC, [Glossary of Terms Used in NERC Reliability Standards, March 2023](#).

⁵ DLOL is an accreditation methodology that examines the contribution of a resource to the system during times of risk, represented by loss of load hours. MISO, [Resource Accreditation White Paper](#), November 2023.

⁶ FERC. Docket No. [ER22-495-002](#), February 16, 2023.



SYSTEM ADEQUACY REQUIRES EXTENDING LOSS OF LOAD EXPECTATION MODELING

Today, MISO's Loss of Load Expectation (LOLE)⁷ modeling incorporates an optimized planned outage schedule and randomly drawn forced outages based on historical unit-level outage data. Additionally, an extreme cold weather outage adder is modeled, which approximates weather-dependent outages using zone-specific, fixed outage profiles based on historical outage data during extreme cold temperatures. As the system's fleet continues to evolve, it is necessary to better understand and quantify the impact on the system risk from weather-related drivers, such as outages related to fuel unavailability, mechanical failure, and a breakdown of gas/electric coordination. To increase visibility into the weather-dependent risk drivers, it is important to explore the impact of fuel and non-fuel related outages on the LOLE framework. It is also key to acknowledge the regional implications of transfer limits between different geographical locations as the resource mix becomes more diverse.

The primary objective of the 2023 system adequacy attribute work was to develop a method for measuring emerging risk factors (availability, energy, and fuel assurance) and quantify their impact on system-wide accreditation and requirements. Two study cases were defined: (1) business-as-usual, and (2) enhanced risk assessment. The enhanced risk assessment case was designed to assess the impact of risk factors related to the delivery of energy during more constrained conditions (transfer limited). The enhanced risk assessment also extended the approach followed in the business-as-usual case for capturing weather-dependent outages, by modeling these as a function of the installed capacity. The two study cases were analyzed using three evolving resource portfolios: today, 2027, and 2032.⁸

The impacts of these risk factors were quantified by the resulting changes in accreditation and requirements between the two cases and across portfolios. The outcome of this assessment, which helped inform the solutions hypothesis, offers three key insights.

Resource Adequacy Terms:

- “Loss of load Expectation” (LOLE): Expected or average number of days during a given time period for which the available generation capacity is insufficient to serve demand
- “Loss of load Hours” (LOLH): Expected or average number of hours during a given time period where system demand will exceed the generating capacity
- “Expected Unserved Energy” (EUE): Amount of demand (measured in MWh) that the system will not meet during a given time period, averaged across a wide range of system conditions
- “Conditional Value at Risk” (CVaR): Expected unserved energy over the X% worst system conditions

⁷ IEEE reference for a comprehensive description of [LOLE resource adequacy terms](#).

⁸ Futures portfolio are based on Scenario 2A in MISO, [MISO Futures Report Series 1A](#), November 2023.



INSIGHT: Accreditation aligns with the risk distribution, regardless of the underlying sources of risk modeled, and tracks the contribution of individual resources

The proposed accreditation method (DLOL) aligns availability and need in the planning horizon at the class level. As the generation fleet evolves, the timing, volume, duration, and frequency of loss of load events are expected to change (Figure 5).⁹

The bulk of the risk moves away from the summer gross peak load and distributes across other seasons (Figures 5 and 6). In 2027, the risk is expected to balance between the summer and fall seasons. In 2032, the risk concentrates in the winter, driven by electrification and weather-dependent capacity.

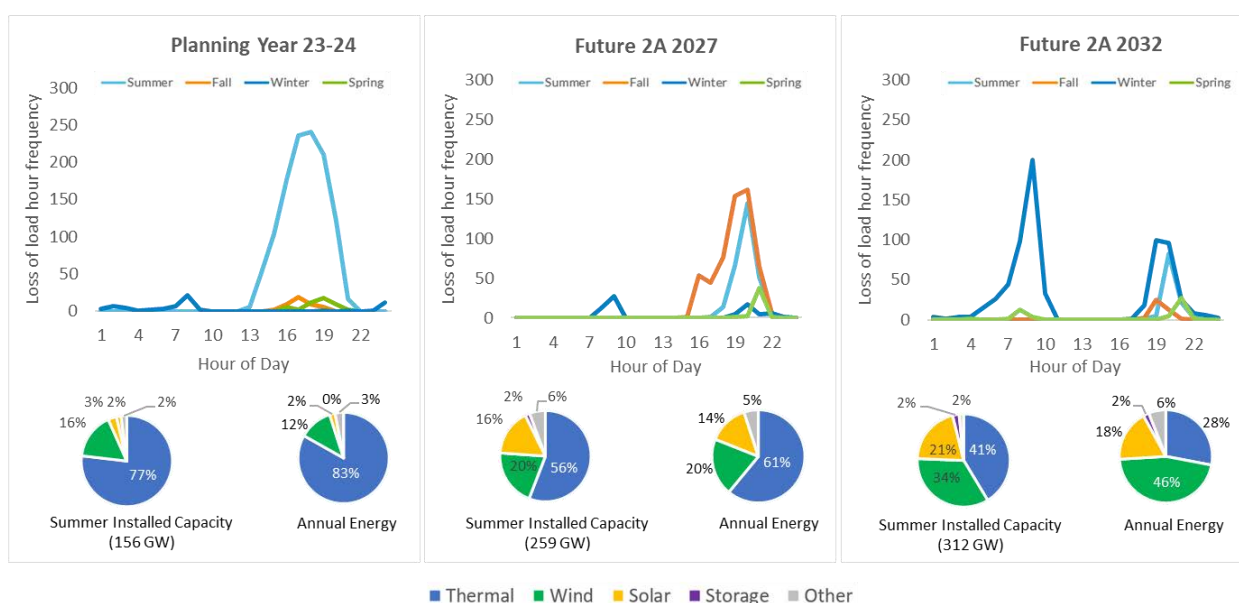


Figure 5: Evolution of risk distribution in future portfolios

These shifts in risk over time impact the accreditation of resources and system requirements, as both rely on the underlying LOLE model. Figure 6 illustrates the changes in summer accreditation and risk distribution from the business-as-usual LOLE simulations. The reduction in wind and solar accreditation in later years is driven by the shift in risk towards twilight hours. The slight increase in storage accreditation is due to the shorter duration and smaller magnitude events in the 2032 portfolio.

⁹ A summary of all metrics is included in section A.4.1 of the [Technical Appendix](#).

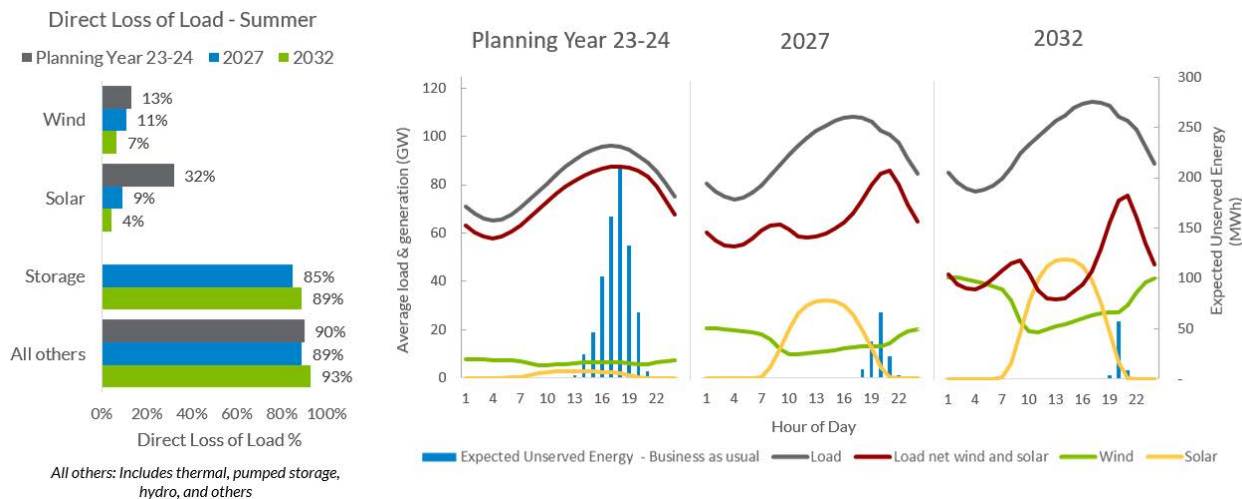


Figure 6: On the left, estimated summer season, class-level DLOL accreditation values for the three portfolios (today, 2027, and 2032) by fuel type. On the right, summer diurnal plots from the LOLE simulations showing average load, net load, and renewable generation for each hour.

Figure 7 shows the forward-looking accreditation results for the winter season. The changes in wind and solar accreditation are small, as the risk distribution in the winter season is concentrated in nighttime hours. The 2032 portfolio shows events that are longer in duration, more severe, and with a higher frequency (multiple events per day). This results in a lower accreditation for energy-limited storage resources¹⁰, as their ability to mitigate risk is proportional to their state of charge at the beginning of the event and total energy available.

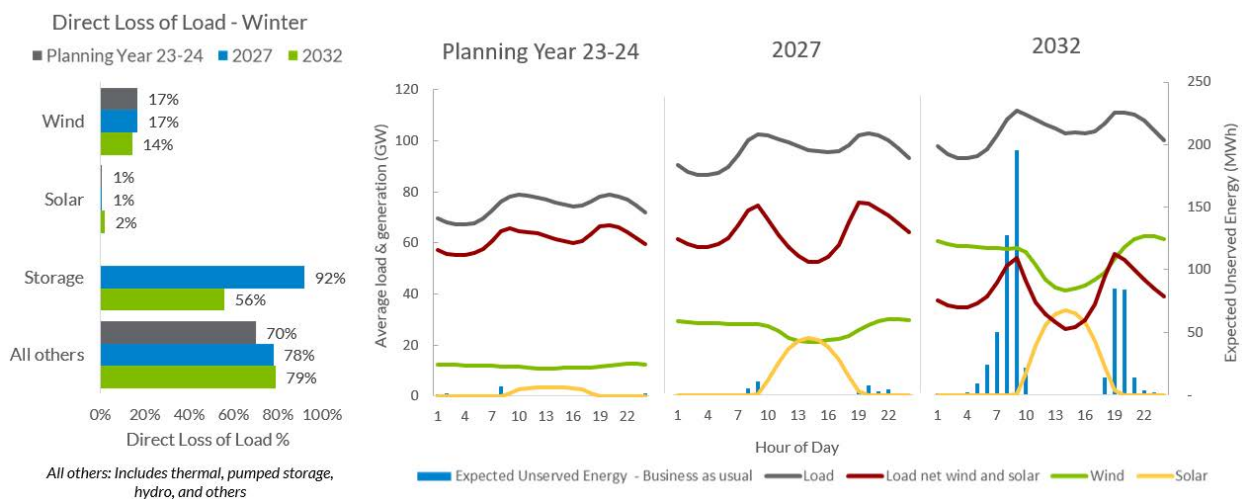


Figure 7: On the left, estimated winter season, class-level DLOL accreditation values for the three portfolios (today, 2027, and 2032) by fuel type. On the right, winter diurnal plots from the LOLE simulations showing average load, net load, and renewable generation for each hour.

¹⁰ Modeled as 4-hour resources in this analysis.



Capturing these interactions and changes in risk patterns are key to the development of a robust accreditation methodology that will serve existing and future portfolios, and the analysis demonstrated that robustness. The full set of forward-looking accreditation results are included in section A.4.1 of the [Technical Appendix](#).

INSIGHT: The acknowledgment of weather-dependent outages and deliverability captures additional risk factors that are projected to appear in future portfolios

The incorporation of weather-dependent outages increased winter LOLE. The incremental winter risk in 2027 and 2032 are primarily driven by weather-dependent correlated outages. Although both portfolios included the same planned retirements, the addition of “flex” units¹¹ resulted in additional correlated outages in 2027 and 2032. The concentration of long-duration events in extreme weather conditions, such as winter storm Uri in 2021, highlighted wind capacity impacts.

The incorporation of the regional directional transfer (RDT) limits between MISO North/Central and South in the enhanced risk assessment case increased LOLE across all seasons compared to the business-as-usual case (Figure 8). Risk increased the most in spring and winter in 2027 when the RDT constraint was added, while in 2032 risk increased the most in winter. These increases in LOLE show that the inclusion of transmission constraints into the model captures underrepresented transfer limitations between the two MISO regions. The modeling of non-firm external transactions was kept unchanged in the business-as-usual and enhanced risk assessment cases.¹²

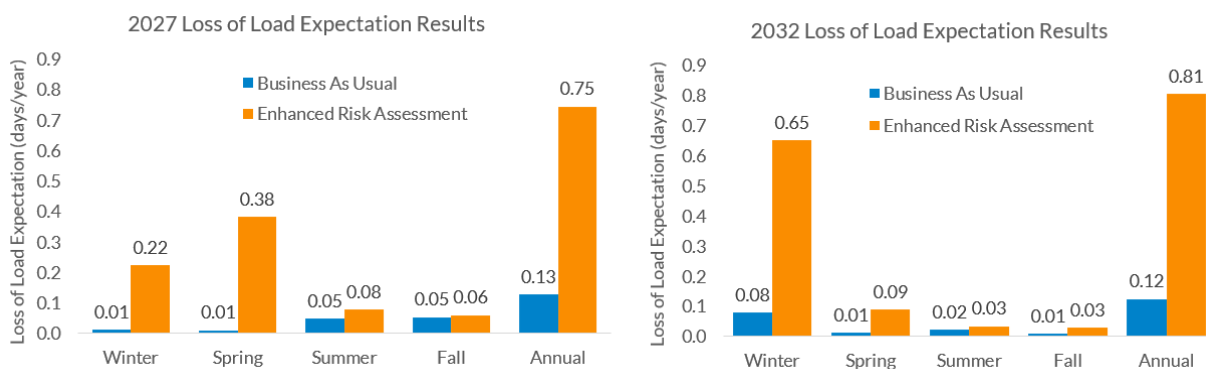


Figure 8: Seasonal LOLE results for the business-as-usual and enhanced risk assessment cases when both at the same adjustment.

The inclusion of the RDT constraint also had an impact on wind and storage accreditation values; the difference in DL0L between the business-as-usual and enhanced risk assessment cases for two resource classes (wind and battery storage) are shown in Figure 9. These accreditation changes can be attributed to transfer limit constraints when the RDT limit is enabled. It also highlights the difference in resource mixes

¹¹ MISO, [MISO Futures Report, Series 1A](#), November 2023.

¹² Modeling of non-firm external transaction was based on historical net-scheduled interchange between MISO and external regions, followed resource adequacy base business practices. More details are available in section A.2 of the [Technical Appendix](#).



between the North/Central and South in the model. Wind DLOL increased in the enhanced risk assessment cases because most of the wind capacity is in the North/Central region. However, most of the loss of load events were concentrated in the South region during periods of high wind availability in the North/Central, driving a higher MISO-wide wind accreditation. Similarly, storage DLOL decreased in the enhanced risk assessment cases because most of its capacity is in the North/Central region and was charging during loss of load events in the South region. Accreditation for the remaining resource classes did not change substantially between cases, with deltas under 3%. These values are shown in section A.4.2 of the [Technical Appendix](#).

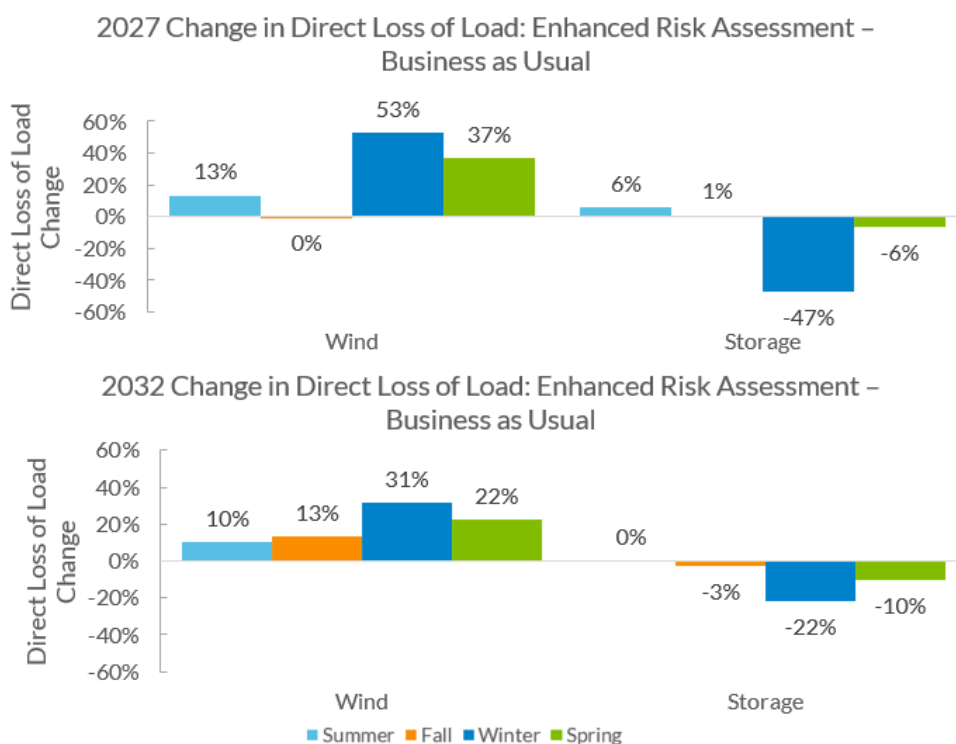


Figure 9: DLOL deltas between the enhanced risk assessment and business-as-usual cases for wind and battery storage resource classes when both cases are adjusted to seasonal LOLE targets.

MISO-wide planning reserve margin requirement (PRMR) increases when the RDT constraint is added to the model for both 2027 and 2032 (Figure 10). This change in the PRMR is due to the difference in fixed load adjustment to meet the 0.1 days/year LOLE target between the enhanced risk assessment and business-as-usual cases. The largest increase in the requirement for both years is in the winter season.

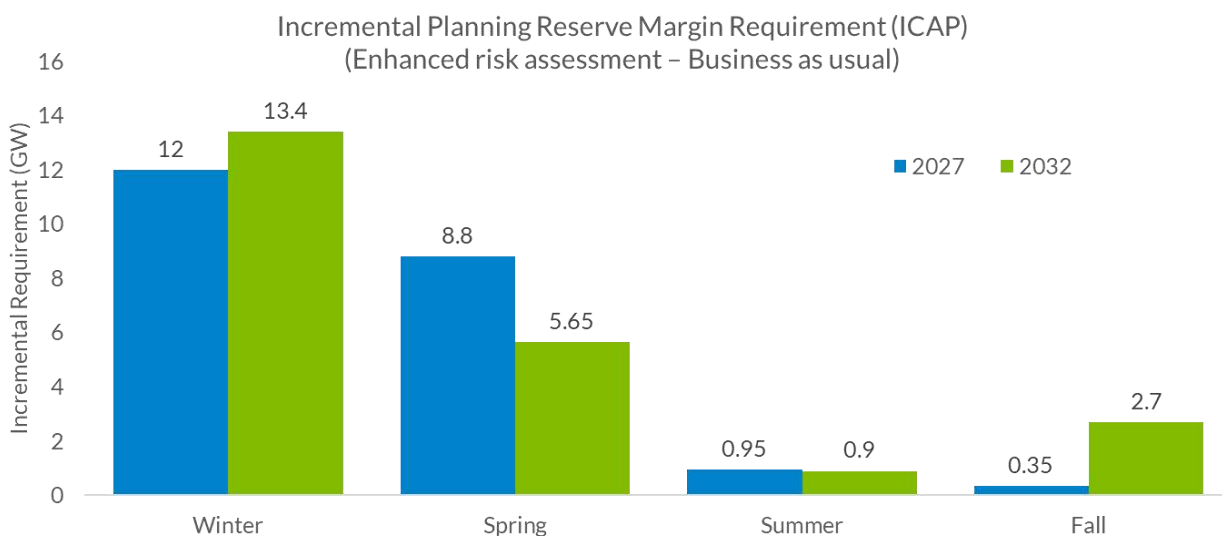


Figure 10: Incremental planning reserve margin requirement (PRMR) by season

INSIGHT: Initial system adequacy-focused flexibility analysis points to potential issues in 2032, additionally analysis is required to understand the implications

Season	PY22-23 Delta EUE (MWh)	2032 Delta EUE (MWh)
Winter	0	1794
Spring	0	6320
Summer	0	304
Fall	0	463

Table 1: EUE difference between business-as-usual and Adequacy-Flexibility analysis

The differences in expected unserved energy (e.g., delta EUE) between the business-as-usual and Adequacy-Flexibility analysis for the planning year 22-23 model and 2032 models are within the 300-6,320 MWh range (Table 1). For both models, the Flexibility analysis' Loss of Load Hours (LOLH) and LOLE matched exactly to the business-as-usual results of the corresponding model. The total EUE of all seasons matched exactly in the planning year 22-23 model, suggesting that flexibility is sufficient in the current portfolio.

In the 2032 model, MISO observed significant deviation in the results. Spring exhibits especially high EUE under the Flexibility constraints, followed by winter, fall, and summer. Figure 11 shows hours with high

To complete the flexibility analysis within the resource adequacy construct (adequacy-focused flexibility), additional operational data was added to the loss-of-load model, including maximum and minimum unit generation levels, up and down ramp limits, heat rates, and fuel costs. The most challenging week per season (in terms of highest expected unserved energy (EUE), net load, and net load ramping¹³) was selected for the planning year 22-23 and 2032 business-as-usual models.

The differences in expected unserved energy (e.g.,

¹³ Net load ramping is defined as the difference in net load between time periods t+1 and t.



netload driven by both Flexibility and business-as-usual EUE events in all seasons, while the Flexibility events show high variability in the netload ramping compared to the business-as-usual events. High rates of maintenance of thermal and flexible units in the spring had a major impact on the system's capability to mitigate the increased ramping up and down. This analysis did not include wind and solar generation curtailment, which could reduce ramping needs in the system.

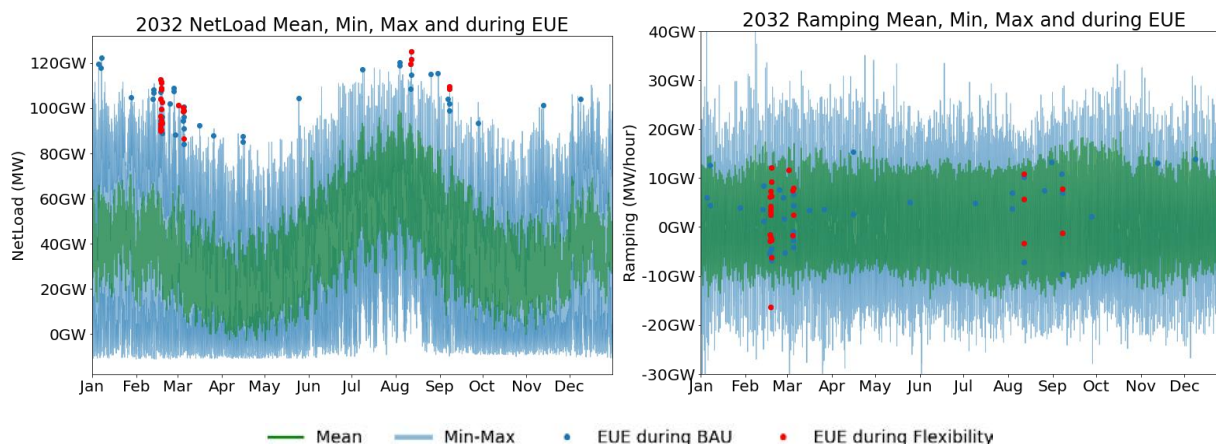


Figure 11: 2032 average, minimum, and maximum netload (left) and netload ramping (right). Blue and red dots signify netload and ramping at the event sample in business-as-usual and Flexibility

While this area of flexibility analysis within the resource adequacy construct presented some interesting results, further work is necessary to evaluate whether its inclusion in the system adequacy modeling is necessary. The proposed solutions in the operational adequacy space (see “Flexibility” section), coupled with the feedback loop between planning and operations, may be sufficient to ensure that flexibility issues are appropriately accounted for.

Find a detailed explanation of the full system adequacy analysis and results in sections A.3.3 and A.4.3 of the [Technical Appendix](#).

SYSTEM ADEQUACY RISK IS BEST ADDRESSED THROUGH CAPACITY REQUIREMENTS, ACCREDITATION AND FORWARD MARKETS

MISO recommends a continued focus on one market clearing product – capacity – because complex interactions between different resource types make it impractical to discretely quantify a specific amount of availability, energy duration, fuel requirement or related adequacy attributes. MISO’s analysis finds that the existing combination of capacity and reserve requirements, accreditation, and forward markets provide a sufficient framework to ensure system adequacy. Emerging attribute-related risk factors should be addressed by continually assessing and acknowledging operational risks through constraints in MISO’s risk models, the results of which will be reflected in accreditation and reserve requirements.

Additionally, MISO should focus on incentivizing good fuel assurance practices in three ways. (1) MISO will continue to apply and refine the “RA Hours” methodology to reward resources with sufficient fuel to maintain availability during times of risk with higher accreditation values. (2) MISO will create additional incentives through accreditation for resources with higher levels of fuel assurance (dual fuel, etc.) by exploring the creation of a firm fuel class, or similar, with qualification and ongoing operating performance



requirements. (3) MISO will continue the practice of multi-day commitments as needed through the Reliability Assessment and Commitment process and rely on the IMM to recognize extenuating circumstances in the cost of securing fuel.

WHAT NOT TO DO NOW

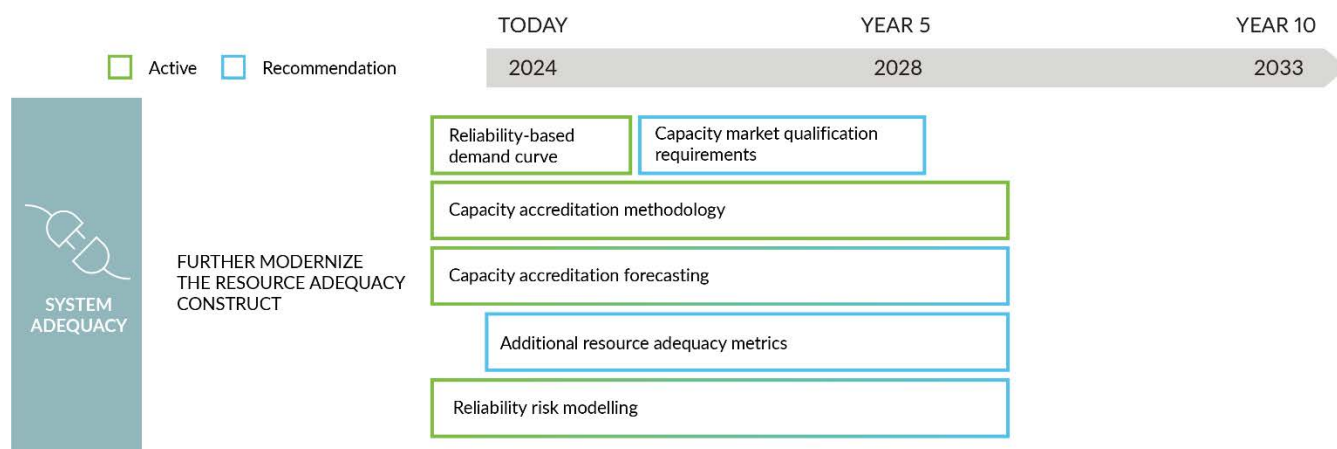
The *Attributes Roadmap* does not recommend new discrete capacity products (e.g., ramp capacity, energy reserves, or winter fuel programs). Capacity products outside the current construct may suppress energy and capacity prices. Additional products will increase complexity, requiring careful operational design, high implementation cost, and long implementation time with highly uncertain benefits.

MISO has also determined that there is currently no need to create an accelerated path for resource interconnection to account for attributes. Adequacy risks are regional in nature and more fully accounted for within the proposed resource adequacy enhancements. MISO continues to be focused on reaching the target queue timelines for all resources, which align with development timelines such that an accelerated path is not expected to result in earlier in-service dates.

There is no current need to account for the system adequacy attribute in the retirement (Attachment Y) programs because, again, adequacy risks are regional and better addressed through resource adequacy enhancements. Unless a policy need arises, Attachment Y is designed to be a stop-gap measure and is an insufficient mechanism to retain resources long-term or send long-term investment signals.

Lastly, MISO does not recommend taking broad action to secure forward gas supplies either through a multi-day market or forward fuel procurement. MISO will continue to commit gas and other resources beyond the day ahead market for limited reliability reasons and will explore improvements to that process and associated tools.

ROADMAP: FURTHER MODERNIZE THE RESOURCE ADEQUACY CONSTRUCT





SYSTEM ADEQUACY: Further Modernize the Resource Adequacy Construct

Implement the **reliability-based demand curve (RBDC)** to signal the value of incremental capacity

Clarify **capacity market qualification requirements** to ensure that resources are available when needed

- Clarification of obligations for market participation (e.g., minimum availability criteria, minimum winterization criteria, DIR participation, non-emergency status, etc.) to account for characteristics that cannot be properly modeled

Enhance **capacity accreditation methodology** to value the availability of all resources when needed most

- Transition to the proposed methodology to consistently accredit all resources for their availability during periods of highest potential and realized system risk
- Create and maintain resource accreditation classes to acknowledge differing risk profiles from similar resource types
- Explore an update to the allocation of PRMR requirements to better align with times of risk
- Enhance load modifying resource (LMR) accreditation to better align with availability when needed

Forecast seasonal capacity accreditation values annually for future years to understand how future system trends affect resource class accreditation and requirements for the benefit of market participants

Explore and report **additional resource adequacy metrics** to improve the quantification of risk and resource contribution

- Include more granular resource adequacy metrics in the annual report, including EUE, LOLH, conditional value at risk (CVaR)
- Explore the characteristics of daily LOLE considering EUE and other reliability metrics as the driving metric in the PRM to understand the trade-off between them
- *Conditional:* Implement alternative resource adequacy metrics if the exploration reveals a more robust metric than daily LOLE

Improve **reliability risk modeling** to best characterize existing and emerging system risks

- Incorporate correlated weather impacts in the LOLE model to account for outages such as those caused by reduced variable energy production or large-scale fuel shortages that are not currently modeled
- Incorporate transmission modeling in the LOLE model to account for increasing regional energy transfer requirements that result from the changing fleet and update downstream processes (e.g., accreditation, requirements) to utilize the enhanced geographical resolution
- Improve modeling of storage, energy-limited resources, and demand-based resources to properly capture their operational constraints and their additional contributions to the system (e.g., energy balancing, ancillary services)
- Explore implications of climate change for both supply and demand to improve load forecasting as well as address uncertainties and high-stress grid conditions
- Establish a feedback loop to analyze operational risk to identify diverging trends and continuously realign the risk model

Table 2: Hypothesis solutions roadmap to proactively address system adequacy attribute risk by further modernizing the resource adequacy construct.



SOLUTION: Implement the reliability-based demand curve to signal the value of incremental capacity

MISO's reliability-based demand curve approach¹⁴ seeks to provide more stable price signals for markets participants and regulators to provide the necessary capacity supply, while avoiding excessive infrastructure development. In September 2023, MISO filed tariff changes to FERC that include the following key elements:

- System-wide and sub-regional demand curves
- Incorporation of net cost of new entry and the marginal reliability impact resulting from MISO's loss of load modeling, that together determine the value of capacity
- A reliability-based demand curve opt-out provision for states that choose to not participate in the PRA

Should FERC approve the proposed changes, MISO aims for implementation in the 2025 PRA for Planning Year 2025-2026.

SOLUTION: Clarify capacity market qualification requirements to ensure that resources are available when needed

Characterizing system needs and risks through LOLE modeling is one of the pillars of MISO's resource adequacy construct, but modeling adjustments may not always be sufficient to fully capture systems risks for any number of reasons (e.g., lack of necessary data, software, or computational limitations, etc.). In limited circumstances, MISO recommends establishing new requirements or obligations for capacity market participation, such as minimum availability criteria, minimum winterization criteria, dispatchable intermittent resource (DIR) participation, and non-emergency status. MISO will work with stakeholders to develop these requirements when these attributes cannot be properly ensured through the accreditation construct, LOLE modeling, and capacity market.

SOLUTION: Enhance the capacity accreditation methodology to value the availability of all resources when needed most – and forecast seasonal accreditation values annually for future years to understand how future system trends affect resource class accreditation and requirements for the benefit of market participants

Resource accreditation should reflect the availability of resources when they are most needed. Significant growth of variable, energy-limited resources in the MISO footprint, along with changing weather impacts and operational practices, are shifting risk profiles in highly dynamic ways with implications to resource adequacy and planning. MISO is currently proposing to align capacity accreditation with system risk to estimate the capacity contribution of MISO resources.¹⁵ This approach measures resource accreditation during periods of both highest potential and realized system risks consistently across all resource types. MISO's plan includes a three-year transition for the implementation.

¹⁴ MISO, [Reliability Based Demand Curves Conceptual Design White Paper](#), September 2023.

¹⁵ MISO, [Resource Accreditation White Paper](#), November 2023.



As part of the proposed approach, resources are grouped into classes. In the future, MISO should create and maintain resource accreditation classes to acknowledge differing and evolving risk profiles from similar resource types. For instance, there may be a need for increased granularity to acknowledge diverging availability from resources sited in different areas of the MISO footprint or with different levels of fuel assurance. Resource classes should evolve to better track sources of system risks and better represent how to reflect resources characteristics contributions to system adequacy.

Like the proposed capacity accreditation reform, MISO should explore an update to the allocation of PRMR obligations to better align with times of risk. Transitioning the allocation process from seasonal gross peak to risk-based values would create incentives for LSEs to shift load toward those times of the year that are most effective at reducing the potential for unserved energy.

The current capacity accreditation proposal will be applied to all system resources, except for emergency-only resources such as Load Modifying Resources (LMRs). MISO is currently designing improvements to LMR accreditation.¹⁶ The reforms will determine appropriate capacity credits for LMRs that more closely align with their availability and account for specific characteristics (such as notification time), improve LOLE modeling assumptions to align with operations, and align assumptions of resource adequacy processes to facilitate efficient use of LMRs' potential.

Forward-looking accreditation values are an important input in making long-term investment decisions. MISO recommends providing regular forecasted seasonal capacity accreditation values and PRMR estimates to stakeholders, published within existing recurring reports (e.g., Regional Resource Assessment). Ongoing review of these forecasts will allow MISO and market participants to identify and prepare for emerging trends in advance of the capacity market binding period.

SOLUTION: Explore and report additional resource adequacy metrics to improve the quantification of risk and resource contribution

Most MISO resource adequacy processes rely on a single metric - daily LOLE - measuring either expected loss of load in days/year or days/period.¹⁷ As the system risks evolves, so will the nature of risks. Relying on a single metric does not convey the full picture of reliability.¹⁸ Outages with different characteristics such as outage time or magnitude may be considered equally under the 1-outage day in 10-year metric.

While MISO recommends the Planning Resource Margin (PRM) continue to be determined using a single reliability metric, MISO should regularly publish more granular resource adequacy metrics to inform planning decisions and enable members to determine their own needs. These additional metrics may include expected unserved energy (EUE), loss of load hours (LOLH), or conditional value at risk (CVaR). MISO should create a roadmap focused on the need to reform the resource adequacy criterion considering the range of more granular resource adequacy metrics.

¹⁶ MISO, [Resource Adequacy Subcommittee \(RASC\) stakeholder process](#).

¹⁷ G. Stephen, *et al*, "[Clarifying the Interpretation and Use of the LOLE Resource Adequacy Metric](#)", 2022 17th International Conference on Probabilistic Methods Applied to Power Systems (PMAPS), June 2022.

¹⁸ Energy Systems Integration Group, [Redefining Resource Adequacy for Modern Power Systems](#), 2021.



After the exploration of additional reliability metrics is complete, MISO should also explore the implications of replacing daily LOLE as the driving metric in the LOLE Study and PRM process. The implications of using other metrics should be understood, including their interdependencies and robustness as the system evolves. Should this exploration reveal one or more metrics that are more robust than daily LOLE, MISO should implement alternative reliability metrics to drive PRMR and accreditation processes.

SOLUTION: Improve reliability risk modeling to best characterize existing and emerging system risks

Current risk modeling performs a Loss of Load Expectation (LOLE) analysis to calculate the Planning Reserve Margin (PRM) requirement to ensure that MISO resources can reliably meet demand. As the fleet transitions, a broader set of conditions must be considered to maintain reliability. MISO recommends several LOLE model improvements to ensure that existing and emerging system risks are more accurately accounted for:

- Incorporate correlated weather impacts to the system. Resource outages caused by reduced variable energy production or large-scale fuel shortages are two examples of risks not currently modeled by MISO.
- Incorporating transmission modeling to recognize that the changing fleet will be enabled by increasing regional energy transfer. The risks related to events limiting transmission should be included in future models.
- Improvements to the representation of emerging technologies¹⁹ and emergency resources to properly capture their operational constraints and additional contributions to the system (such as energy balancing or ancillary services).

As the model improves, results of downstream processes (such as accreditation or requirement setting) will be impacted. Some of these recommendations may have significant implications in those processes. For example, incorporating transmission constraints in the LOLE model will provide additional insight on the locational nature of risk, which could be used to enhance zonal requirements.

Additionally, MISO is currently working to improve its load forecasting system by developing probabilistic forecasting capabilities, including expanding the available load forecasting models and weather scenario data available to the forecasting team. This additional information will allow load forecasts to better capture weather risk associated with climate change. MISO is working to evolve planning assumptions and tools that can address uncertainties and high-stress grid conditions through scenario-based planning that considers a broad range of plausible long-term futures as well as real-world system conditions, including challenging and extreme events.

Finally, MISO recommends establishing a feedback loop to continuously realign the risk model with operational risks. Work is underway to improve operations planning study models for greater consistency with Energy Management System (EMS) models.

¹⁹ Some emerging technologies present new challenges in resource adequacy modeling because their ability to contribute of the system depend on factors beyond whether the units is available or is experiencing an outage. For example, battery storage generation depends on its state of charge and load modifying resource may have limitation on the frequency and duration on their activation.



PLANNING HORIZON ANALYSIS NEXT STEPS

The work of modeling enhancements and understanding their impact on reliability and accreditation will be ongoing. Future investigations into planning horizon attribute risks and solutions could target questions such as:

- How can the LOLE modeling process be enhanced by including additional risk factors in the planned maintenance scheduling?
- What level of transmission granularity is needed to acknowledge local risk factors?
- How should storage operations be captured in LOLE models?



Flexibility

Flexibility is the extent to which a power system can modify electricity production or consumption in response to changing system conditions, expected (*variability*) or unforeseen (*uncertainty*). Flexibility is crucial to operating the energy system where the supply and demand of energy needs to be balanced over different timescales. From an operating timeframe point of view the real-time balance is most crucial. MISO has a primary responsibility towards reliability and ensuring operations and markets can respond to changes in net load ramps over extended timeframes. MISO's energy and ancillary services market should enable adequate system attributes so that Operations is able respond in time and balance the system needs.

MISO's focus for the 2023 flexibility analysis was on the potential shortage of rapid start-up and ramp-up capabilities in future years (Figure 12). Rapid start-up is the ability to quickly start-up offline generation. Ramp-up is the ability to follow load and resource imbalance to track intra- and inter-hour load fluctuations within a scheduled period.

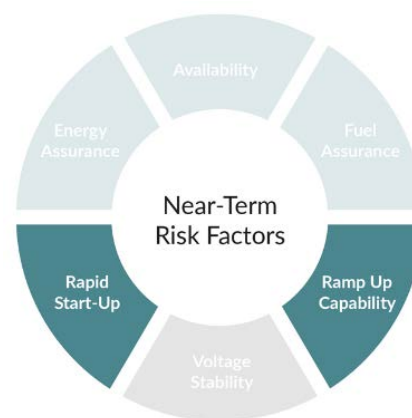


Figure 12: Flexibility near-term risk factor focus areas

MULTIPLE COINCIDENT SOURCES OF INCREASED VARIABILITY AND UNCERTAINTY DRIVE THE NEED FOR GREATER SYSTEM FLEXIBILITY

Historically, outages, load, and net scheduled interchange (NSI)²⁰ were the largest contributors of uncertainty and variability in managing the operating margin for the MISO region. MISO has historically depended on imports from neighbors who have had excess capacity. As the resource portfolio across the eastern interconnect evolves to include increasing amounts of variable resources, the complexity of managing operating margins will increase significantly and depending on import availability will become riskier.

Factors contributing to the increasing operational complexity, either due to greater variability or greater uncertainty include (1) increasing frequency and magnitude of system ramps, largely driven by the growth in renewable resources; (2) increased volatility in load forecasts due to changing weather and demand patterns; (3) more volatile generator outages, particularly related to aging of thermal units, extreme weather events, and fuel supply challenges; and (4) greater uncertainty of available energy at low margin hours, particularly in winter/spring evenings, as the fleet becomes more weather-dependent. These sources of increased variability and uncertainty drive the need for greater system flexibility in the future.

²⁰ Net Scheduled Interchange (NSI) is the net of MWs import and export schedules.



FOUNDATIONAL ANALYSIS

MISO's energy and ancillary services markets will play an important role in incentivizing competition for providing flexibility and other services that support energy delivery and reliability. MISO utilizes a two-settlement system comprising of a day-ahead market and a real-time market in which all products are simultaneously co-optimized. MISO needs to evaluate the ability of its market products to procure sufficient system attributes to maintain reliability without compromising efficiency under the evolving resource mix. This year's attributes analysis developed a simplified model of MISO's markets comprising the day-ahead unit commitment and real-time economic dispatch, which includes MISO's energy and ancillary services market products and rules.

The analysis centered around the simulation of stressed days to measure the potential unserved energy. For the current fleet, MISO chose historical extreme event days from different seasons for simulation. While for the future fleet, MISO selected potential stressed days in the future for comparison. In all simulations, MISO excluded operator reliability and emergency actions in order to provide a more meaningful comparison. Further, intraday commitments were excluded to keep the focus on the market constructs and not on MISO's unit commitment processes. A key limitation of these simulations was the exclusion of transmission constraints other than the RDT, but MISO hopes to address it in future analysis.²¹

The market simulations were carried out using a MISO-enhanced version of the Electrical Grid Research and Engineering Tool (MISO EGRET) that has implemented the main MISO energy and ancillary service market products and commitment rules.²² This tool was hosted in MISO Research and Development team's Advanced Simulation Environment, which provided the computational environment for running these simulations. This tool has previously been validated through extensive testing against MISO's production market system. For this year's analysis, data for the simulation was taken from day-ahead and look-ahead commitment (LAC) production cases for the two-stage market simulation. A new two-stage simulation framework appropriate for the attributes study was developed as part of this effort. The following key insights have informed the solutions hypothesis:

INSIGHT: Given the fleet transition the increase in net load variability and uncertainty will require new/enhanced market products and dynamic requirements that can achieve the greater flexibility needs on the operational timeframe.

A snapshot of one winter (January) and one summer month (August) across 2022, 2027, and 2032 indicates that the Future 2A fleet results in distinct new patterns for diurnal net load²³ profiles in both seasons (Figure 13).

²¹ The key assumptions used in this analysis are described in section A3.2 of the [Technical Appendix](#).

²² MISO-EGRET tool is described in the MISO, [Technical Appendix: RRA Assumptions and Methodology](#), from MISO, 2022 *Regional Resource Assessment*, November 2022.

²³ Net load is defined as gross load net of wind and solar generation.

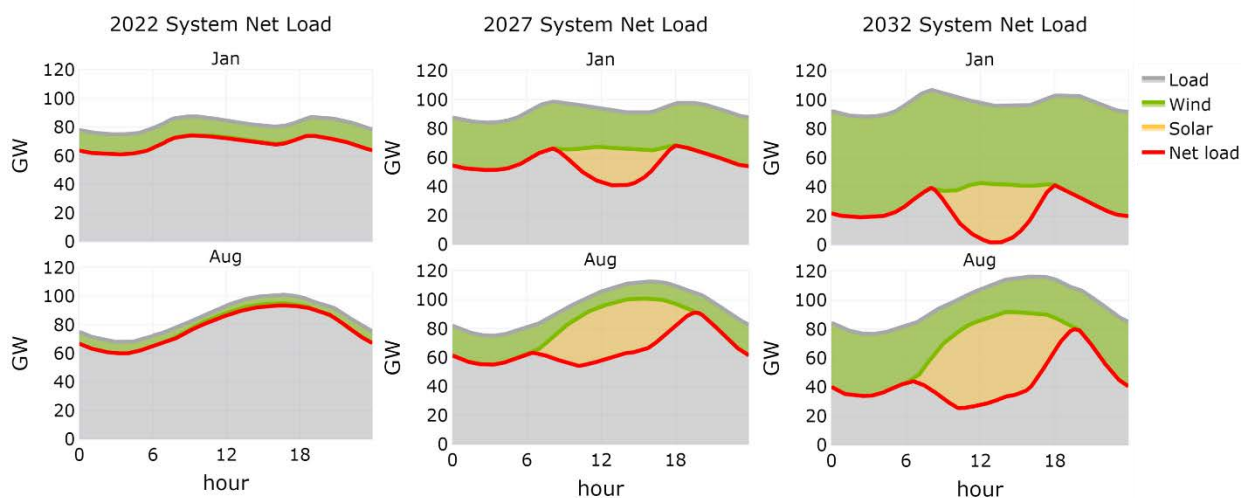


Figure 13: Monthly averages of diurnal net load components for January and August

With the generation fleet changes, the MISO winter diurnal net load pattern will begin to morph into the familiar “duck curve” shape,²⁴ with net load dropping around mid-day due to the increased presence of solar generation. In the evening as solar production decreases and electricity consumption increases, there is a significant increase in net load ramp-up. By 2032, the growth in wind and solar production in January results in even lower average net load around midday. In the summer months, the MISO system has historically seen a single daily net load peak in the late afternoon hours. By 2032, due to solar production, the daily net load peak is shifted to later in the day, into the post-sunset hours. Further the net load ramp needs in the evenings are projected to be high.

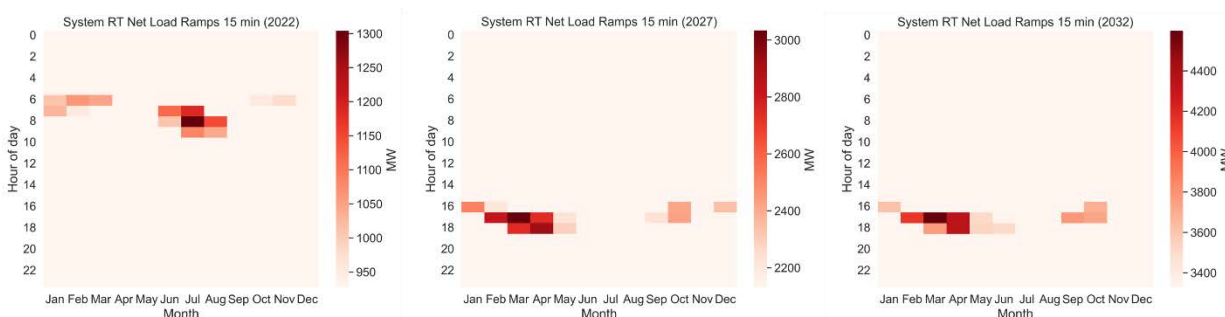


Figure 14: Highest 10 percentile of short duration net load up-ramps

Another way to visualize the ramping patterns is to look at the highest 10 percentile of short duration up-ramps (Figure 14). The quantitative change is significant. The maximum 15-minute up-ramp needs will be more than double by 2027 and 3.5 times by 2032 compared to 2022 levels.

²⁴ NREL, [Overgeneration from Solar Energy in California: A Field Guide to the Duck Chart](#), November 2015.



INSIGHT: The projected increase in risky days and lack of guarantees for availability of emergency and external resources increase the need to rely on demand side resources

The results from the Attributes market simulations of the historical events differ from the actual observations due to the assumptions described above. In reality, MISO Operations, acting in coordination with its neighbors, took many actions to manage the events successfully. The historical extreme event simulations show MISO's reliance on emergency resources as well as external resources, both of which are not guaranteed to be available in the energy market. For the historical summer event (Figure 15) in the base case the day-ahead commitment was inadequate to meet the real-time load due to a forecast error resulting in unserved energy. Additional scenarios were performed with different combinations of challenging conditions, such as the absence of LMRs or limited imports from neighbors (below the original maximum of approximately 13 GW systemwide net import amount). These cases increase unserved energy, with the worst result happening for the case with no imports into MISO and no LMR deployments (i.e., a "No LMR, No NSI" scenario). These scenarios highlight the importance of operator actions in maintaining reliability.

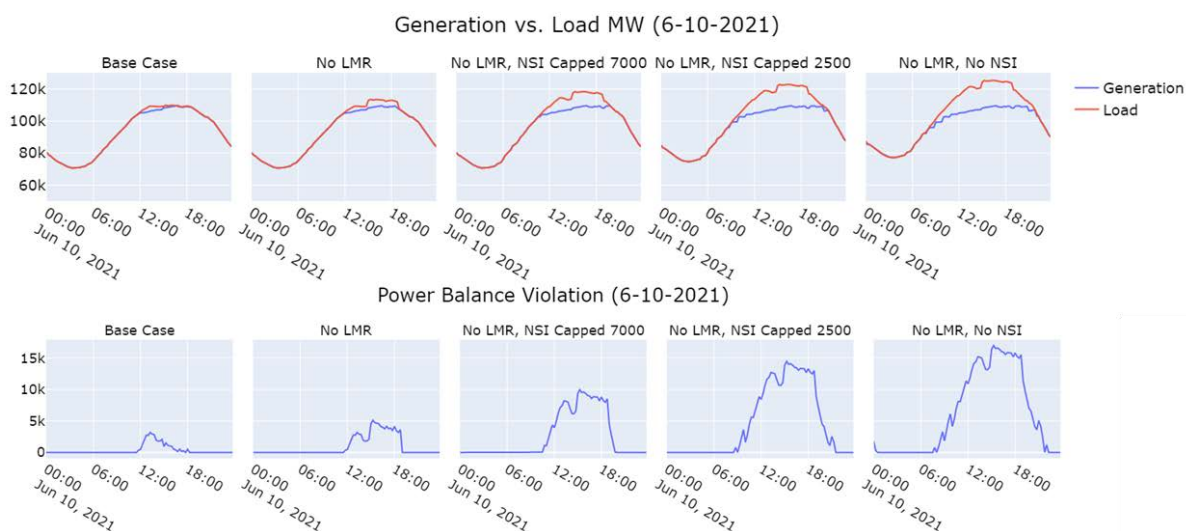


Figure 15: Simulation results for the summer event under different LMR and NSI scenarios

Over the past several years MISO has experienced several stressed days where it used emergency procedures as well as been dependent on imports from its Eastern Interconnect neighbors to manage challenging system conditions. Based on the results of this analysis these high-risk days are projected to grow in number and get more spread out across the year as the potential stressed days begin to show up in the shoulder seasons (Figure 16).

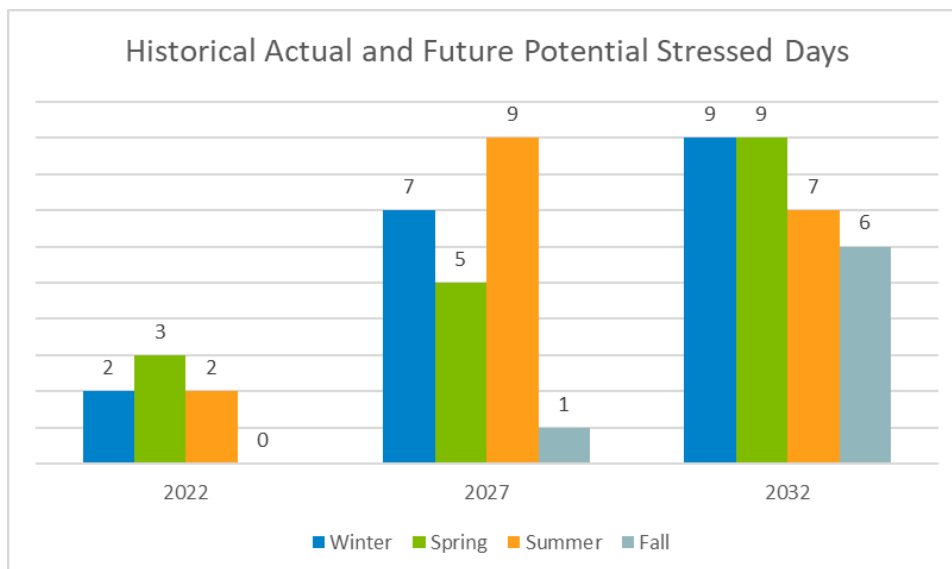


Figure 16: Historical events and future potential stressed days by season

With extreme weather, a greater number of high-risk days and the potential for climate change impacts, there are concerns for system reliability.

INSIGHT: The projected increase in duration and severity of events coupled with the retirement of conventional resources highlights the need for enabling the potential of emerging resources

The duration and severity of unserved energy events in a system with large penetration of renewables could increase since a large, sustained drop in renewable output could become the largest concern to manage in the operating timeframe. Figure 17 shows simulation results from various scenarios for a potential stressed day in Winter 2027. Figure 17a shows a small amount of unserved energy for the Base Case, because the Day-ahead commitment is inadequate to meet the Real-time load. Three individual stress scenarios are considered: a 50% drop in wind production throughout the day, a removal of external imports (MISO rather ends up exporting power), and a high-impact single gas pipeline outage. This last contingency, given Future 2A projected retirements, occurs in the MISO North/Central region and amounts to 6 GW. The wind-reduction scenario has the largest increase in unserved energy amongst the three cases. Finally, the worst-case event was simulated, where all 3 stress conditions occur on the same day.

Figure 17b illustrates how the use of quick-start units can address flexibility challenges. The worst-case event is used as the starting point and then quick start units are added until the unserved energy is mitigated. Quick start units are added beginning with the fastest group based on their lead-time of up to 20 min (i.e., 'quick 20 min'), and in later instances more units are added with increasing lead times of up to 60 min, 120 min etc. The mitigation occurs with units of lead-time of up to five hours.

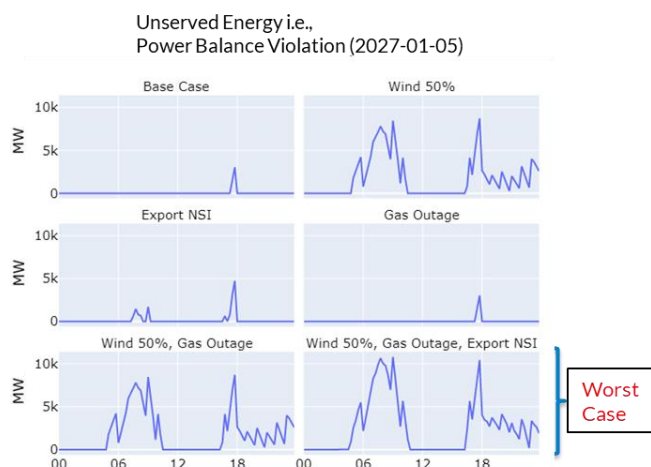


Figure 17a: Simulation results for base case and stressed scenarios for the winter 2027 event

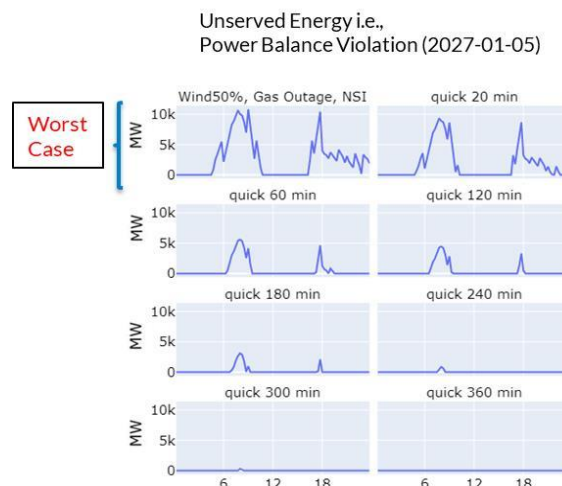


Figure 17b: Simulation results for worst stress case and mitigation using quick start units for the winter 2027 event

The Future 2A fleet assumes a new generator type known as the “flex” unit, which for this analysis is assumed to have the characteristics of fast combustion turbines. Thus, the overall quick start capacity in the 2027 and 2032 generation fleets is larger than in the current fleet.

Find a detailed explanation of the full flexibility analysis and results in section B of the [Technical Appendix](#).

FLEXIBILITY ATTRIBUTE RISK IS BEST ADDRESSED THROUGH MARKETS IN THE OPERATING TIMEFRAME

MISO recommends focusing the mitigation of flexibility risk on the operating horizon, specifically the real-time and day-ahead energy and ancillary services markets where key market design elements exist and are tested.

A focus on expanding current and new market products is needed to optimize flexible attributes and ensure availability and deliverability in real time on three fronts. MISO should (1) refine the quantities and formulation of ramping products (e.g., ramp, short-term reserves) based on operational experience and forward-looking studies, (2) explore implementing dynamic reserve requirements based on system risk, and more granular locational definitions to enhance deliverability of reserves, and (3) explore a new product for uncertainty management to reduce the need for “out-of-market” unit commitments for managing the day-ahead to real-time uncertainty.

Additionally, MISO should identify and address potential barriers preventing all resources from providing market services, allowing more resources to provide needed flexibility to the system. It should also create the capability to include flexible loads (e.g., controllable or price sensitive load) to provide market services.



WHAT NOT TO DO NOW

MISO projects, based on internal modeling efforts, that there will be sufficient resources to meet flexibility needs and therefore the development of discrete, flexibility requirements or derates in the capacity market is unnecessary at this time. Interactions between flexibility and capacity add excessive complexity to resource adequacy and may suppress capacity prices. Also, new capacity products do not directly increase utilization of that new flexibility characteristic in the operating horizon.

Additionally, the Forward Reliability Assessment Commitment remains MISO’s preferred method to inform market participants of upcoming needs. Efficacy is expected under future conditions making a multi-day market product unnecessary. Market participants are responsible for continuing to signal their needs to MISO.

Lastly, MISO does not currently recommend consideration of flexibility attributes within MISO’s resource interconnection or exit programs (Attachment Y) as flexibility risks are regional and will be fully accounted for within the expanded and new ancillary services products proposed in the roadmap below.

ROADMAP: FOCUS MARKET SIGNALS ON EMERGING FLEXIBILITY NEEDS



FLEXIBILITY: Focus market signals on emerging flexibility needs

- Implement **market pricing enhancements** to send price signals that reflect the value of resource availability
- Update the value of lost load, which sets the price cap in the energy market, to send better price signals during emergency and scarcity conditions
 - Change the operating reserve demand curve to improve the price incentive for flexibility
 - Update the transmission constraint demand curves for improving congestion management
- Implement **dynamic reserve requirements** to have better alignment between system conditions and risk
- Establish daily reserve requirements
 - Dynamic requirements for reserves (regulation, contingency)
 - Dynamic requirements for ramp capability product
- Implement **locational reserves** to improve deliverability of reserves
- Evaluate dynamic reserve zones to better align zonal definitions and system conditions
 - *Conditional:* Explore nodal reserves as an option to address the issue of reserve deliverability



Develop **new products for uncertainty and variability risk management** on the multi-hour time horizon to maximize the flexibility capabilities of existing resources

- Revisit participation model for flexible resources (potentially separate qualification for up and down ramp; additionally propose up and down regulation)
- Explore a new product for uncertainty management to manage flexibility needs and reduce out-of-market manual commitments
- Explore additional products to manage intra-hour netload variability (e.g., 30-, 60-min)

Table 3: Hypothesis solutions roadmap to proactively address flexibility attribute risk by focusing market signals on emerging flexibility needs.

SOLUTION: Implement market pricing enhancements to send price signals that reflect the value of resource availability

MISO's Resource Availability and Need (RAN) program identified concerns that market prices during historical emergencies and shortages have not reflected the scarce conditions. MISO's IMM has made multiple recommendations to improve MISO's emergency and scarcity pricing mechanisms. Efficient and transparent prices encourage Market Participants to make efficient operational decisions that can support and inform investment decisions. MISO is evaluating scarcity pricing during shortage events and near-term, mid-term, and long-term enhancements to various scarcity pricing mechanisms. In MISO's markets the locational marginal prices (LMP) are capped at the value of lost load, which is currently \$3,500/MWh. This value should be updated to ensure that valid prices are not truncated during reserve/transmission violations. MISO should evaluate updates to the operating reserve demand curve, to ensure that price signals are consistent with price formation principles. Along with updates to the value of lost load and operating reserve demand curve, the transmission constraint demand curve should be updated to ensure that MISO is able to manage congestion properly through price incentives during operating reserve shortages. The enhancements should send better price signals and manage growing uncertainty, incent flexibility, improve transparency, and address issues identified during recent emergency events. MISO is exploring additional enhancements to further improve price formation during emergency and scarcity conditions on a longer time horizon.

SOLUTION: Implement dynamic requirements to have better alignment between system conditions and risk

MISO co-optimizes energy and reserves leading to significant benefits for the footprint, including reduced costs and improved flexibility. Reserves are procured to provide backup capacity if necessary to deal with uncertainties and contingencies in the system that may impact reliability. With a transitioning resource portfolio, MISO is facing increasing variability and uncertainty in the availability of resources and system demand. MISO currently uses static reserve requirements. However, with higher levels of intermittent renewable resources MISO recognizes the need to move to dynamic reserve requirements so that reliability needs are better aligned with efficient market outcomes. As a first step, MISO looks to establish daily reserve requirements based on the forecasted risk level for the upcoming operating day. Future exploration should include intra-day dynamic reserve requirements derived from probabilistic net risk prediction as well as dynamic ramp product requirements to better manage ramp and uncertainties. In the future, with more wind and solar in the system, large drops in renewable production within 10 minutes could surpass the



single largest unit standard currently in use. This should require updating the contingency reserve requirements.

SOLUTION: Implement locational reserves to improve deliverability of reserves

Another key challenge associated with the increased uncertainty and variability is that of reserve deliverability, where the reserves may not be deliverable in real-time due to congestion. Historically to reliably deliver reserves, MISO utilized reserve zones in order to procure reserves in a dispersed manner. These reserve zones can be updated on a quarterly basis in conjunction with the network model updates. Currently MISO is using the reserve procurement approach on select constraints. MISO needs to implement improved locational granularity in its reserve products in order to ensure reserve deliverability. MISO should evaluate the possibility of dynamic reserve zones as a first step towards addressing this concern. Updating the reserve zones on a more frequent basis should improve market efficiency and system reliability, since there would be better alignment between zonal definitions and system conditions.

Conditionally, if additional reserve deliverability enhancements are required after the implementation of dynamic requirements, MISO should explore the procurement of reserves on a nodal basis in order to account for intra-zonal transmission congestion. The nodal reserve model could reduce the need for expensive out-of-market reserve disqualifications currently being utilized to manage the challenge of reserve deliverability.

SOLUTION: Develop new products for uncertainty and variability risk management on the multi-hour time horizon to maximize the flexibility capabilities of existing resources

Currently in MISO's market resources must be able to provide both upward and downward ramp to participate in the ramp capability product. This places limitations on some types of resources from participating in the ancillary services market. MISO should separate the qualification requirements for upward and downward ramp capability, which would allow more flexibility for different resource types to participate in the market. Further MISO should separate regulation into a regulation up product and a regulation down product to allow resources that are currently prevented from providing regulation due to congestion to provide regulation down. These solutions can expand the pool of resources which provide ancillary services.

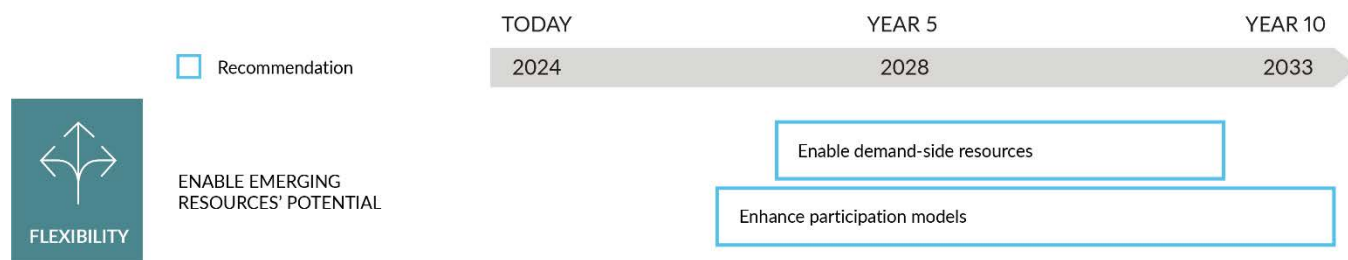
When there is a high degree of uncertainty operators may commit units "out of market" as insurance for the possibility of unexpected high net load. This uncertainty is expected to increase as the MISO fleet transitions to higher penetration of renewables. MISO should evaluate the development of a new uncertainty management product for managing these uncertainties. An uncertainty management product would allow "in market" procurement of units to meet uncertainty that would be committed when needed or released when not. This product could be provided by online and offline resources that are available to respond within certain response time (e.g., four hours lead-time). There may be a need for reserving long-lead units many hours in advance otherwise MISO might not have enough quick start resources to respond in time and avoid an unserved energy event. MISO should investigate how this product would work in conjunction with the current short-term reserve product.

Maintaining real-time power balance requires ramp flexibility from online units which has become more challenging as the proportion of intermittent renewable generation has increased. In 2016, MISO implemented a 10-minute ramp capability product to manage both variations (expected changes) and



uncertainties (unexpected changes) in the net load. The ramp capability product was designed to mitigate ramp shortages which were a common cause of price spikes. The current ramp capability product might not be able to manage extreme cases of ramping needs such as larger intra-hour ramps which are projected to occur as the penetration of renewables increases.²⁵ Hence MISO should consider additional products for longer ramp durations to manage the increasing intra-hour variability.

ROADMAP: ENABLE EMERGING RESOURCES' POTENTIAL



FLEXIBILITY: Enable emerging resources' potential	
Enable demand-side resources to enhance responsive load participation in energy markets	<ul style="list-style-type: none"> • Enable responsive load participation in energy markets • Enable visibility and controllability of Distributed Energy Resources (DER) in market operations
Evaluate options for enhancing participation models to allow all resources to provide market services to maximize capabilities	<ul style="list-style-type: none"> • Model multiple configuration resources in day-ahead market to increase flexibility and reduce commitment costs • Further optimize energy storage and co-located resources to leverage flexibility • Ensure commitment flexibility and management of days when net load approaches low values

Table 4: Hypothesis solutions roadmap to proactively address flexibility attribute risk by enabling emerging resources' potential.

SOLUTION: Enable demand-side resources to enhance responsive load participation in energy markets

Within MISO's footprint, demand resources that are used towards meeting the Planning Reserve Margin Requirement (PRMR) as part of the Planning Resource Auction (PRA) are known as Load Modifying Resources (LMR). LMRs include behind-the-meter generation and demand resources. In addition, MISO has a demand resource type known as Demand Response Resources that can provide service to the energy and ancillary services market. As of 2022, the majority of the approximately 12 GW of demand resources in MISO are classified as LMRs and only a small amount is classified as DRRs.

²⁵ MISO, [MISO's Renewable Integration Impacts Assessment \(RIIA\) study](#). Summary Report. February 2021.



One of the primary drivers of tightening operating margins is the accelerated retirement of thermal resources, which has increased the frequency of emergency declarations, with MISO relying more often on LMRs during these emergency events. In the past several years MISO has made changes to improve the availability and flexibility of LMRs for reliability such as reducing the maximum notification time requirement for LMR capacity accreditation from 12 hours to six hours. Maximum notification requirements should be further reduced to ensure maximum flexibility during emergency events.

MISO should increase its understanding of LMR capabilities and visibility into their granular locations to support more efficient and reliable commitment and dispatch. Part of the strategy may include leveraging emerging LMRs in the energy and ancillary services market. Moreover, there is a need for a detailed analysis of demand response participation across all MISO markets, which will inform a comprehensive strategy for better enabling load participation in MISO markets. Flexible price-responsive demand can provide many benefits, including mitigation of large net-load ramps, better management of contingency events, and enhanced market efficiency.

As the generation fleet transitions and new technologies enter the market MISO will need to evolve its operational and planning processes. Significant changes are expected in the coming decade on the demand side and supply side. One such coming transition focuses on distributed energy resources (DER). FERC Order 2222 requires DERs be allowed to participate in all aspects of Regional Transmission Organization (RTO) markets. This poses a number of challenges for MISO's operations, especially relating to visibility and controllability. MISO needs to consider the impacts of DERs on load forecasting. Further, MISO needs to implement distributed energy aggregated resources into the market engine, asset registration and settlements. Additionally, there is a need to identify and mitigate obstacles to customer readiness for DERs.

In total, MISO should find ways to increase participation of load resources in the MISO market and increase the flexibility they would contribute through MISO's various market products.

SOLUTION: Evaluate options for enhancing participation models to allow all resources to provide market services to maximize capabilities

With the advent of emerging resources, MISO should explore enhancing participation models to maximize the utilization of capabilities from these resources, along with those already present in the system. The harmonization of existing and upcoming capabilities throughout the energy transition will ensure smooth operations. The following are some examples that would contribute to this solution.

The multi-configuration resource model can enable significant flexibility from combined-cycle gas turbines (CCGT) across the MISO footprint. CCGTs with their ability for fast-ramping and quick response times could be a critical resource to addressing the variability needs. As the penetration of renewables increases the multi-configuration resource initiative can more fully exploit the capabilities of such resources to support the increasing flexibility needs of the system.

Large deployment of storage resources will present additional challenges in operations because, unlike traditional assets, their capabilities at any moment in time depends on their past actions. Charging and discharging decisions influence their state of charge at any moment, which influences the amount of energy they can generate or their ability to contribute to ancillary services. MISO should work to identify and mitigate any participation barriers for energy storage resources and co-located resources in MISO's markets that could help enable the additional optimization of such resources.



Finally, as the variable renewable penetration increases, the net load that needs to be covered by the remaining resources changes. Particularly, the minimum values of net load become lower, requiring a surge in the number of cycles for other resources between full generation and minimum generation levels. MISO should investigate minimum generation logic to ensure adequate commitment flexibility.

OPERATING HORIZON ANALYSIS NEXT STEPS

In addition to enhancements to its market products and requirements MISO should continue to focus on improvements to forecasting, visibility and commitment processes to ensure that MISO's operations are able to effectively manage challenging system conditions. One enhancement should include refinements to unit commitment tools so operators will increase their uptake of the Look Ahead Commitment (LAC) engine's recommendations.

Future investigations into operating horizon attribute risks and solutions could target questions such as:

- How should MISO design the new uncertainty management product given its sequencing with the short-term reserve?
- Should MISO implement a new intra-hour ramp product? This would be in addition to the existing 10-minute ramp capability product.
- How should MISO modify participation models which enable load modifying resources (LMR) in energy markets?
- How should MISO modify emergency pricing to avoid price suppression during events?



System Stability

System stability is the attribute of a power system that enables it to remain in a state of operating equilibrium under normal operating conditions and to regain an acceptable state of equilibrium after being subjected to a disturbance. MISO's focus for this year's analysis was on the voltage stability family of issues (Figure 18). Figure 19 shows a power system stability taxonomy often used in technical papers and how voltage stability relates to other system stability components.²⁶

Voltage stability refers to the ability of a power system to maintain steady voltages close to nominal value at all buses in the system after being subjected to a disturbance (e.g., loss of a transmission line) and is dependent on the ability of the combined generation and transmission system to provide the power required by the loads.^{27 28} Voltage stability is often thought of as load-driven rather than resource-driven, though resource characteristics effect voltage stability outcomes.

Find the detailed definition and explanation of MISO's current state voltage stability considerations, including transfer scenarios in reliability planning and contingencies in real time operations, in section C of the [Technical Appendix](#).

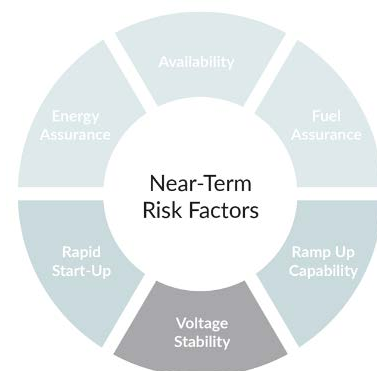


Figure 18: System stability near-term risk factor focus area

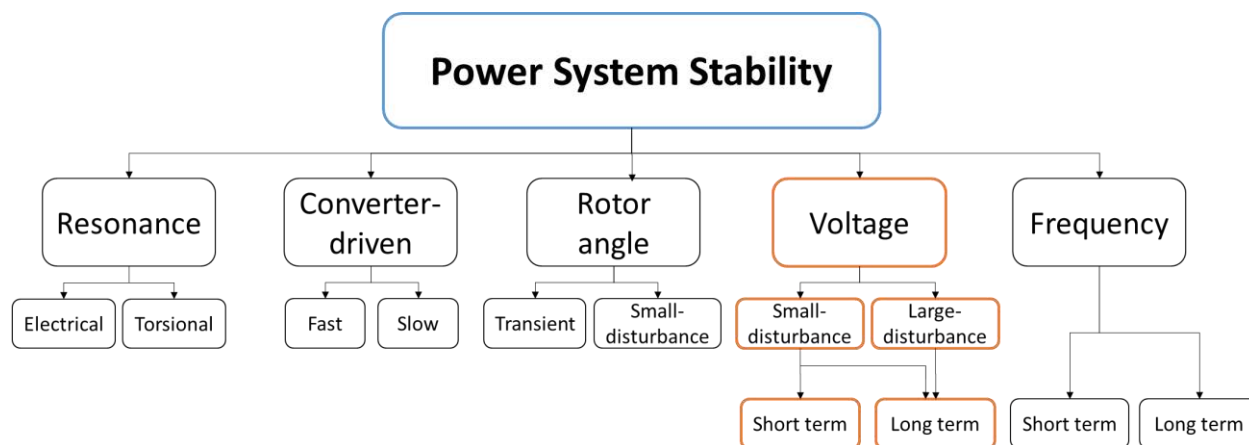


Figure 19: Taxonomy of power system stability considerations

²⁶ N. Hatziargyriou et al., "[Definition and Classification of Power System Stability – Revisited & Extended](#)," in *IEEE Transactions on Power Systems*, vol. 36, no. 4, pp. 3271-3281, July 2021.

²⁷ P. Kundur et al., "[Definition and classification of power system stability](#)," *IEEE Trans. Power Syst.*, vol. 19, no. 3, pp. 1387-1401, May 2004.

²⁸ T. Van Cutsem and C. Vournas, [Voltage Stability of Electric Power Systems](#). Norwell, MA: Kluwer, 1998.



VOLTAGE STABILITY-RELATED CHALLENGES ARE EXPECTED WITHIN FIVE YEARS

Several factors cause voltage instability, such as insufficient reactive power support, excessive loading, loss of transmission lines or generators, or inadequate voltage regulation. Emerging instability challenges are strongly correlated with today's energy transition trends, potentially leading to weak grid conditions under which instability issues materialize with greater frequency. Trends affecting voltage stability include:

- Synchronous machine retirements (e.g., coal-fired generators) reducing system strength and availability of reactive power
- Grid-following inverter-based resource (IBR) additions (e.g., solar generators) with software defined controls driving operating characteristics that are different from synchronous machines
- Generation siting that is further from load
- Changing dispatch patterns affecting synchronous machine fleet availability
- IBR model quality (verification and validation)

MISO's Renewable Integration Impact Assessment (RIIA) study indicated that voltage stability and inverter-based converter stability are among the first stability-related challenges the MISO system will likely face.²⁹ These challenges are projected to arise when renewable resources serve between 30% to 40% of MISO system annual energy. According to MISO's Future 2A resource expansion modeling, the 30% energy threshold may be reached around the year 2027.³⁰ Among the stability-related challenges studied in RIIA, not only are voltage stability challenges expected to emerge early in the energy transition, but the anticipated mitigation capital cost is expected to be the highest.

A lack of adequate voltage stability could result in loss of load in an area or protective system tripping of transmission lines or system components, potentially leading to cascading outages. Voltage collapse, one potential result from voltage instability, has been identified as a contributing factor in large scale blackouts across the globe, including Scandinavia (2003), the northeastern U.S. (2003), Athens, Greece (2004), and Brazil (2009). During the northeastern U.S. event in 2003, voltage instability resulted after multiple line tripping contingencies caused voltage fluctuations and reactive power deficiencies, causing generators and transformers to trip or malfunction.

ADVANCING VOLTAGE STABILITY ANALYSIS INCLUDED A NEW FOCUS ON EMERGING TOOLS AND GRID-FORMING INVERTER EFFICACY

This year's voltage stability analysis focused on (1) characterizing system strength using the short circuit ratio (SCR) approach, and (2) characterizing resources and stability limits using the dynamic impedance approach. The analysis characterized locations and potential severity of weak grid issues which often indicate potential stability challenges. Screening approaches, including those contemplated in this analysis, are used to identify areas and conditions that require deeper analysis. The two approaches are intended to bring visibility to a changing system and offer tools to account for resources' unique stability contributions in subsequent analysis.

²⁹ MISO, [MISO's Renewable Integration Impacts Assessment \(RIIA\) study](#). Summary Report. February 2021.

³⁰ MISO, "[Future 2A Expansion and Preliminary Siting](#)". Presented at LRTP Workshop, March 10, 2023.



The SCR approach is known to have limitations in areas of high inverter-based resource penetration as the metric is most appropriate when considering an IBR plant connected to a strong grid without the control interactions from other nearby inverters. While variations of the SCR metric account for interactions, modern inverter control topologies are beginning to decouple the IBR's fault contribution from system strength contributions, concepts that are tightly coupled in grids where synchronous machines are dominant.

The dynamic impedance method is relatively new, and MISO is working with industry partners to advance the understanding of its use and limitations. Using the approach to characterize grid-following IBR presented challenges, especially for large disturbances which resulted in severe voltage depressions. Using the approach for grid-forming IBR yielded promising results where both the large signal and small signal screening outcomes appear to be accurate. MISO is still investigating the method's efficacy for different applications based on other industry research evaluating similar approaches.^{31, 32, 33}

Grid-forming versus grid-following nomenclature:

- “Grid-following” (GFL) controls require a voltage source to maintain operation
- “Grid-forming” (GFM) controls create a voltage source and can operate in standalone mode

While these oversimplified terms are useful to communicate inverter capabilities broadly, control capability classification is more of a spectrum. For example, very fast grid-following controls provide some of the same support capabilities as grid-forming but are not capable of standalone operations.

INSIGHT: Localized pockets of stability challenges may materialize if emerging risks are not made visible and mitigated through controls and asset deployments

MISO's system strength screening analysis and results showed the highly localized and dynamic nature of potential voltage stability challenges, highlighting the need for improved visibility and proactive mitigation. System strength was shown to be affected by both long-term factors, such as a changing resource mix and transmission build, and short-term factors, like resource dispatch patterns across seasons. Using short circuit ratio (SCR) as an indicator of system strength, MISO completed a comparison analysis between future year and seasonal scenarios.

To consider the longer-term drivers, MISO compared the short circuit ratio (SCR) metric between a modeled 2025 summer peak and a modeled 2033 summer peak. Figure 20 shows the decrease (in red) or increase (in green) of the SCR metric, an indicator of system strength, between the two models and highlights the localized nature of system strength change.

³¹ Gu Y., Green T., “[Power System Stability with a High Penetration of Inverter-Based Resource](#),” in *Proceedings of the IEEE*, vol. 111, no. 7, pp. 832-853, July 2023, page 14, first paragraph.

³² J. Sun, “[Impedance-Based Stability Criterion for Grid-Connected Inverters](#),” in *IEEE Transactions on Power Electronics*, vol. 26, no. 11, pp. 3075-3078, Nov. 2011, page 1, last paragraph.

³³ S. Shah, et al., “[Impedance Methods for Analyzing the Stability Impacts of Inverter-Based Resources](#),” in *IEEE Electrification Magazine*, vol. 9, no. 1, pp. 53-65, March 2021, Section on “Large-Signal Impedance Analysis”.

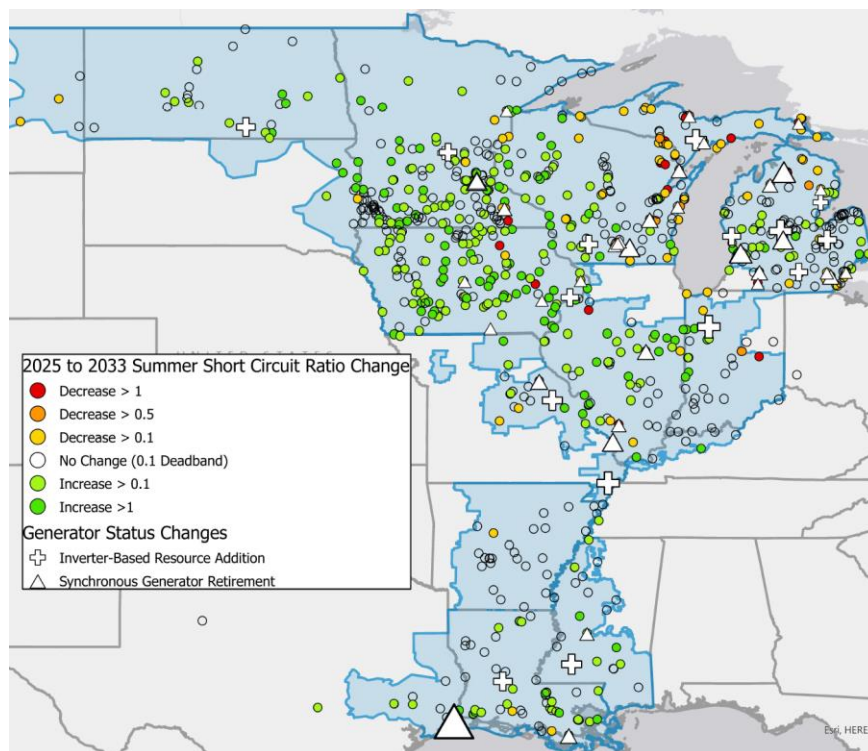


Figure 20: Change in short circuit ratio (SCR) between MTEP23 2025 summer peak and MTEP23 2033 summer peak cases³⁴

While this view shows the change in SCR as the resource portfolio evolves, the actual magnitude of SCR is crucial for using the metric as a screening tool. Additional details are contained in section C.3.2 of the [Technical Appendix](#) showing SCR magnitudes for the MISO Transmission Expansion Plan (MTEP) 2025, 2028, and 2033 cases. The [Technical Appendix](#) also contains sensitivities isolating the transmission and resource drivers over the planning horizon.

Shorter-term impacts on system strength are shown by comparing the 2025 summer model to the spring light load models (Figure 21), highlighting how voltage stability risks can change between seasons based on dispatch patterns. Different dispatch points warrant closer consideration, with a need to align planning models with actual operational conditions to better identify dispatch-related stability risks.

³⁴ Differences in resources between the MTEP23 2025 and MTEP23 2033 models could be attributed to resource additions, suspensions, outages, and retirements. For simplicity, these are labelled in Figure 20 as either an “Inverter-Based Resource Addition” or “Synchronous Generator Resource Retirement” to call out the locations of resource status changes driving SCR trends. However, the MTEP23 models used in this analysis are the same as those used in MISO’s MTEP processes, following applicable procedures in BPM-020.

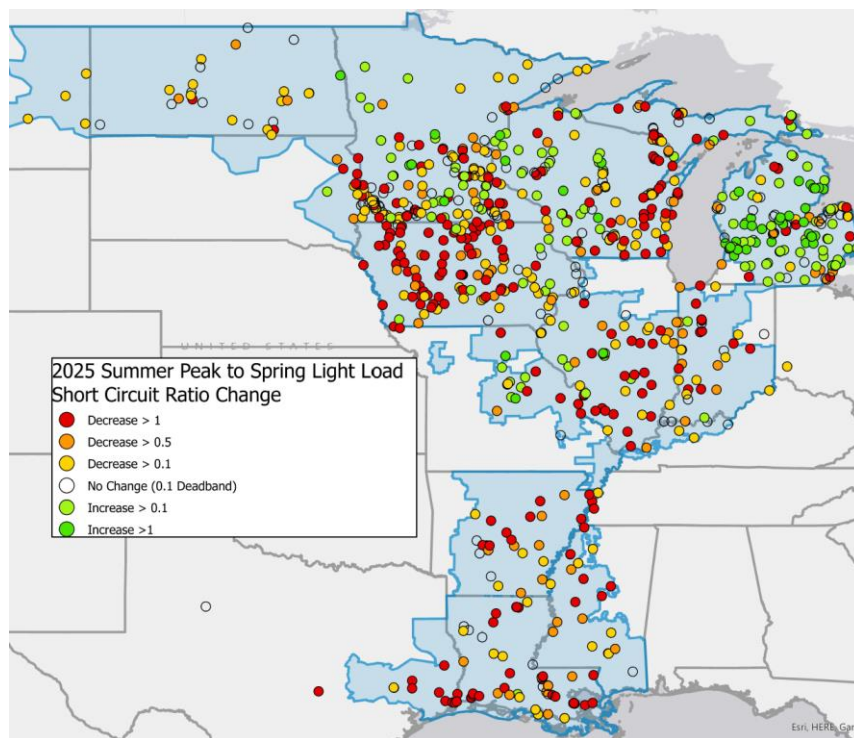


Figure 21: Change in short circuit ratio (SCR) between MTEP23 2025 summer peak and spring light load

INSIGHT: To gain greater visibility into potential voltage stability risks as the fleet transition accelerates, new scalable screening and analytics methods need to be developed

Given the localized and dynamic nature of voltage stability challenges, coupled with the granularity often required to model IBR control responses, screening accuracy at-scale becomes a significant challenge, especially for a system the size of the MISO footprint.

To illustrate this challenge, Figure 22 shows several methods for power system reliability analysis. The horizontal axis represents the study granularity or level of detail, and the vertical axis represents the level of effort, both human and computational, needed to support each tool. Increased granularity requires increased effort.

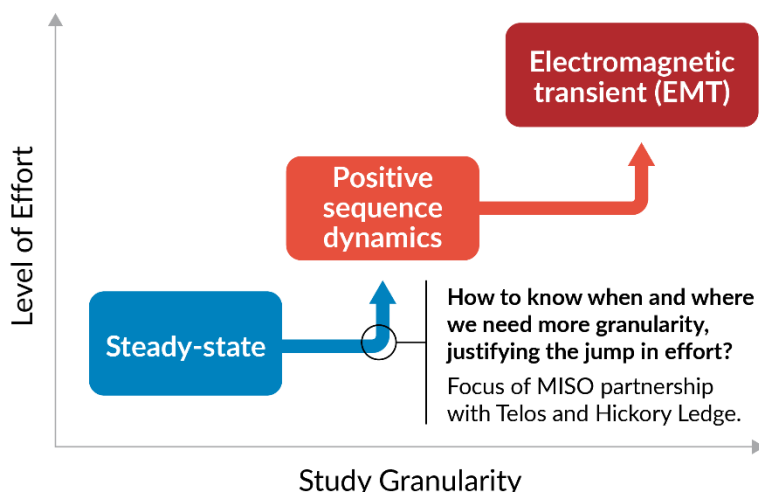


Figure 22: Illustration of effort-granularity tradeoff of common power system analysis tools

Steady state analysis is the simplest tool and can typically be performed for normal and contingency conditions at every bus location. However, steady state analysis does not provide the granularity or detail needed to understand potential dynamic voltage stability issues. A new tool is needed with practical consideration of the cost of the increased level of effort. Given the increased effort, it is typically not practical to perform more complex dynamic analysis at as many locations and under as many contingencies as the steady state analysis.

Any new approach must be scalable and accurately characterize different technology contributions to stability limits, especially given the wide range of responses from IBR's software-defined controls. In particular, the industry has recognized fundamental differences in so-called "grid-following" and "grid-forming" IBR controls.³⁵ Building on this understanding, MISO worked with energy consulting companies Telos Energy and HickoryLedge LLC to develop a repeatable analytical method to characterize these differences.³⁶ The results indicated that there are meaningful differences in the voltage support capabilities of different control types.

Figure 23 demonstrates results from the resource characterization approach using detailed electromagnetic transient (EMT) simulation on several commercially available grid-forming and grid-following inverters. The curves shown are composites from several different equipment models of that technology type and convey a typical response. Over the frequency range of interest, grid-forming controls appear to provide significant grid strengthening support capabilities, which can reduce voltage stability risks. The approach shows promise as an additional tool to characterize resources for the purpose of the simplified stability screening discussed in the next insight. Find additional details on resource characterization in section C.3.3 of the [Technical Appendix](#).

³⁵ B. Kroposki et al., "Achieving a 100% Renewable Grid: Operating Electric Power Systems with Extremely High Levels of Variable Renewable Energy," in *IEEE Power and Energy Magazine*, vol. 15, no. 2, pp. 61-73, March-April 2017.

³⁶ M. Richwine et al., "Power System Stability Analysis & Planning Using Impedance-Based Methods," in 22nd Wind & Solar Integration Workshop, September 2023, in *proceeding*.

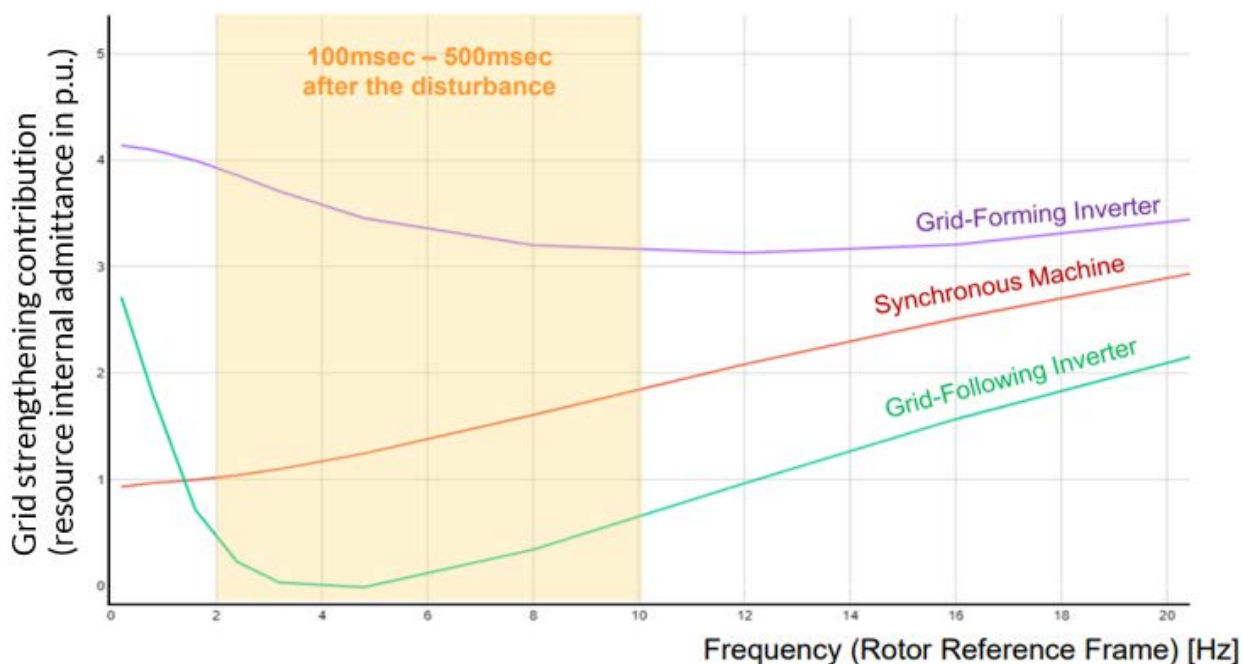


Figure 23: Resource characterization results from a series of detailed electromagnetic transient (EMT) simulations using detailed models. *Image source: Telos Energy*

INSIGHT: MISO-funded research aligns with broader industry findings showing the promise of “grid-forming” controls to support voltage stability in resource portfolios with higher levels of inverter-based resources

Recognizing potential shortcoming of existing system strength metrics and approaches, MISO worked with Telos and HickoryLedge to develop and demonstrate 1) next-generation analytical screening approaches, and 2) indicative results comparing grid-forming and grid-following inverter controls. The resulting dynamic impedance approach builds on resource characterization described in the previous insight, feeding this information into existing MISO tools to assess dynamic voltage stability limits of different resource mixes. Figure 24 provides an overview of the resource characterization and dynamic impedance screening processes.

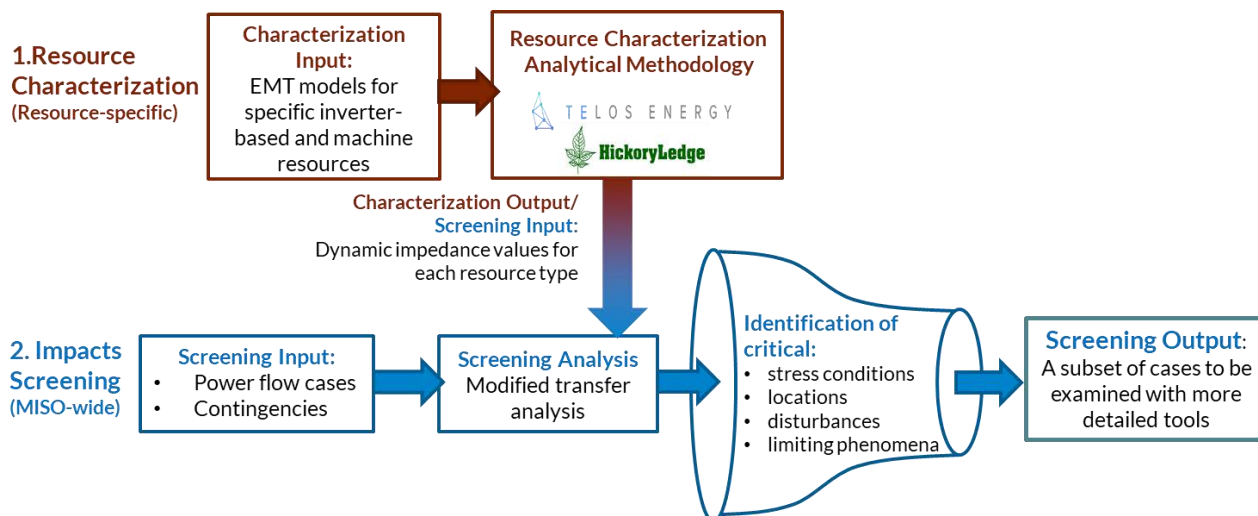


Figure 24: Overview of resource characterization and dynamic impedance screening process, described in greater detail in the [Technical Appendix](#).

The dynamic impedance screening approach was used on the scaled-up MISO system to assess the effect of resource mixes dominated by high amounts of grid-following or grid-forming inverters on dynamic voltage stability limits.³⁷ A high IBR case with high levels of grid-forming controls was shown to increase the dynamic voltage stability limit by approximately 10% when compared to a similar case that had high levels of grid-following controls. The result demonstrates a stark contrast in system strength support capabilities between grid-forming and grid-following controls and indicate grid-forming controls will be an important part of the solution to counteract risks associated with declining system strength driven by traditional resource retirements.

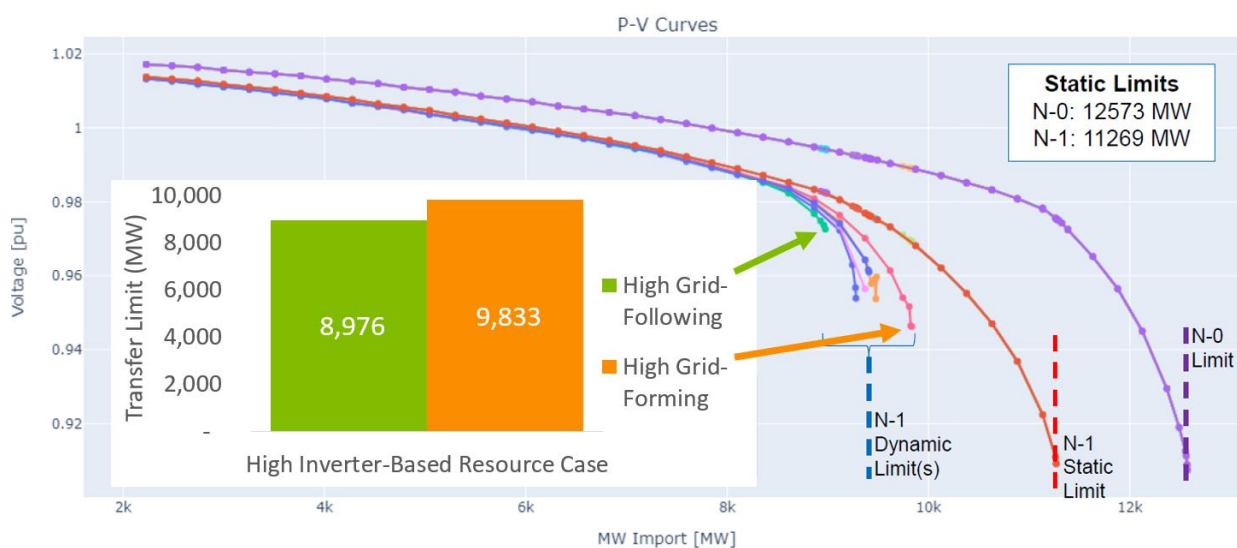


Figure 25: Dynamic impedance screening results comparing four select cases, varying IBR levels and grid-forming to grid-following proportions.

³⁷ Section C.3.3 in the [Technical Appendix](#) describes important caveats that place this demonstration assessing voltage stability limits in the realm of research and demonstration rather than conforming to typical reliability planning practices (e.g., TPL-001 contingencies).



Find a detailed explanation of the full voltage stability analysis and results in section C of the [Technical Appendix](#).

SYSTEM STABILITY ATTRIBUTE RISK IS BEST ADDRESSED THROUGH PLANNING, REGULATORY SOLUTIONS, TECHNOLOGY STANDARDS, AND LOCALIZED COST-OF-SERVICE PROCUREMENTS, WHEN APPLICABLE

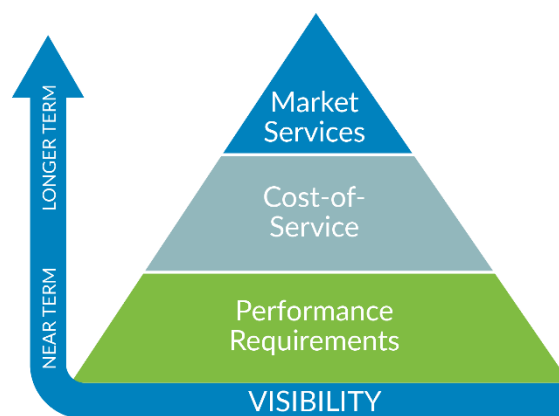
Stability challenges, including voltage stability, are best addressed in the planning timeframe by regulatory solutions because reactive deficiencies and solutions are highly localized. Obvious, low-cost solutions may be coordinated by technology standards and controls. Functionally, the types of solutions pursued should fit together in a way that drives efficiency and effectiveness, potentially forming a hierarchy (Figure 26).

Visibility: The development of new tools to provide clear visibility into localized voltage stability concerns is a prerequisite to forming any type of solution. Relatively few techniques exist for assessing large disturbance dynamic stability, and grid-following technologies appear to have a wide range of responses to more severe disturbances. Visibility examples include SCR screening, dynamic impedance screening, and critical clearing time screening.

Performance requirements: Build in voltage stability support through interconnection requirements applicable to all new resources, effectively minimizing the solution space required by other mitigations. Performance requirements should target control (i.e., software) capabilities without major cost implications. Examples include voltage ride-through, reactive current injection, and reactive power capability range.

Cost of service: Target specific needed capabilities that are outside of the standard set required for all resources. Cost of service solutions could include advanced functionalities that require additional conversion capacity or on-site energy storage.

Market services: Procure and dispatch services not met by a cost-of-service model. For instance, incentivizing the availability and delivery of stability services that an asset might otherwise withhold or not dispatch. While market services may ultimately be required in the long term, market solutions will be considered only after first exploring other options due to the localized nature of voltage stability issues.



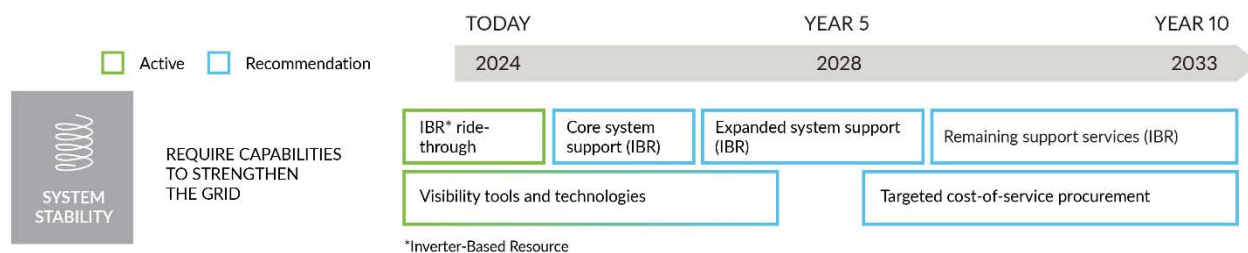
WHAT NOT TO DO NOW

Initial voltage stability issues are ineffectively addressed through market products given the local nature of the problem and solution and the subset of participants needed to engage with the issue. It has long been recognized that there cannot be a well-functioning market for reactive power like there can be for real



power; few jurisdictions have markets for reactive power services³⁸, other than incorporating voltage-based flow limits as MISO already does, and MISO is not aware of a large organized market with reactive power market products. MISO may revisit this solution in the future as these newer types of markets are demonstrated and refined on smaller island systems.

ROADMAP: REQUIRE CAPABILITIES TO STRENGTHEN THE GRID



³⁸ MISO's literature review found that Ireland's EirGrid has market services for reactive power. Further, the United Kingdom's National Grid Electric System Operator appears positioned to procure dynamic reactive power services. MISO did not view either of these island systems as directly comparable to the MISO context.



VOLTAGE STABILITY: Require capabilities to strengthen the grid
<p>Require ride-through capabilities for interconnection of inverter-based resources (IBR) to address unexpected tripping</p> <ul style="list-style-type: none"> • Adopt IBR performance from standard IEEE 2800 to keep resources online during a wider range of voltage and frequency disturbances • Address general IBR requirements (e.g., measurement accuracy, applicable voltages) to prepare for the adoption of future capabilities and performance requirements
<p>Require core system support capabilities for interconnection of IBRs to support system stability more actively</p> <ul style="list-style-type: none"> • Adopt high-level grid-forming performance requirements for energy storage systems, initially targeting “system strength” responses, with very fast resource reactive current controls • Expand adoption of IEEE 2800 to include voltage and frequency responses to support grid stability more actively under both normal and disturbance conditions. • Increase focus on assessing IBR plant conformance with sector partners
<p>Require expanded system support with more active IBR controls to support a system with high levels of IBR</p> <ul style="list-style-type: none"> • Adopt additional IBR performance requirements in IEEE 2800 which include very fast controls • Expand adoption of grid-forming performance requirements to include “synchronizing power” and “very fast frequency” (i.e., inertia-like responses) • Evaluate existing tool granularity and efficacy in assessing very fast IBR performance
<p>Require remaining support services to enable an IBR-dominant system</p> <ul style="list-style-type: none"> • Incorporate grid-forming black start capabilities so that IBR resources can qualify and contribute to re-energizing the system after major disturbances • Consider power electronic upsizing (i.e., inverter) to support system needs related to reactive fault current injection, black start, and system protection
<p>Evaluate targeted cost-of-service procurements to incentivize other technologies and the “energy buffer” required for more advanced grid-forming IBR performance</p> <ul style="list-style-type: none"> • Evaluate need for additional stability procurement requiring other technologies (e.g., static synchronous compensators, synchronous condensers, etc.) or upsized IBR hardware (e.g., inertia-like response, increased fault current) based on the impact of prior changes • Consider solution coverage over the broader range of stability issues – often categorized as voltage, frequency, angular, and converter-related – when evaluating cost of service solutions
<p>Advance visibility tools and technologies to make visible of shifting risks and support further solution evaluation</p> <ul style="list-style-type: none"> • Advance stability screening tools to better account for different types of IBR control responses • Continually refine grid-forming and grid-following model parameterization to match evolving performance requirements • Ensure appropriate model quality review procedures and tools are in place • Evaluate the need for limited electromagnetic transient (EMT) capabilities to evaluate grid-forming performance in the near-term and potentially expand to targeted system studies long-term • Consider additional needs for event recording technologies (e.g., digital fault recorders) to investigate events and validate models • Explore sensing and monitoring capabilities (e.g., phasor measurement units) for improved visibility of operational stability conditions

Table 5: Hypothesis solutions roadmap to proactively address voltage stability attribute risk by requiring capabilities to strengthen the grid.



MISO recommends IBR performance requirement adoption in four phases, each targeting specific ways in which grid-following and grid-forming IBR plants positively contribute to voltage stability. The phased design considers both reliability needs and industry readiness to install conforming plant equipment (Figure 27).

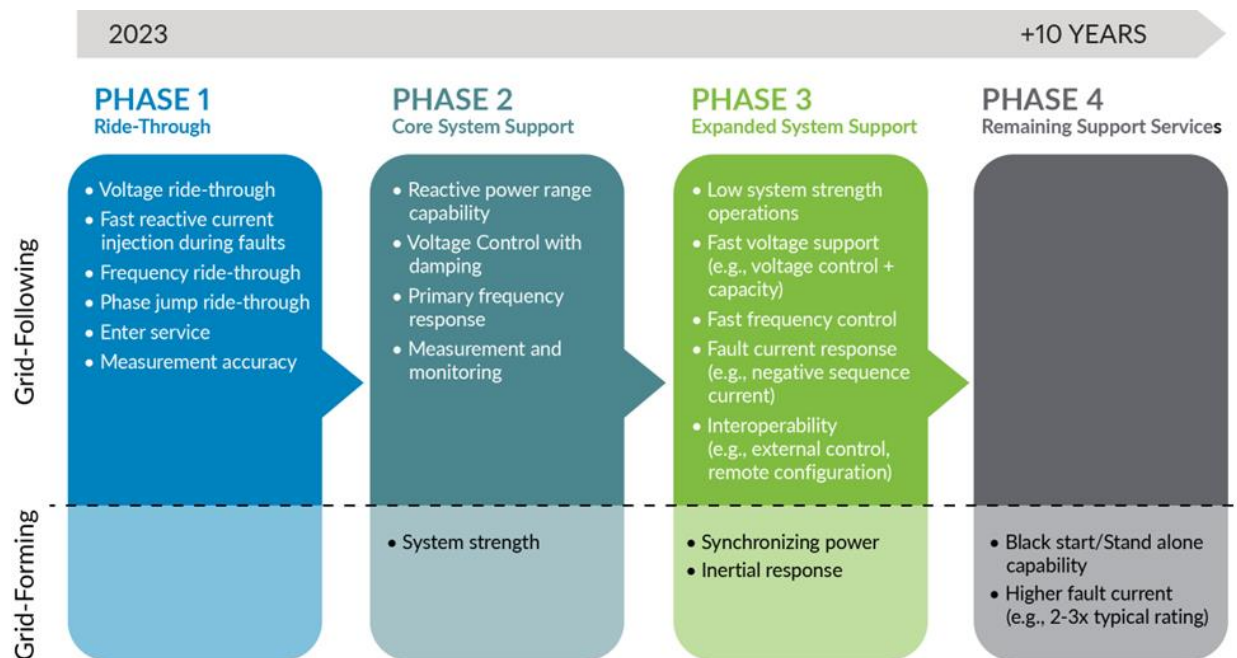


Figure 27: Summary of MISO’s phased recommendation on grid-following and grid-forming capabilities and performance requirements

SOLUTION: Require ride-through capabilities for interconnection of inverter-based resources to address unexpected tripping

In January 2023, MISO embarked on a path to improve IBR performance requirements using a reliability risk-based approach to evaluate potential gaps in MISO’s current Tariff. MISO shared the results of the risk assessment in March 2023 and finalized proposed tariff language in November 2023 to address the highest priority performance requirements and capabilities.³⁹ This proposal is Phase 1 of the recommended phased approach.

Performance requirements were prioritized based on whether they could address IBR tripping causes listed in eight recent NERC Disturbance Reports.⁴⁰ A supplemental source used for prioritization was the Federal Energy Regulatory Committee (FERC)’s IBR Notice of Proposed Rulemaking (NOPR) that led to Order 901, which in part directed NERC to develop standards to address the most significant IBR performance issues.⁴¹

The risk-based assessment found that the highest priority requirements were related to voltage support and dynamic responses. Priorities included frequency and voltage ride-through capabilities which require

³⁹ MISO, [MISO proposed GIA redlines to incorporate IBR Performance Requirements](#), Planning Advisory Meeting Materials, November 15, 2023.

⁴⁰ NERC, [Event Reports](#), accessed November 2023.

⁴¹ FERC, [Docket No. RM22-12-000](#); Order No 901. Issued October 19, 2023.



IBRs to stay connected during a range of disturbances, expanding on existing MISO ride-through requirements. Other priorities marked new capabilities, such as rate-of-change-of frequency ride-through and transient over-voltage ride-through, not contemplated in existing MISO requirements. Beyond ride-through, other capabilities identified as high priority for maintaining reliability include current injection during voltage ride-through and enter service criteria.

SOLUTION: Require core system support capabilities for interconnection of inverter-based resources to more actively support system stability

For Phase 2, MISO recommends developing grid-forming performance requirements for Battery Energy Storage Systems (BESS), targeting finalization of the performance capabilities by early 2025 with implementation timing determined with input from stakeholders. The grid-forming BESS requirements in Phase 2 aim to address strength support (i.e., fast reactive power support for voltage changes).

A NERC whitepaper released in September 2023 recommends that all newly interconnecting BESS should have grid-forming controls.⁴² NERC also states that grid-forming requirements, testing procedures, policies, and/or incentives should be developed now for BESS and co-located resources with BESS. NERC suggests grid-forming BESS technology offers a low-cost opportunity to improve stability. MISO agrees with these recommendations and suggests phasing in grid-forming requirements through MISO's stakeholder processes.

Regarding grid-following performance, MISO recommends expanding adoption of the IEEE 2800-2022⁴³ standard to include additional voltage and frequency capabilities and performance specifications to support grid stability more actively during normal operations (steady state) and disturbances (dynamic). These requirements could include reactive power range capabilities and voltage control with damping performance to support small signal voltage stability (e.g., sub-synchronous oscillations). In addition, MISO may recommend other performance not directly related to voltage stability, such as primary frequency response. Given the more active nature of some of these responses, additional supporting analysis is likely required, and MISO may consider recommending IEEE 2800 clauses related to measurement and monitoring to support performance monitoring and model validation.

Emerging grid-forming practices around the globe – *International grid operators overseeing resource transitions to high penetrations of IBRs have begun encouraging or requiring grid-forming capabilities from new resource interconnections. The Australian Energy Market Operator¹ and National Grid Electricity System Operator (NGESO)¹ have published voluntary grid-forming specifications, which are seen as a first step to contributing to stability support. Finland's Fingrid has released mandatory grid-forming specification that apply to only battery energy storage system (BESS) projects interconnecting in weak grid areas.¹ These early specifications focus on what some call "core" grid-forming capabilities, which are well-known capabilities that require no or minimal material modification to inverters compared to current grid-following practices.*

⁴² NERC. "[White Paper: Grid Forming Functional Specifications for BPS-Connected Battery Energy Storage Systems](#)", September 2023.

⁴³ IEEE, "[IEEE Standard for Interconnection and Interoperability of Inverter-Based Resources \(IBRs\) Interconnecting with Associated Transmission Electric Power Systems](#)", April 2022.



As IBR performance requirements continue to mature in the U.S., MISO recommends increased focus on assessing IBR plant conformance together with sector partners (interconnection customers, transmission owners, generator owners) and aided by international practices. MISO anticipates the future publication of draft standard IEEE P2800.2⁴⁴ will aid in defining conformance assessment best practices. Until then, MISO recommends working with the stakeholder community to define stopgap measures to ensure efficacy of performance requirements in place.

SOLUTION: Require expanded inverter-based resource performance to support a system with high levels of IBR

In Phase 3, the expanded system support performance requirement recommendations include adoption of remaining IEEE 2800 capabilities and performance; extending grid-following inverter requirements beyond current standards; and introducing additional grid-forming performance requirements for battery storage (BESS). These requirements start to extend stability support performance beyond strictly targeting voltage stability, which MISO recommends as additional attribute risk factors come into focus (e.g., declining system inertia).

Assuming no revision of IEEE 2800, additional performance capabilities recommended for adoption include fast frequency response, fault current response (e.g., negative sequence current), and expanded interoperability features (e.g., remote configuration). These expanded system support requirements come with more decision points and the potential for expanded analysis needs when compared to the earlier groupings of performance requirements. For instance, while IEEE 2800 offers different approaches for fast frequency response⁴⁵, industry research is still evaluating the use cases and effectiveness of these different options.⁴⁶ Considering additional grid-following capabilities, MISO will also consider recommendations that are not currently contemplated in IEEE 2800, such as defining a minimum level of system strength at which grid-following controls must be capable of stable operations.

Building upon grid-forming BESS recommendations established, MISO will expand performance requirements for this technology in Phase 3 to include expanded stability support features such as synchronizing power and very fast frequency response (i.e., inertia-like response). MISO anticipates additional detailed analysis will be required before enabling very fast frequency control to prevent unintended control interactions.

Lastly, MISO will assess industry readiness to expand grid-forming requirements to other IBR such as wind and solar resources without a storage component. MISO understands original equipment manufacturers are developing grid-forming capabilities for wind and solar plant equipment but have not publicly committed to timeframes when equipment may be available. MISO will continue to monitor industry control developments.⁴⁷

⁴⁴ IEEE. (Draft) [Recommended Practice for Test and Verification Procedures for Inverter-Based Resources \(IBRs\) Interconnecting with Bulk Power Systems](#).

⁴⁵ IEEE 2800-2022 includes discussion on fast frequency response (FFR) proportional to frequency deviation, FFR proportional to the rate of change of frequency (df/dt), fixed magnitude FFR with frequency trigger (step response), fixed magnitude FFR with df/dt trigger.

⁴⁶ NREL, [Different Types of Fast Frequency Response from Inverter Based Resources](#), October 2023.

⁴⁷ MISO participates in the universal interoperability for grid-forming inverters (UNIFI) consortium and NERC's inverter-based resource performance subcommittee (IRPS), among other industry venues. UNIFI, [Specification for Grid-forming Inverter-Based Resources, Version 1, December 2022](#). NERC, [Inverter-Based Resource Performance Subcommittee \(IRPS\)](#).



SOLUTION: Require remaining support services to enable an inverter-based-resource-dominant system

Preparing for a system with very high levels of load served by IBR, MISO's Phase 4 recommends incentivizing capabilities for remaining services that are primarily supplied by synchronous machines today. This largely translates to targeting black start and fault current needs which carry additional costs requiring incentivization.

MISO recommends defining grid-forming black start capabilities and performance requirements so that IBRs can qualify and contribute to re-energizing the system after major disturbances. Stakeholders and MISO may need to investigate potential barriers to IBR qualification as black start resources and consider options to allow resources with needed capabilities to participate.

Further, MISO recommends exploring inverter upsizing requirements needed for system support services related to reactive fault current injection, black start, and system protection (i.e., fault detection). Upsizing equipment drives increased capital costs, and potential operating and maintenance expenses, which would likely require incentives. Potential incentives are discussed further in the conditional solution section that follows.

SOLUTION: Evaluate targeted cost-of-service procurements to incentivize other technologies and the “energy buffer” required for more advanced grid-forming inverter-based resource performance

MISO anticipates that low-cost performance requirements, largely implementable through software-defined control changes, will provide only partial coverage of steady state and dynamic voltage stability needs. Additional assets are likely needed to address steady state reactive power and voltage damping requirements as well as fast active and reactive current responses.

A range of technologies are available to address voltage stability needs, including capacitor banks, static var compensators, static synchronous compensators (STATCOM), enhanced STATCOMs (i.e., on-board storage), high-voltage direct current (HVDC) terminals, and synchronous condensers. Each technology has unique technical and economic considerations. MISO recommends assessing applicable technology characteristics to gauge the potential role of each technology to mitigate stability risks and determine which assumptions to use in planning studies, should the technology be proposed as a potential mitigation measure. MISO may consider additional analysis to demonstrate potential roles for each technology. Such analysis should be coordinated with additional stability considerations (e.g., frequency, angular, converter-related). This was out of scope for this year's attributes effort.

Another cost-of-service mechanism may be required for IBR performance requirements that materially impact the capital or operating and maintenance costs for IBR plants. MISO suggests these additional costs are likely to materialize to address (1) IBR converter upsizing, and (2) “energy buffers.”

Converter upsizing allows for higher instantaneous current injection which could be needed to support higher levels of steady state reactive power, reactive fault current injection, black start capabilities, and system protection needs (i.e., fault detection). The level of converter upsizing to support voltage stability would be based on site-specific assessments of system needs. Future long-range assessments could consider evaluating indicative magnitudes and potential locations of converter upsizing opportunities.



Energy buffers ensure active power can be supplied when needed, which can come in the form of storage or operating a plant below the maximum available power. Energy buffer requirements may require additional equipment, such as batteries or super capacitors, or missed opportunity costs for selling energy or providing ancillary services. Examples of services that may require an energy buffer could include synchronizing power and frequency responses.

SOLUTION: Advance visibility tools and technologies to improve transparency of shifting risks and support further solution evaluation

Building upon the 2023 work, MISO and stakeholders should consider options to advance stability screening tools to better account for different types of IBR control responses. MISO recommends continued development and evaluation of the dynamic impedance screening approach. In addition, other approaches beyond SCR (e.g., critical clearing time metrics adapted for IBR) should be considered. The objective is to have scalable approaches to accurately assess the various stability challenges that could emerge in a high IBR resource portfolio.

Future approaches should continue to refine selection of analysis tools (e.g., positive sequence dynamics versus electromagnetic transient) and IBR model parameterization to match evolving performance requirements and impact assessment needs. Recent NERC event reports have indicated that there are reliability risks associated with inaccurate models and insufficient tool granularity.⁴⁸ MISO recommends engaging stakeholders to ensure appropriate model quality review procedures and tools are in place within the generator interconnection process.

MISO also recommends investigating the need for limited EMT simulation capabilities to evaluate grid-forming functional performance in the near term and potentially expanding to targeted system studies in the future. EMT capabilities are also needed for resource characterization within the dynamic impedance screening approach. NERC and industry have recognized the need for model quality verification procedures, especially when using EMT models. MISO recommends working with stakeholders to explore the need for standardized model quality review procedures, both for positive sequence dynamics models and EMT models, to the extent each type of model is required.

Lastly, MISO recommends investigating the need for operational sensing and monitoring technologies to improve visibility in the operating horizon and for use in post-event investigations. As an example, MISO recommends working with stakeholders to consider additional needs for event recording technologies (e.g., digital fault recorders) to investigate events and validate models. Further, MISO and stakeholders should explore sensing and monitoring capabilities (e.g., phasor measurement units) for improved visibility of operational stability conditions across a wide area.

SYSTEM STABILITY ANALYSIS NEXT STEPS

Future investigations into voltage stability risks and solutions could target questions such as:

- What proportion of new IBR should be grid-forming, and at what locations, to support reliability and reduce overall system costs?

⁴⁸ NERC, [2022 Odessa Disturbance](#), December 2022.



- What mix of other technologies (BESS, enhanced STATCOM, synchronous condensers, etc.) best supplements advanced IBR controls for stability support?
- How much energy buffer is needed for certain grid-forming capabilities (e.g., synchronizing power)?
- How much converter upsizing is needed to meet stability or system protection needs?
- How do different types of loads (e.g., high vs low inertia loads) effect the performance of grid-forming, grid-following, and different combinations of these controls?

Acknowledgments

MISO thanks The Brattle Group, Telos Energy, and HickoryLedge LLC for their contributions to this effort.

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The latest status of MISO’s attributes-related work can be found on MISO’s Dashboard for “[Identification of Sufficient Reliability Attributes RASC – 2022-1](#).” Ongoing stakeholder discussions will be coordinated through the MISO Stakeholder [Resource Adequacy Subcommittee](#).



Acronyms

<i>AEMO: Australian Energy Market Operator</i>	<i>LMR: Load Modifying Resource</i>
<i>BESS: Battery Energy Storage System</i>	<i>LOLE: Loss of Load Expectation</i>
<i>CCGT: combined-cycle gas turbine⁵¹</i>	<i>LOLH: Loss of Load Hours</i>
<i>CVaR: Conditional Value at Risk</i>	<i>MISO: Midcontinent Independent System Operator</i>
<i>DER: Distributed Energy Resource</i>	<i>MTEP: MISO Transmission Expansion Plan</i>
<i>DLOL: Direct Loss of Load</i>	<i>NERC: North American Reliability Corporation</i>
<i>EGRET: Electric Grid Research & Engineering Tool</i>	<i>NOPR: Notice of Proposed Rulemaking</i>
<i>EMS: Energy Management System</i>	<i>NSI: Net Scheduled Interchange</i>
<i>EMT: Electromagnetic Transient</i>	<i>PRA: Planning Resource Auction</i>
<i>EPRI: Electric Power Research Institute</i>	<i>PRM: Planning Reserve Margin</i>
<i>EUE: Expected Unserved Energy</i>	<i>PRMR: Planning Reserve Margin Requirement</i>
<i>FERC: Federal Energy Regulatory Commission</i>	<i>RAN: Resource Availability and Need</i>
<i>GFL: Grid Following</i>	<i>RBDC: Reliability-based demand curve</i>
<i>GFM: Grid Forming</i>	<i>RDT: Regional Directional Transfer</i>
<i>HVDC: High Voltage Direct Current</i>	<i>RIIA: Renewable Integration Impact Assessment</i>
<i>IBR: Inverter-Based Resource</i>	<i>RRA: Regional Resource Assessment</i>
<i>IEEE: Institute of Electrical and Electronics Engineers</i>	<i>RTO: Regional Transmission Organization</i>
<i>IMM: Independent Market Monitor</i>	<i>SCR: Short Circuit Ratio</i>
<i>LAC: Look-Ahead Commitment</i>	<i>STATCOM: Static Var Compensators, Static Synchronous Compensators</i>

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Attachment V

MISO's Response to the Reliability Imperative, MISO
(Updated Feb. 2024)



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



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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>
<p>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</p>	<ul style="list-style-type: none"> • Ensure resources are accurately accredited • Identify critical system reliability attributes • Ensure accurate pricing of energy & reserves
<p>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</p>	<ul style="list-style-type: none"> • 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
<p>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</p>	<ul style="list-style-type: none"> • 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
<p>SYSTEM ENHANCEMENTS Create flexible, upgradeable and secure systems that integrate advanced technologies to process increasingly complex information and evolve with the industry</p>	<ul style="list-style-type: none"> • 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.



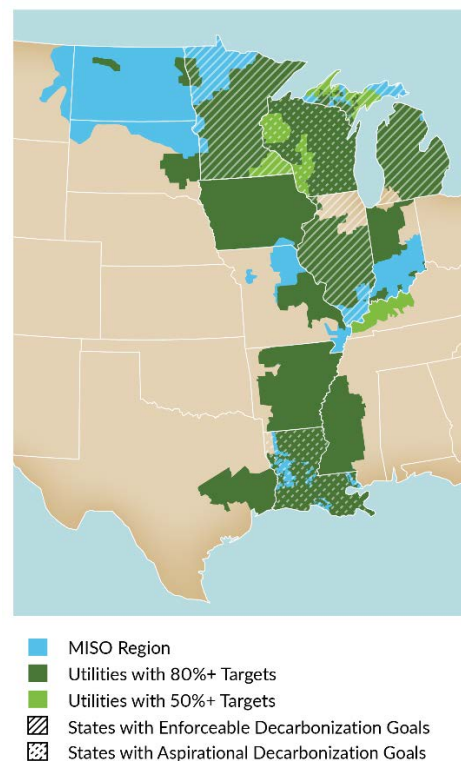
Challenges Driving the Reliability Imperative

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.



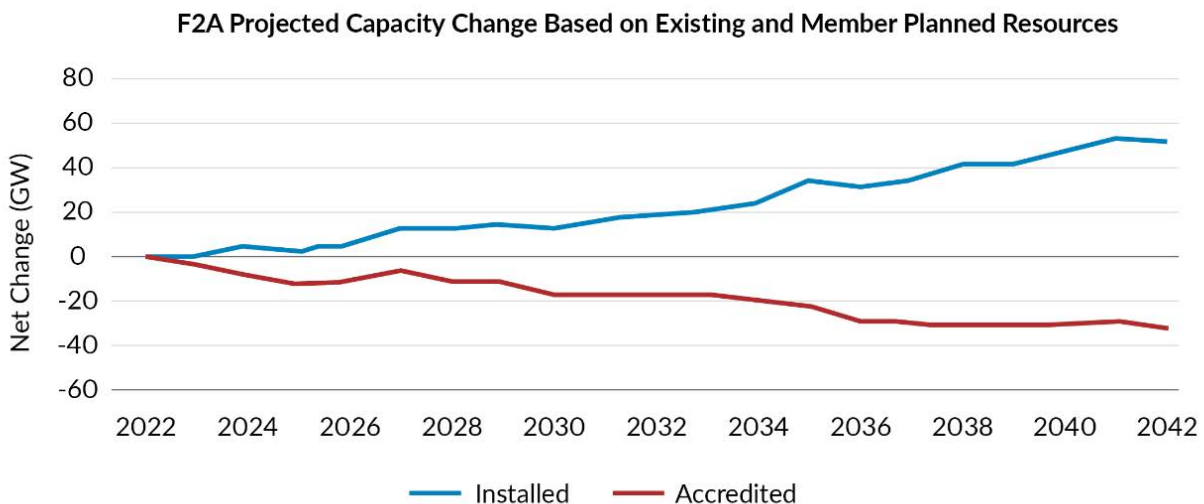
An annual planning tool called the **OMS-MISO Survey** tells a similar story. The survey compiles information about new resources utilities and states plan to build and older assets they intend to retire in the coming years. [The 2023 survey](#) shows the region’s level of “committed” resources declining 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 –



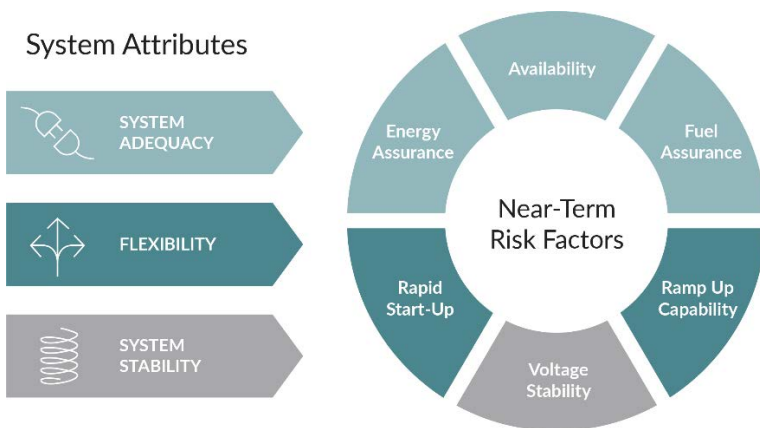
primarily wind and solar — that utilities and states plan to build in that 20-year time period.¹ But because those new wind and solar resources have significantly lower accreditation values² than the conventional resources that utilities and states plan to retire in the same 20-year period, the region’s 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

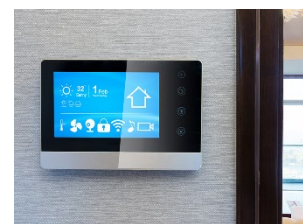
Some parts of the MISO region are enjoying a resurgence in manufacturing and/or other economic growth, with companies planning and building new factories, data centers and other energy-intensive facilities. For example, in the MISO South subregion that spans most of Arkansas, Louisiana, Mississippi and 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.

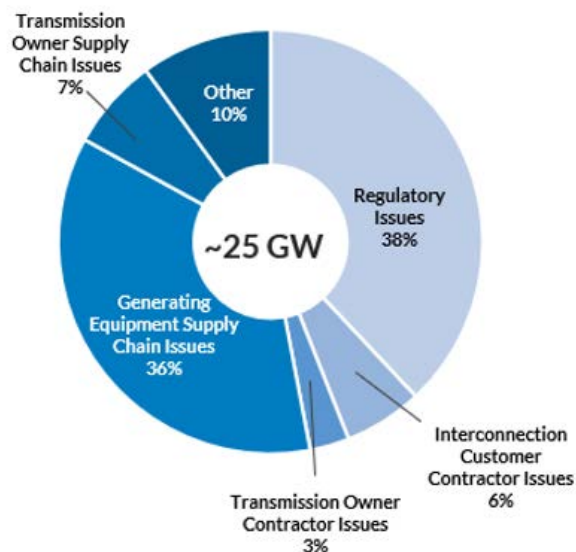
FUEL ASSURANCE RISKS

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



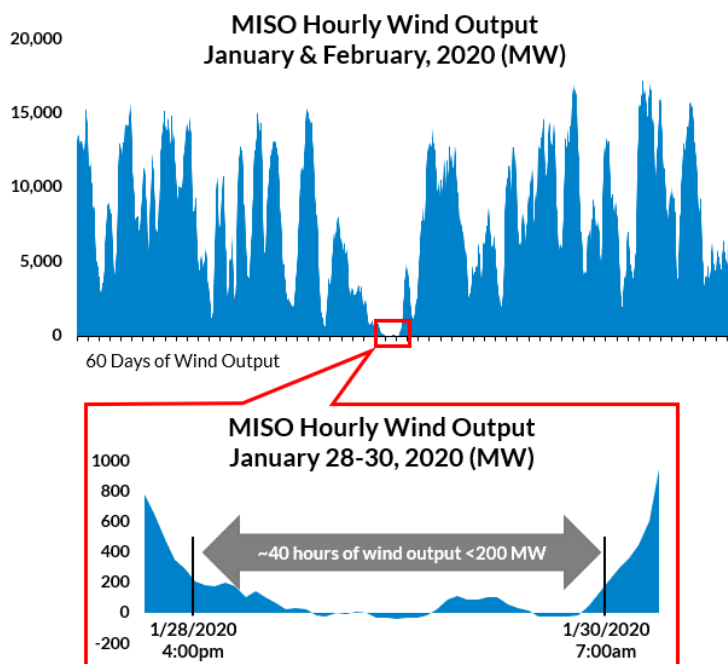


contracts, opting instead for less costly “interruptible” pipeline service or a blend thereof. Only about 27% of the gas generation that responded to MISO’s [2023-2024 Generator Winterization Survey](#) indicated it had firm transport contracts in place for all of their supplies during the 2023-2024 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 w 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

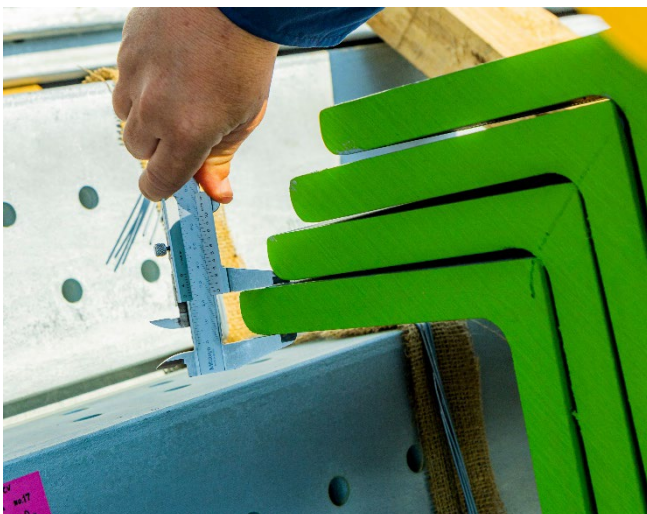


intends to implement going forward. MISO is reviewing the order to assess potential changes and compliance needs.

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.

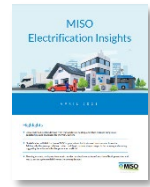


Markets of the Future: This report illustrates how and when MISO's market structures will need to evolve in order to accommodate the transformation of the energy sector. The needs are presented in four broad categories: (1) Uncertainty and Variability, (2) Resource Models and Capabilities, (3) Location 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

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Attachment W

**2025 OMS-MISO Survey Results, OMS and MISO
(Updated June 6, 2025)**



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.

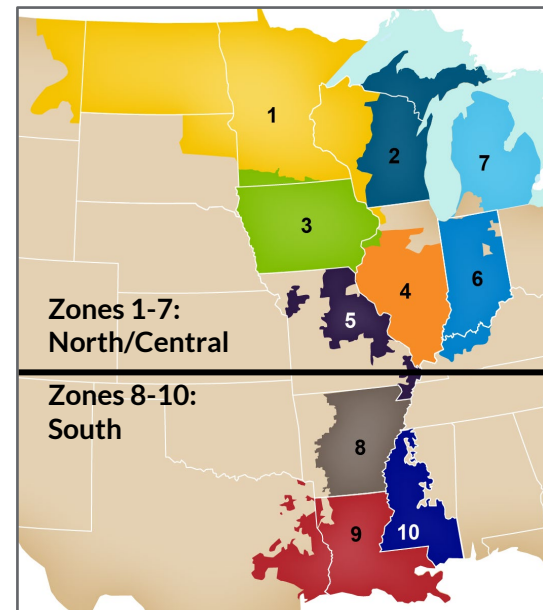
All references to capacity in this presentation indicate seasonal accredited capacity (SAC), unless noted otherwise.

**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	<ul style="list-style-type: none"> No Changes 	<ul style="list-style-type: none"> 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	<ul style="list-style-type: none"> Historical Projection: Results in 3.5 GW/yr <ul style="list-style-type: none"> <i>Driven by 2022-2024 actuals</i> Emerging Projection: Results in 6.2 GW/yr average <ul style="list-style-type: none"> <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> 	<ul style="list-style-type: none"> 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	<ul style="list-style-type: none"> Replacement Impact Highlighted: Results in additional “new resources” to offset the impacts of retirements Historical Replacement : Valued at 1.2 GW/yr <ul style="list-style-type: none"> <i>50% replacement & surplus queue adoption</i> Emerging Replacement: Valued at 2.4 GW/yr <ul style="list-style-type: none"> <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> 	<ul style="list-style-type: none"> Not included
 Committed Capacity	<ul style="list-style-type: none"> No Changes 	<ul style="list-style-type: none"> Existing generation resources External resources with firm contracts to MISO load Assumes resources will be used to meet PRMR

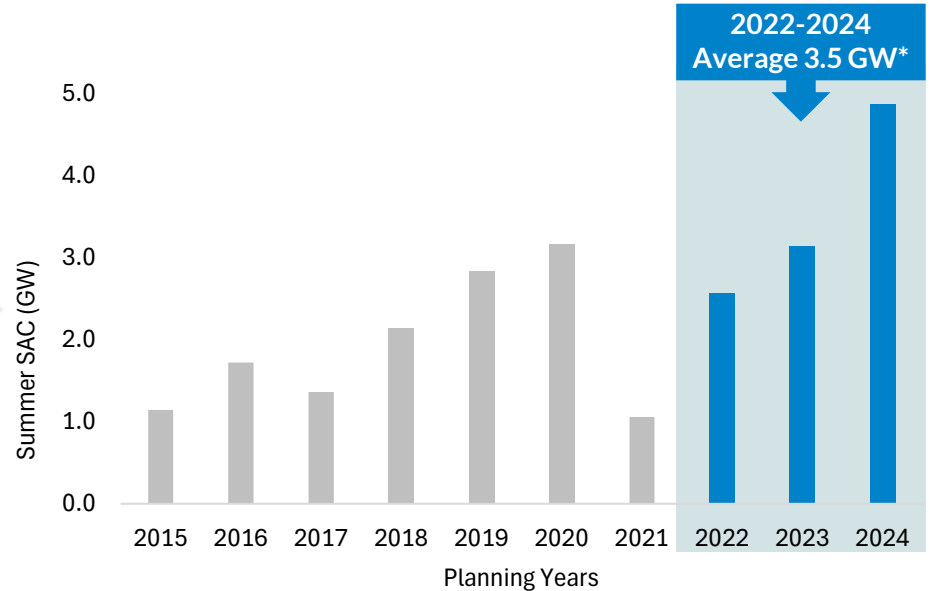
Trends and market pressures related to new capacity additions suggest that refinements are needed to better reflect uncertainty

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

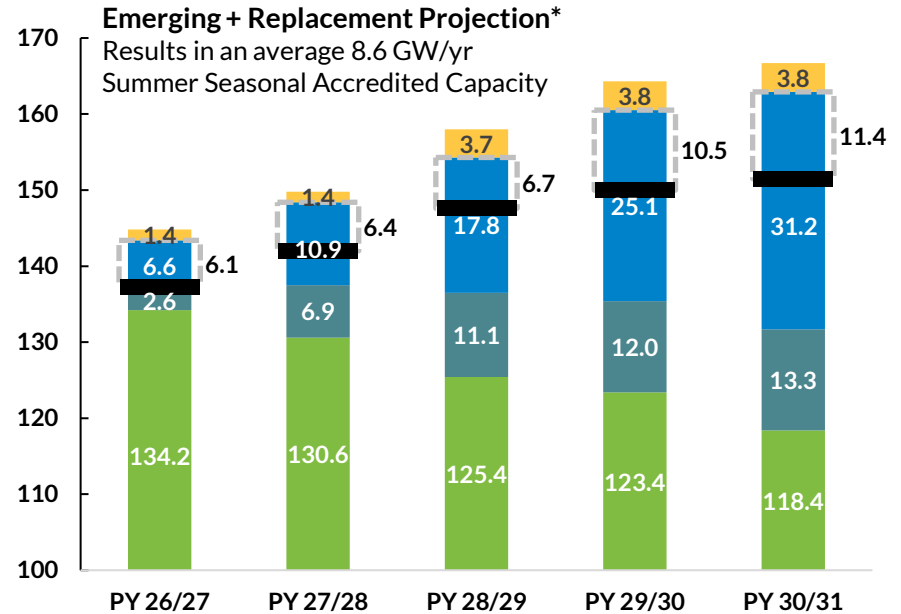
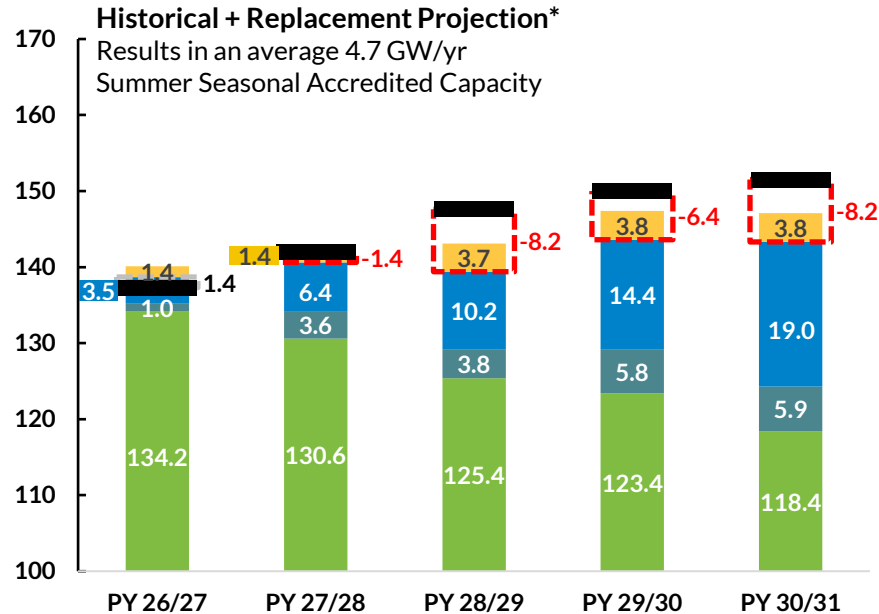


Queue applications: Nameplate 296 GW Queue & 54 GW Signed GIAs not yet online (as of 5/14/25)

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	<ul style="list-style-type: none"> No Changes 	<ul style="list-style-type: none"> 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	<ul style="list-style-type: none"> Historical Projection: Results in 1.4 GW/yr <ul style="list-style-type: none"> <i>Driven by 2022-2024 actuals</i> Emerging Projection: Results in 4.1 GW/yr average <ul style="list-style-type: none"> <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> 	<ul style="list-style-type: none"> Not included
 Replacement/ Surplus Project Impact Potential New Capacity – Existing Point of Interconnection	<ul style="list-style-type: none"> Replacement Impact Highlighted: Results in additional “new resources” to offset the impacts of retirements Historical Replacement : Valued at 1.0 GW/yr <ul style="list-style-type: none"> <i>50% replacement & surplus queue adoption</i> Emerging Replacement : Valued at 2.1 GW/yr <ul style="list-style-type: none"> <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> 	<ul style="list-style-type: none"> Not included
 Committed Capacity	<ul style="list-style-type: none"> No Changes 	<ul style="list-style-type: none"> Existing generation resources External resources with firm contracts to MISO load Assumes resources will be used to meet PRMR

PRMR: Planning Reserve Margin Requirement

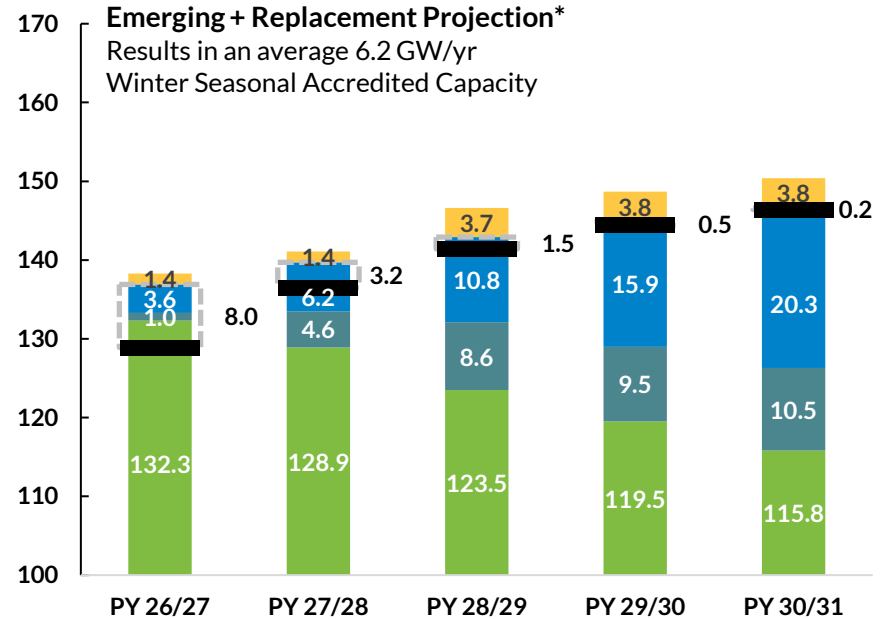
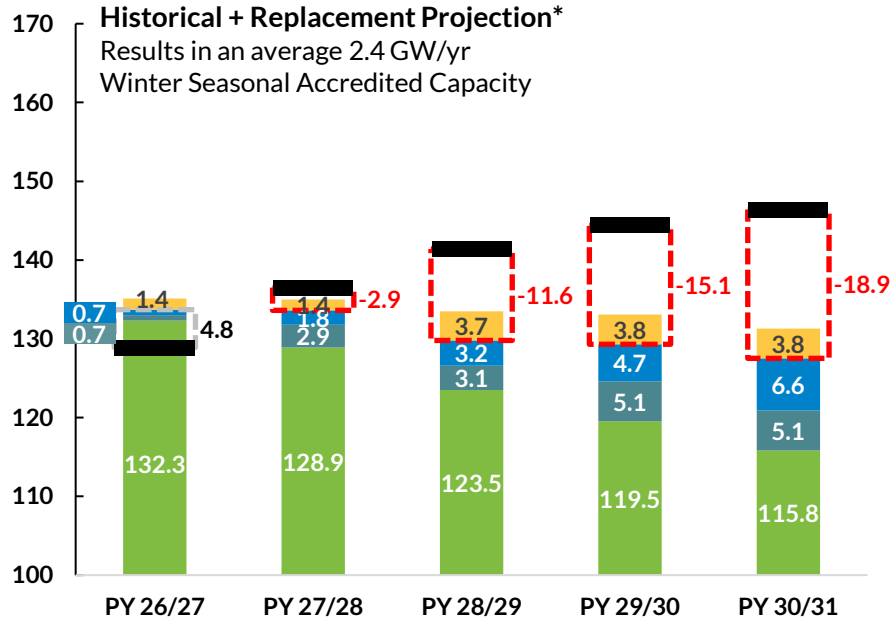
Committed Capacity: Resources committed to serving MISO’s load

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

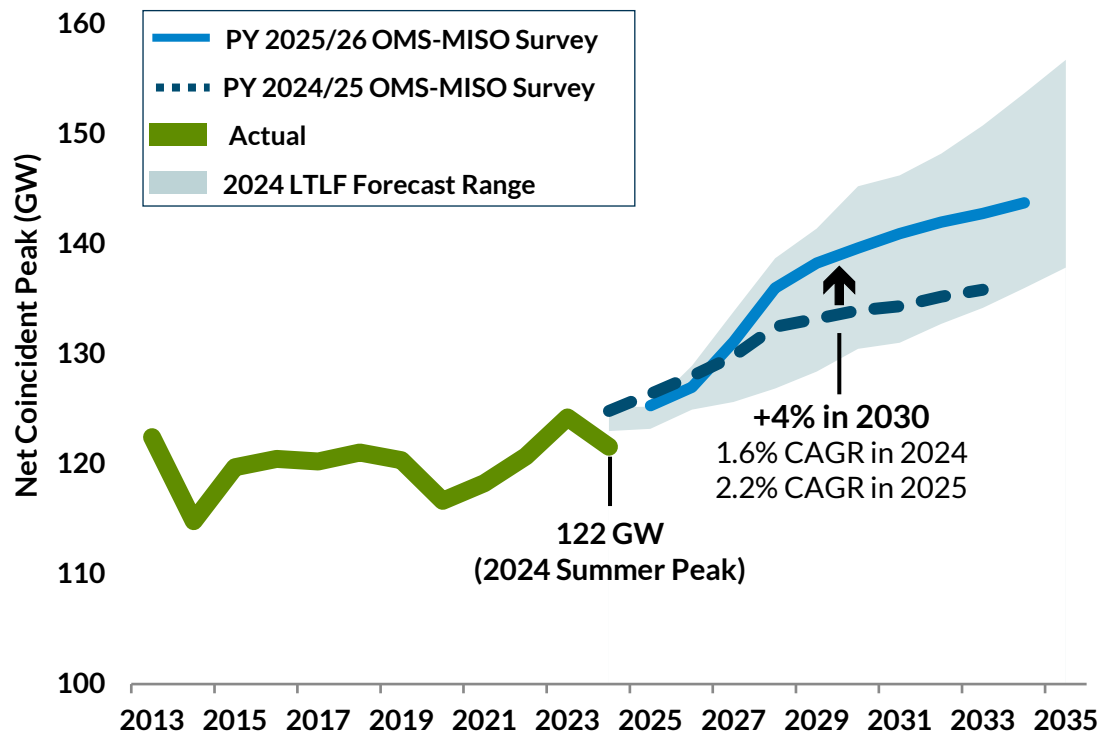
*Using methods for potential New Capacity described on Slide 8
PRMR: Planning Reserve Margin Requirement

- 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



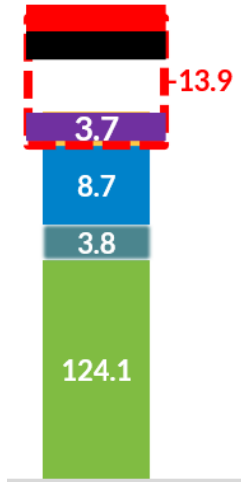
- Load growth through 2035 will exacerbate capacity shortfall and operational risks
- Many new loads will require additional firm, controllable resources

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



- Data Centers (149-241)
- Electric Vehicles (54-91)
- Industry Development & Offshoring (21-105)
- Hydrogen (25-95)
- 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

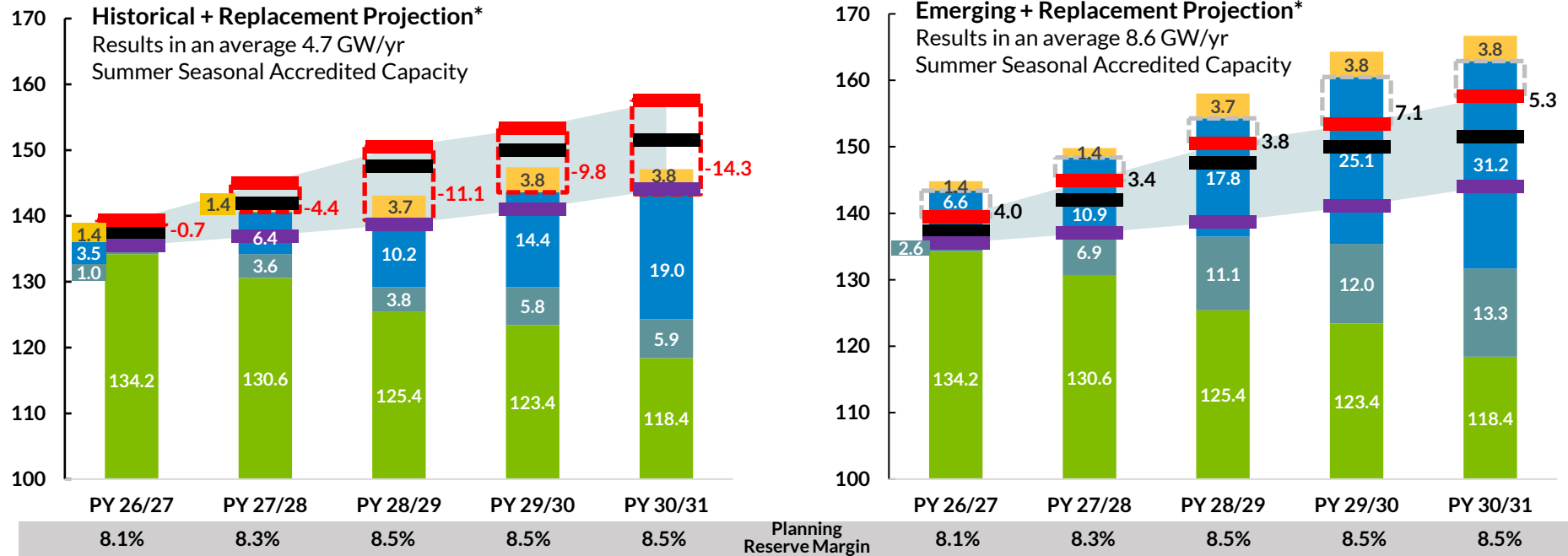
- LSE-submitted Non-Coincident Peak Forecast (NCPF) converted to Coincident Peak Forecast (CPF) using MISO-posted coincidence factors
- Transmission losses added
- PRMR calculated using out year PRM% from PY 2025/26 LOLE Study

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

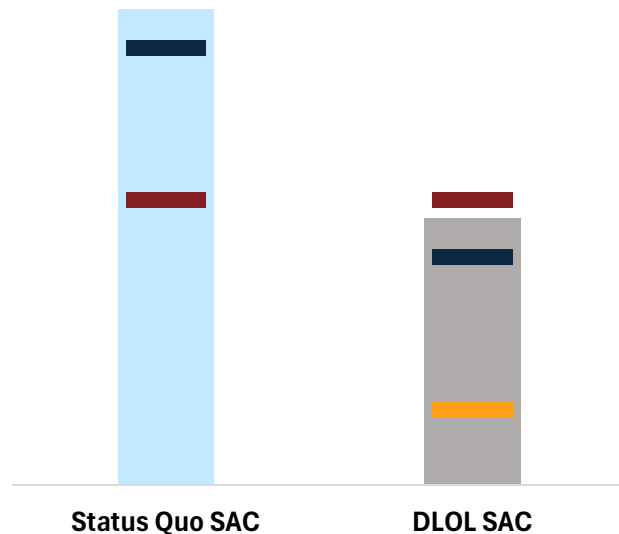
MISO's existing accreditation methods can overstate a resource's capacity value during the highest risk periods, especially as the region's risk profile changes, leading to understated risk

- 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

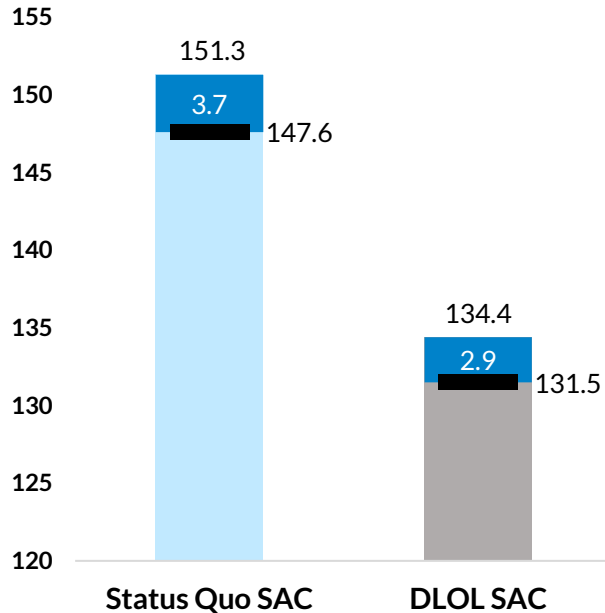
- Status Quo: Peak Load
- DLOL: critical hours

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

Grey: DLOL SAC value of Resources during critical hours to meet PRMR

Status Quo vs Direct Loss of Load Accreditation for summer 2028

Comparing Accreditation from Status Quo & DLOL Seasonal Accredited Capacity Summer 2028 (GW)



- 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

- Planning Reserve Margin Requirement (PRMR)
- Surplus (Nearly equivalent between Status Quo & DLOL)
- Status Quo SAC value of Resources during MISO peak to meet PRMR
- DLOL SAC value of Resources during critical hours to meet PRMR

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

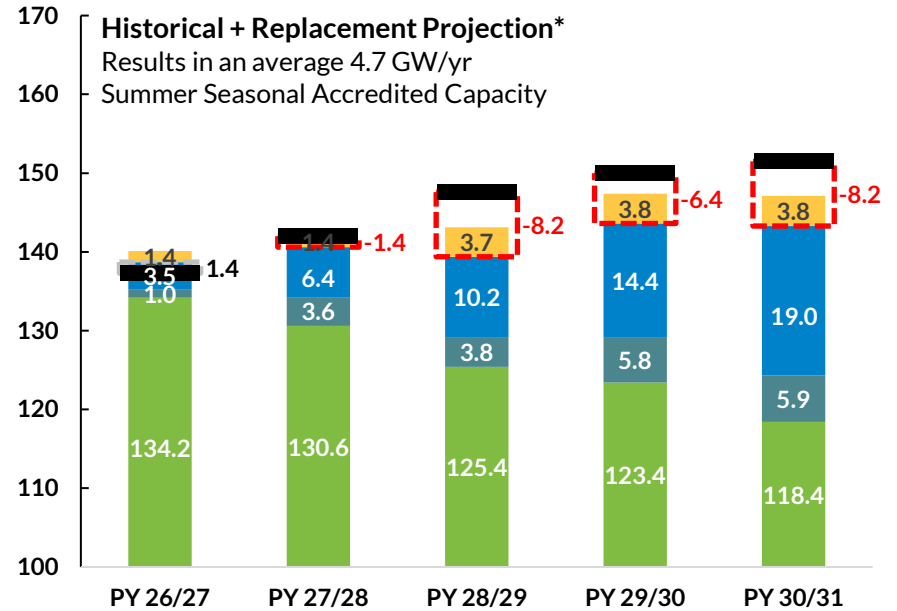
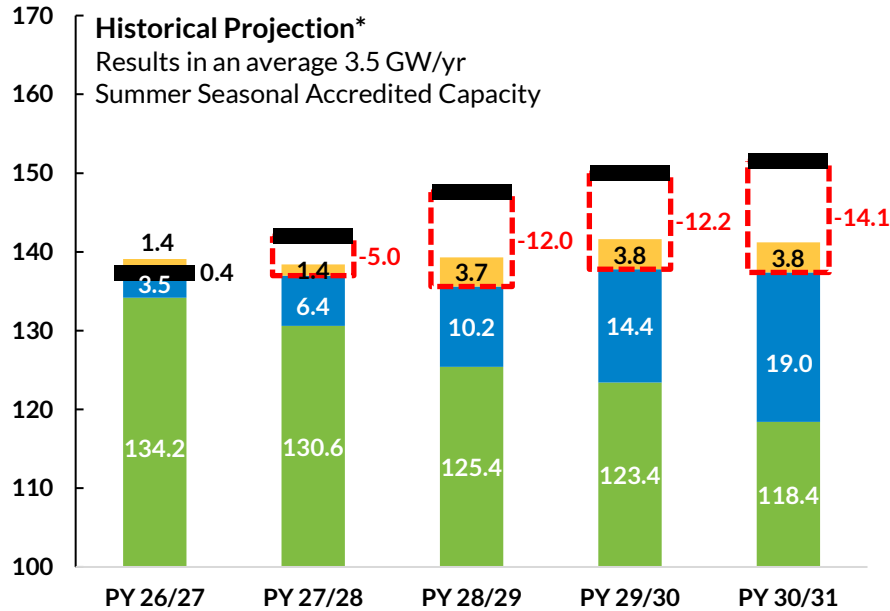
- This year's survey highlights significant uncertainty in projected resource adequacy, underscoring the urgent need for accelerated resource additions, strategic retirement planning, and proactive management of increasing load growth.
- Ongoing collaboration between OMS and MISO remains essential to 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

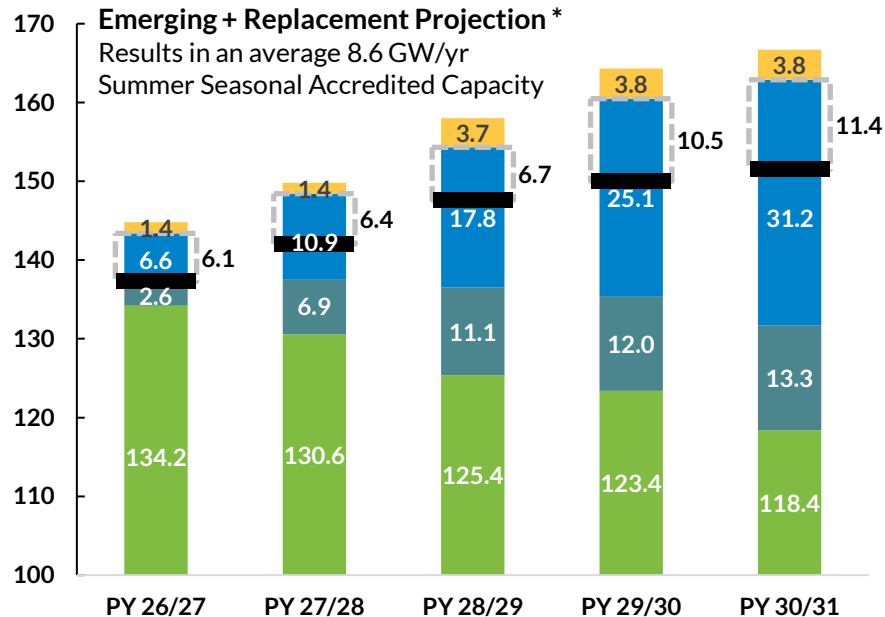
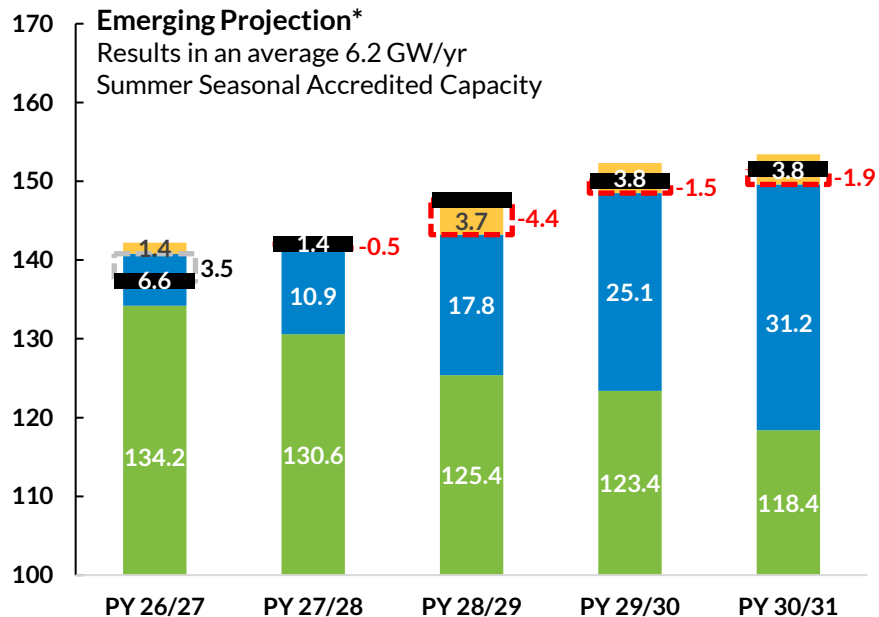
- Red border values indicate the additional potential deficit against the Projected PRMR
- Gray border values indicate the potential surplus against the Projected PRMR

- 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

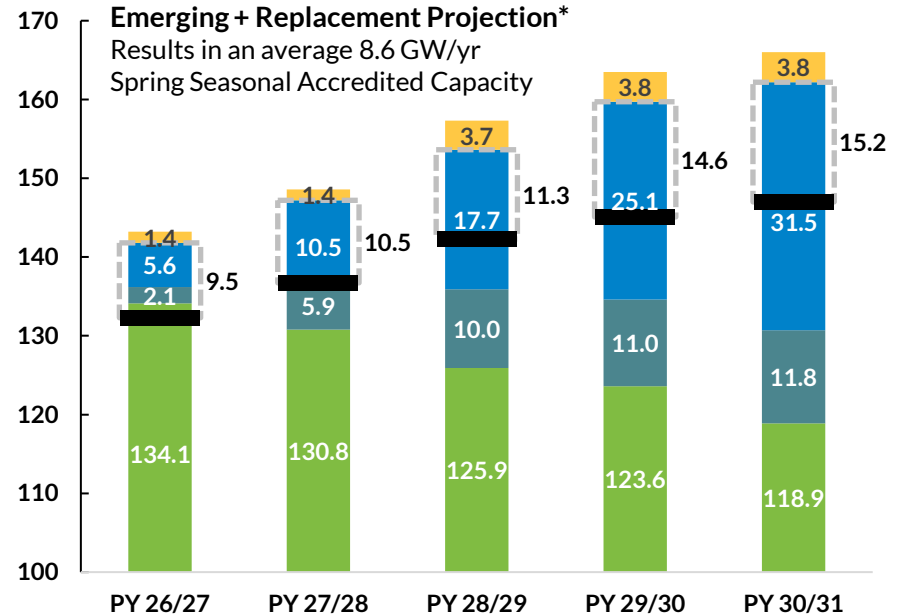
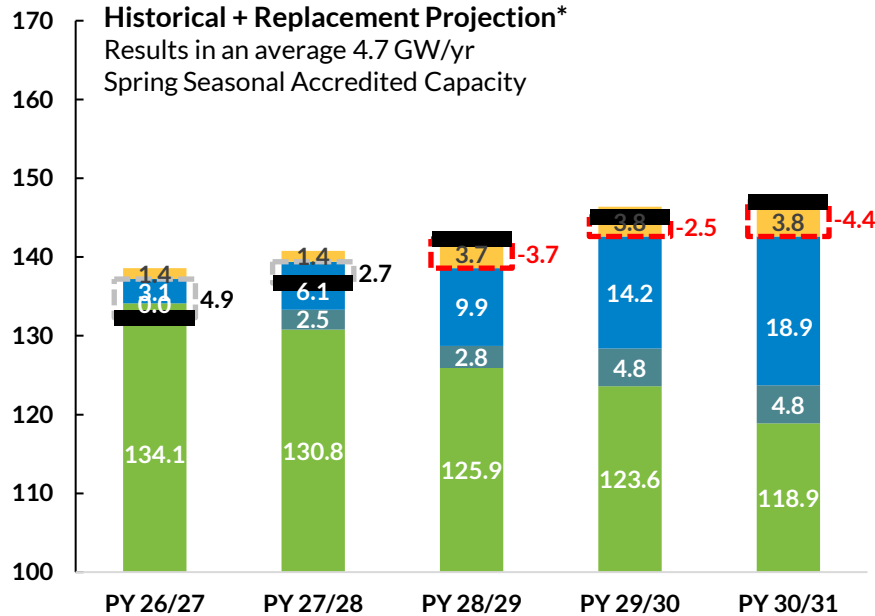
- Red border values indicate the additional potential deficit against the Projected PRMR
- Gray border values indicate the potential surplus against the Projected PRMR

- 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

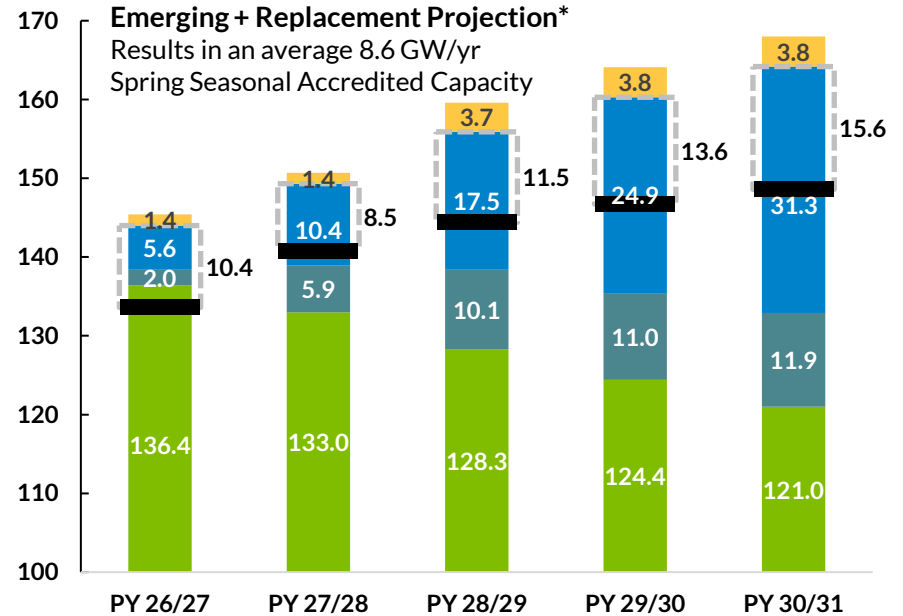
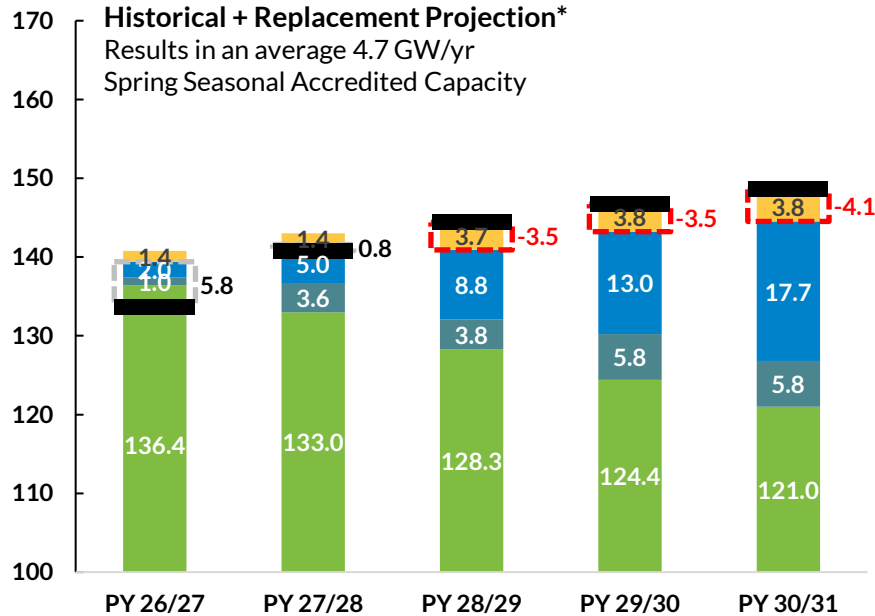
PRMR: Planning Reserve Margin Requirement

- 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

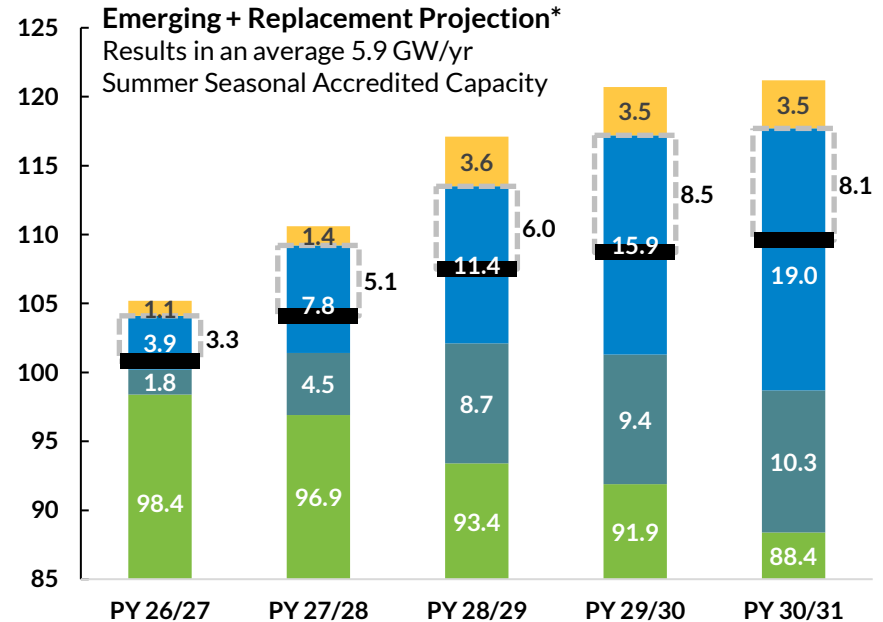
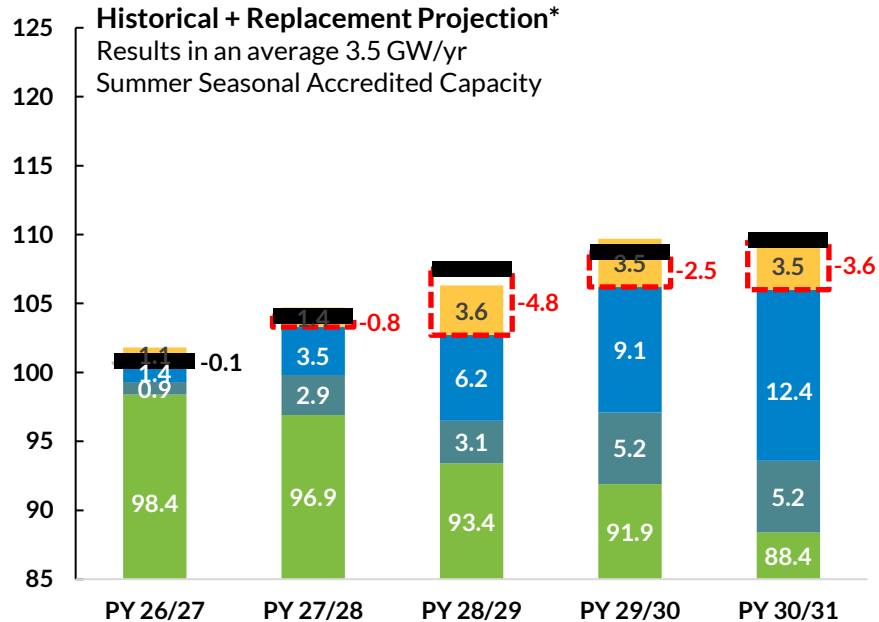
- Red border values indicate the additional potential deficit against the Projected PRMR
- Gray border values indicate the potential surplus against the Projected PRMR

- 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

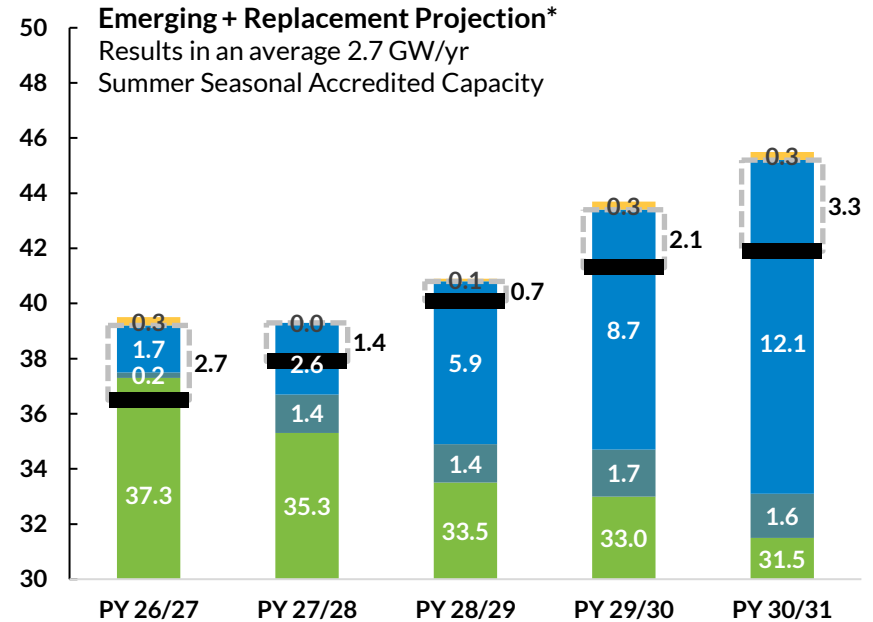
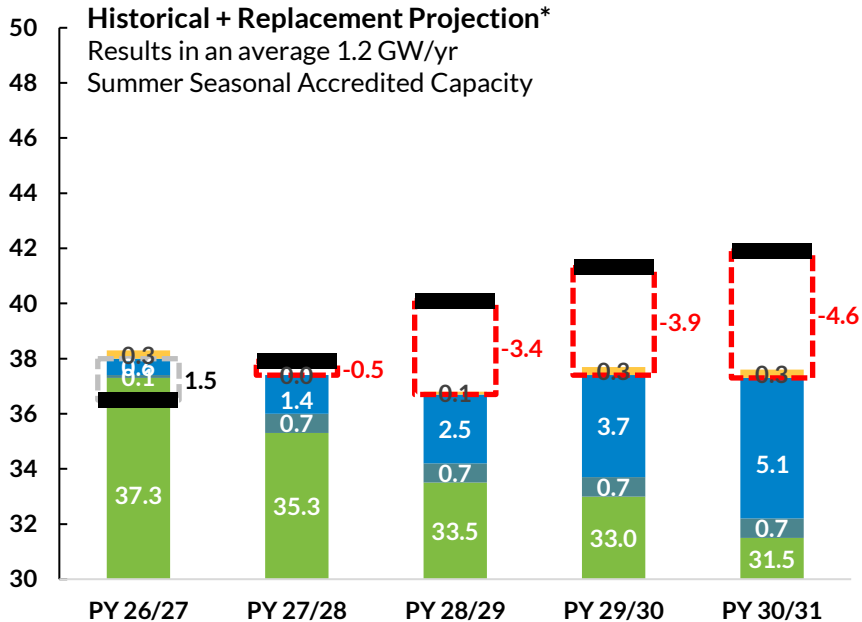
- Red border values indicate the additional potential deficit against the Projected PRMR
- Gray border values indicate the potential surplus against the Projected PRMR

- 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

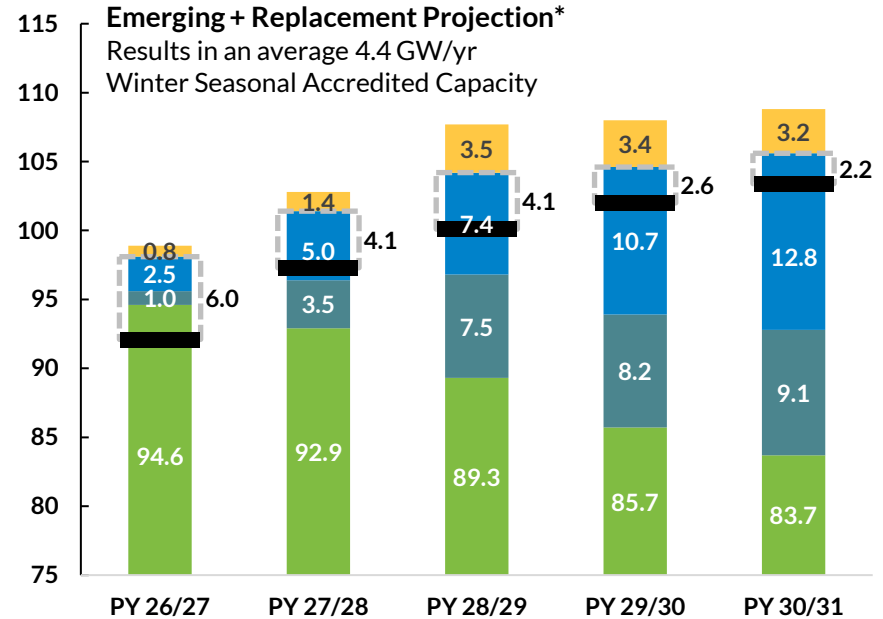
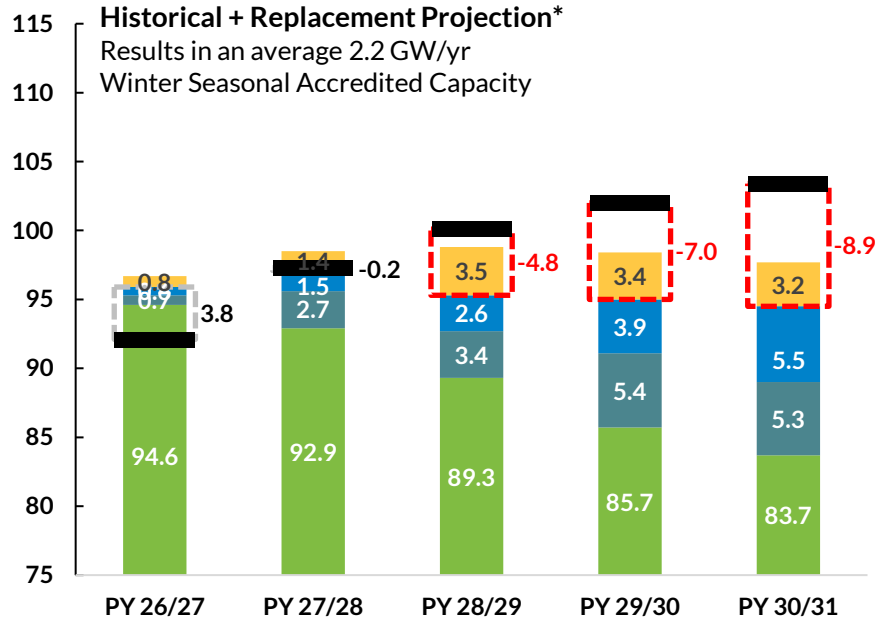
PRMR: Planning Reserve Margin Requirement

- 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



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

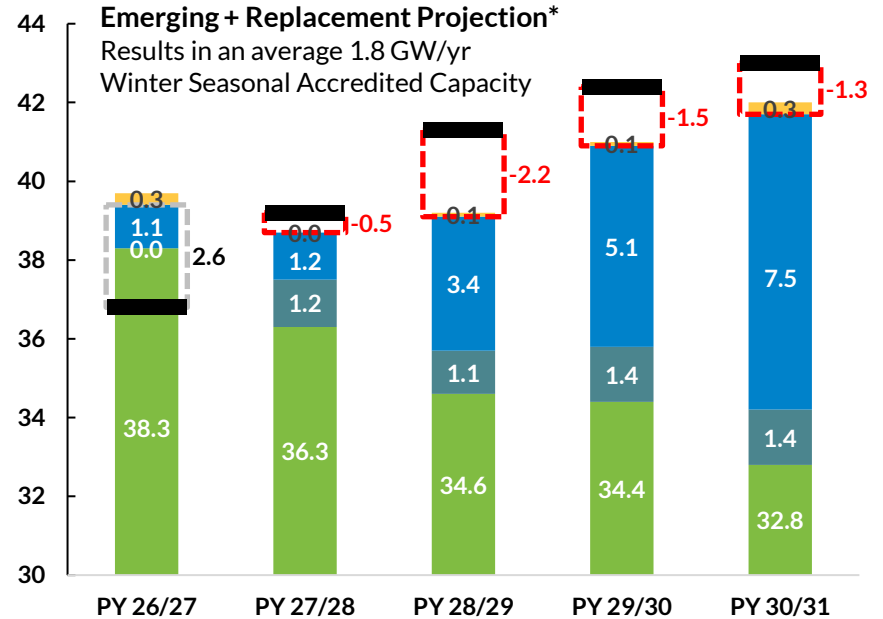
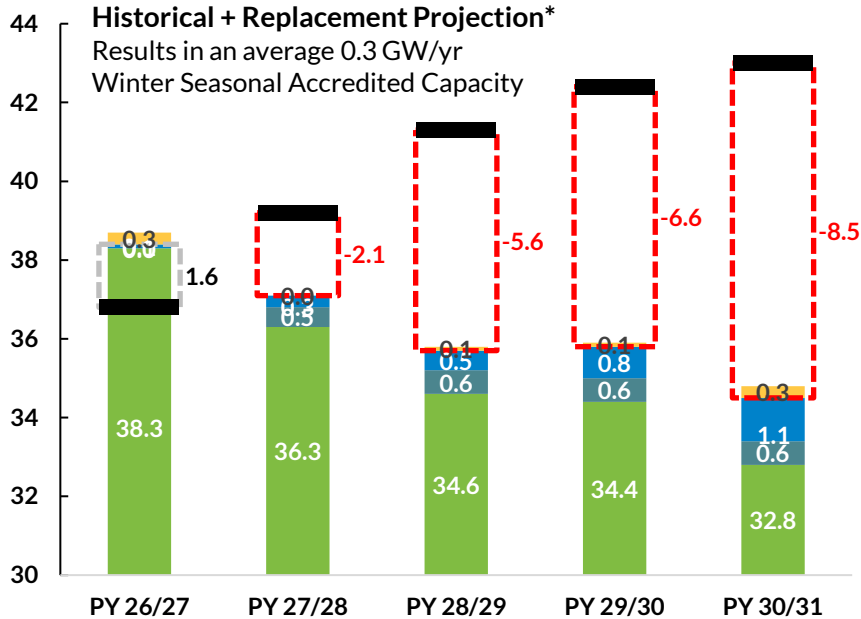
*Using methods for potential New Capacity described on Slide 8
PRMR: Planning Reserve Margin Requirement

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- 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



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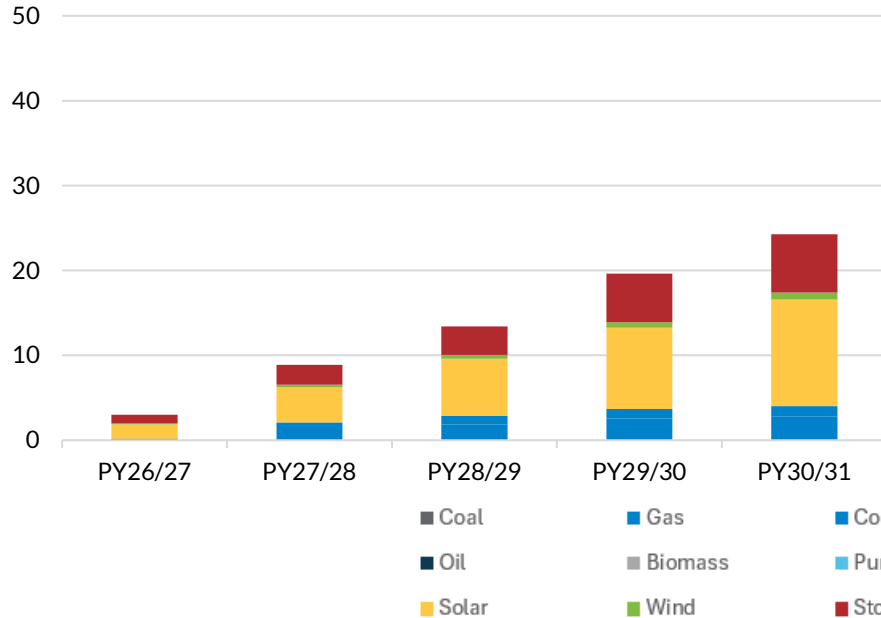
- Capacity accreditation values and Planning Reserve Margin projections based on current practices
- Regional Directional Transfer (RDT) limit of 1900 MW is reflected in this chart

OMS-MISO Survey projections of new resource accreditation value

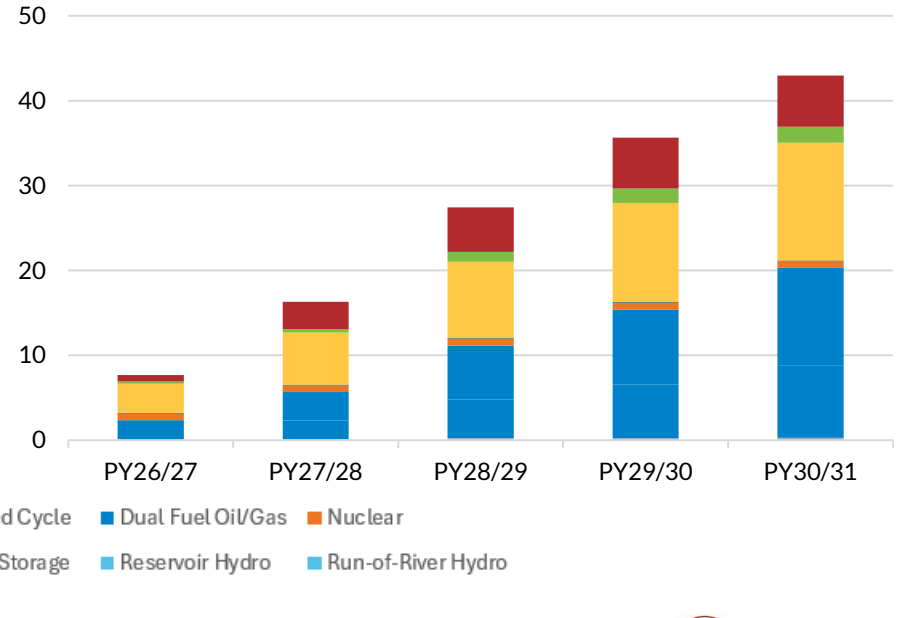
-Status Quo SAC calculations

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)

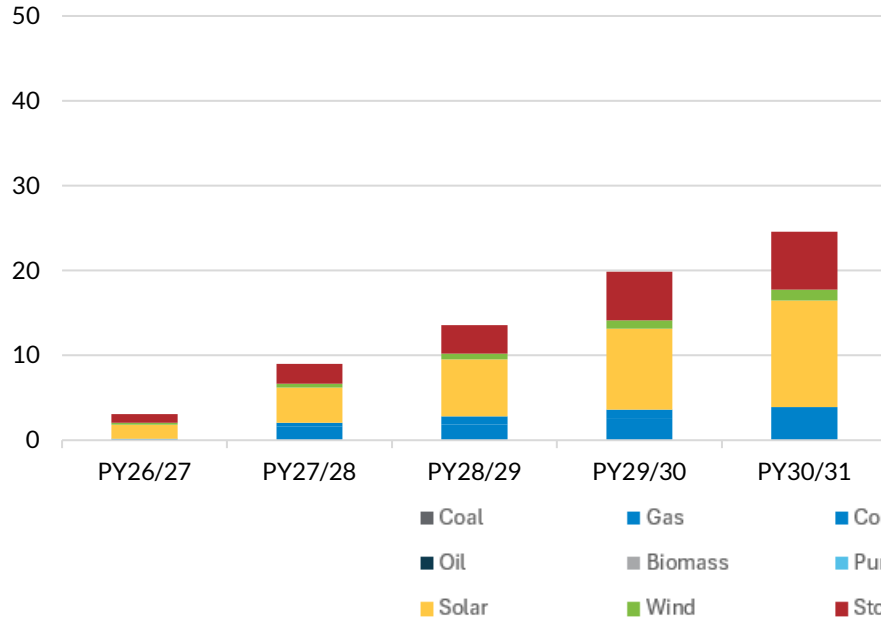


OMS-MISO Survey projections of new resource accreditation value

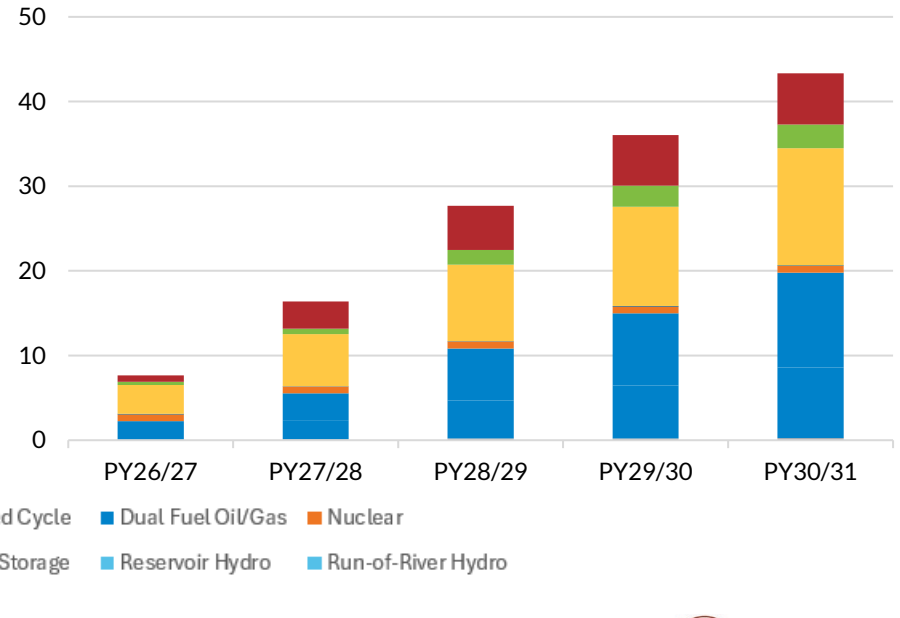
-Status Quo SAC calculations

Projections of New Resource Fuel Mix – Fall

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



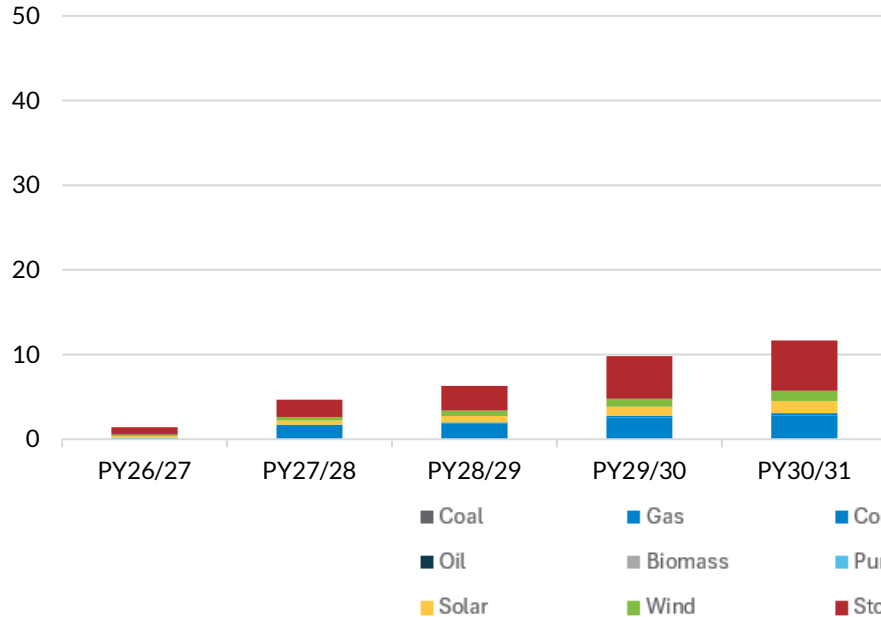
Emerging + Replacement Projection
New Resource Capacity (GW Fall SAC)



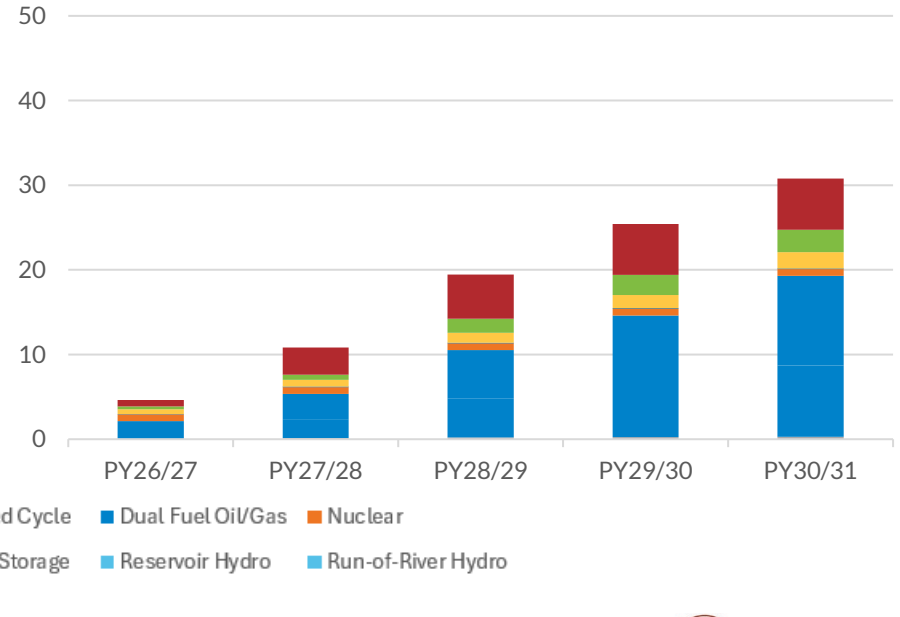
OMS-MISO Survey projections of new resource accreditation value -Status Quo SAC calculations

Projections of New Resource Fuel Mix – Winter

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



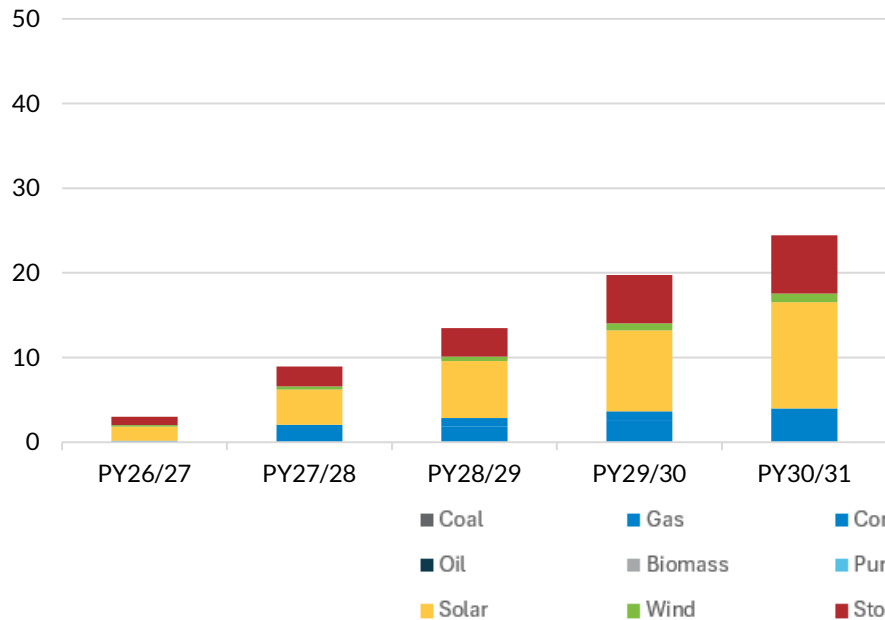
**Emerging + Replacement Projection
New Resource Capacity (GW Winter SAC)**



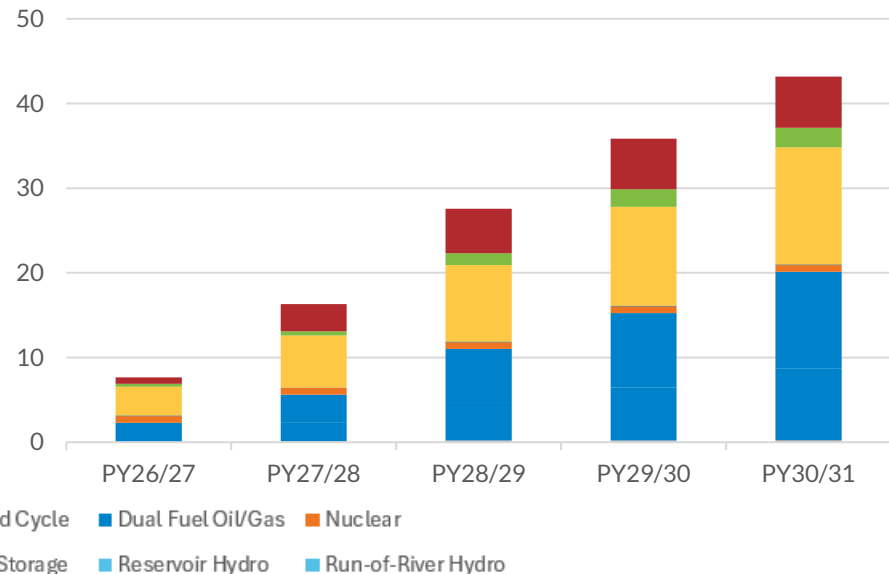
OMS-MISO Survey projections of new resource accreditation value -Status Quo SAC calculations

Projections of New Resource Fuel Mix – Spring

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



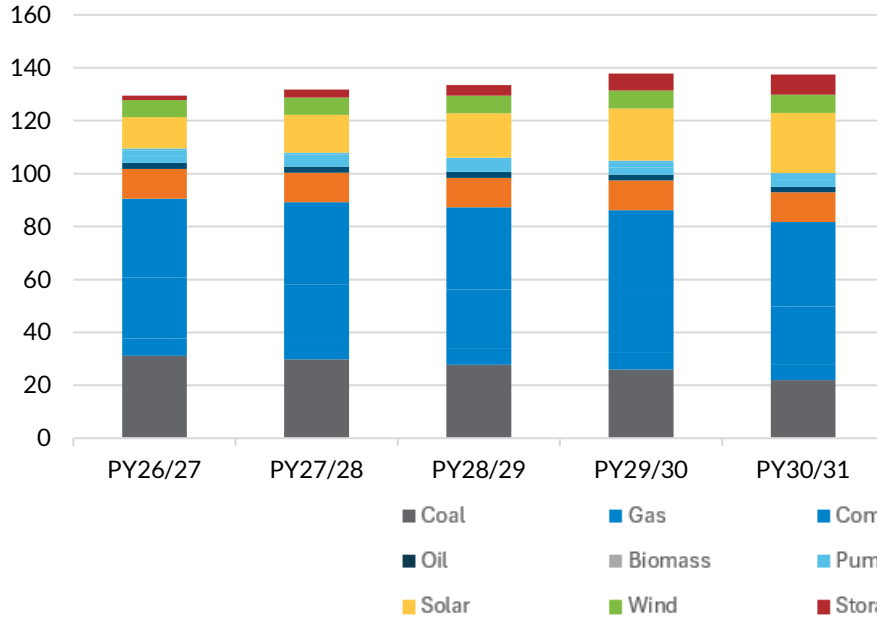
Emerging + Replacement Projection New Resource Capacity (GW Spring SAC)



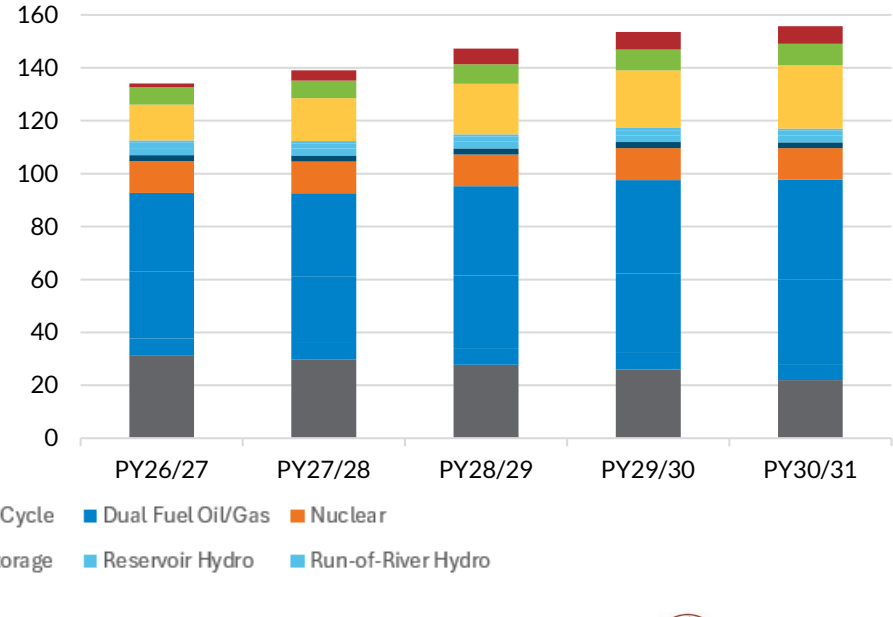
OMS-MISO Survey projections of fleet total resource accreditation value -Status Quo SAC calculations

Combined Projections of Fuel Mix – Summer

Historical + Replacement Projection Total Capacity (GW Summer SAC)



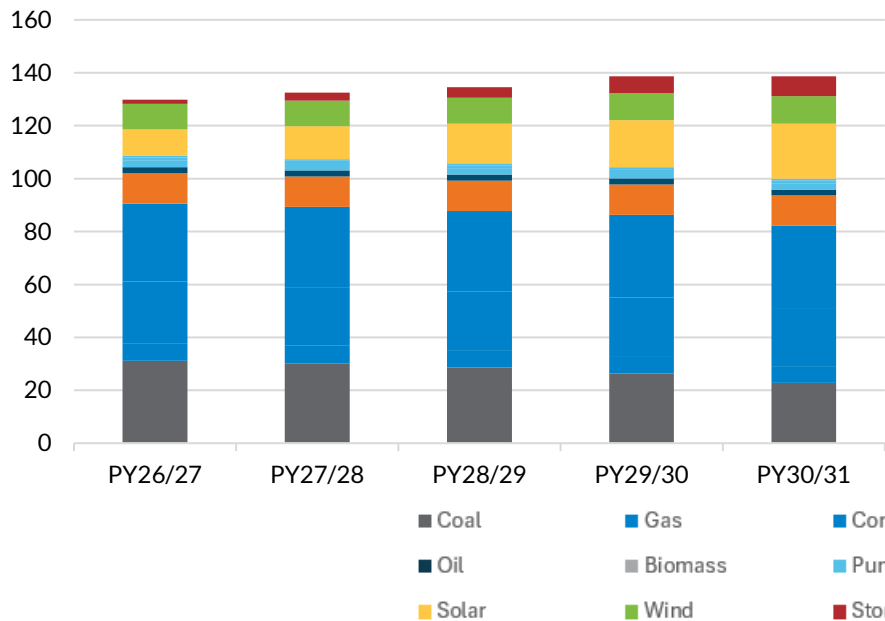
Emerging + Replacement Projection Total Capacity (GW Summer SAC)



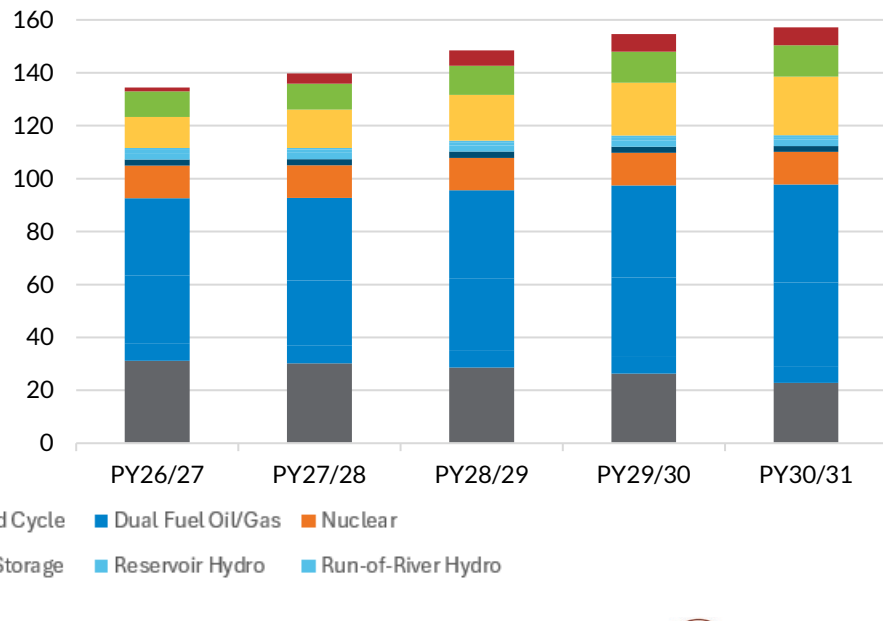
OMS-MISO Survey projections of fleet total resource accreditation value -Status Quo SAC calculations

Combined Projections of Fuel Mix – Fall

Historical + Replacement Projection Total Capacity (GW Fall SAC)



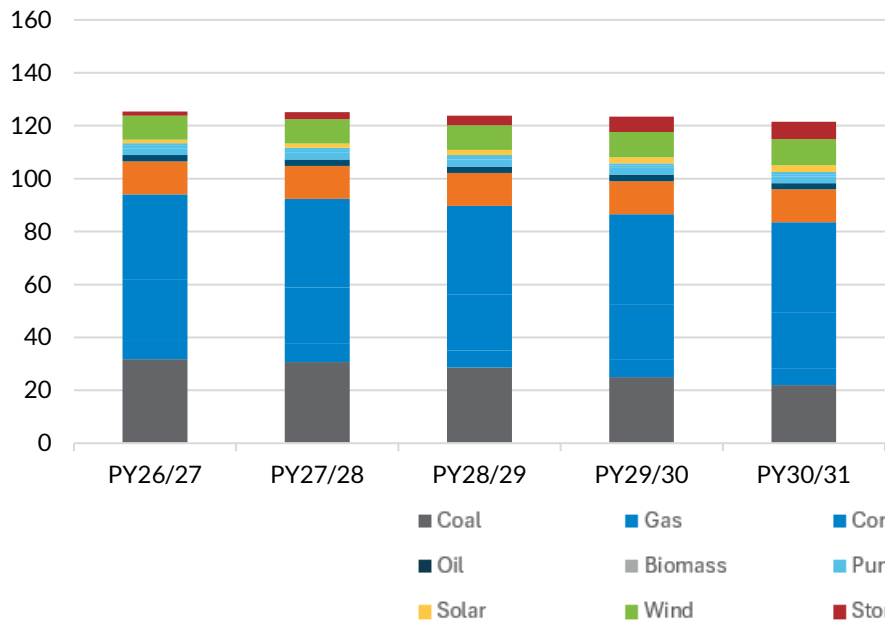
Emerging + Replacement Projection Total Capacity (GW Fall SAC)



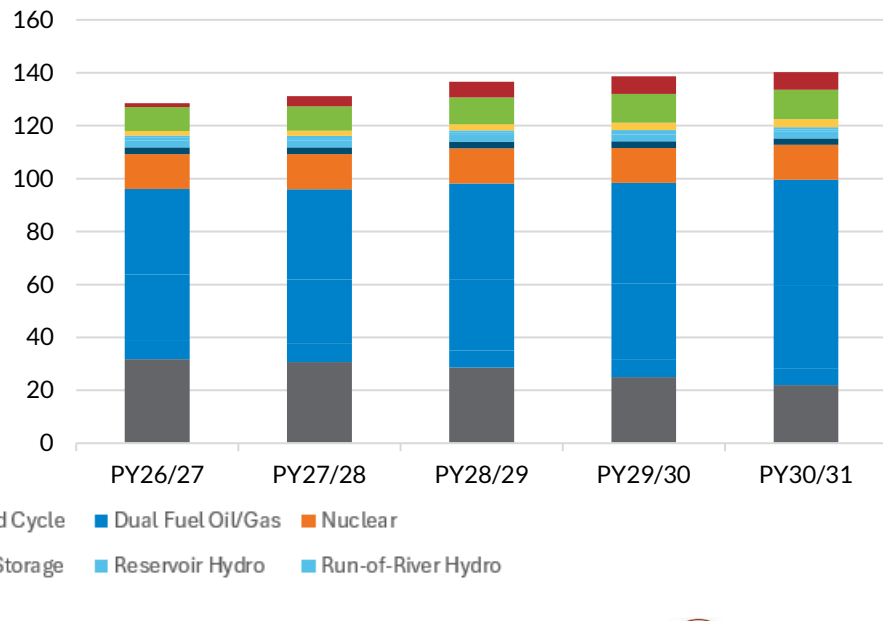
OMS-MISO Survey projections of fleet total resource accreditation value -Status Quo SAC calculations

Combined Projections of Fuel Mix – Winter

Historical + Replacement Projection Total Capacity (GW Winter SAC)



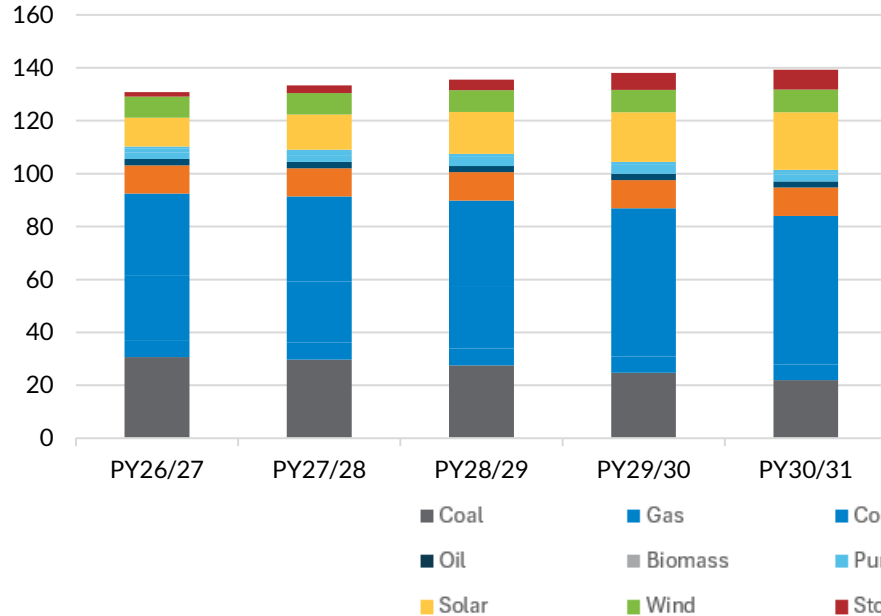
Emerging + Replacement Projection Total Capacity (GW Winter SAC)



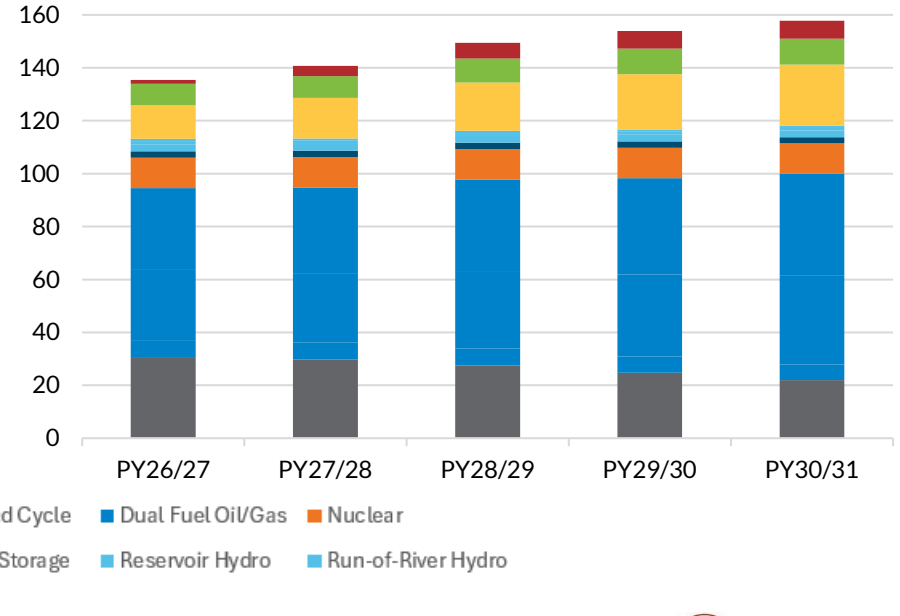
OMS-MISO Survey projections of fleet total resource accreditation value -Status Quo SAC calculations

Combined Projections of Fuel Mix – Spring

Historical + Replacement Projection Total Capacity (GW Spring SAC)



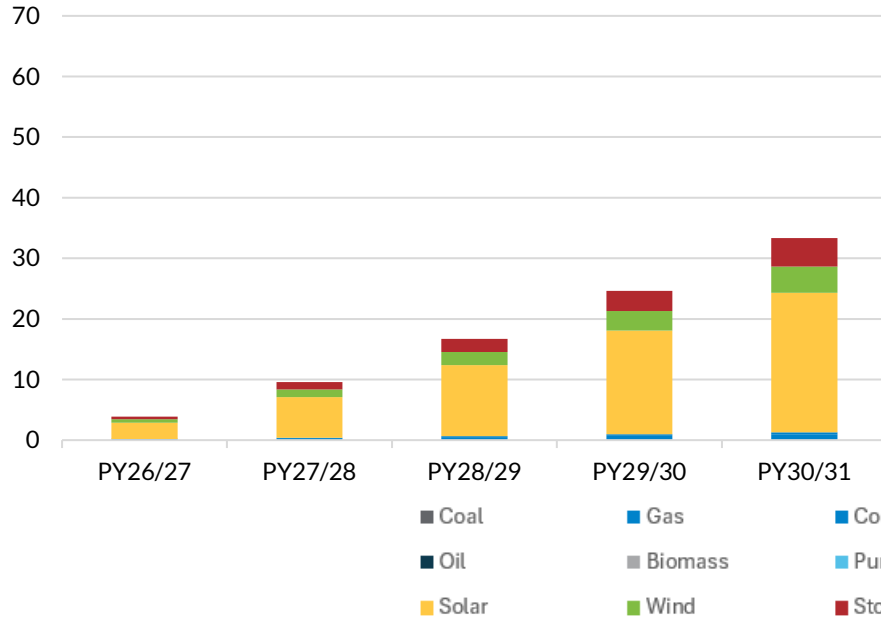
Emerging + Replacement Projection Total Capacity (GW Spring SAC)



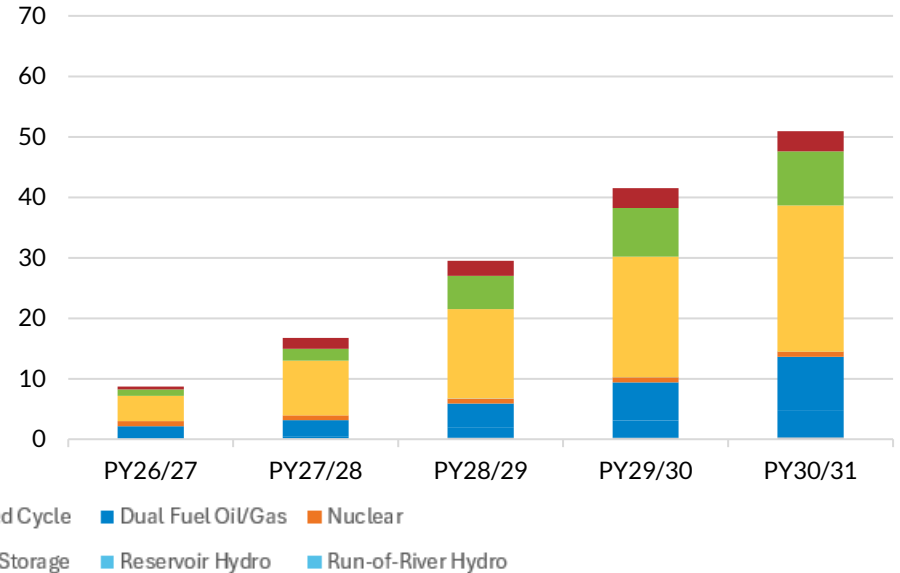
OMS-MISO Survey projections of new resource deliverable nameplate

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

Historical Projection New Resource Nameplate (GW)



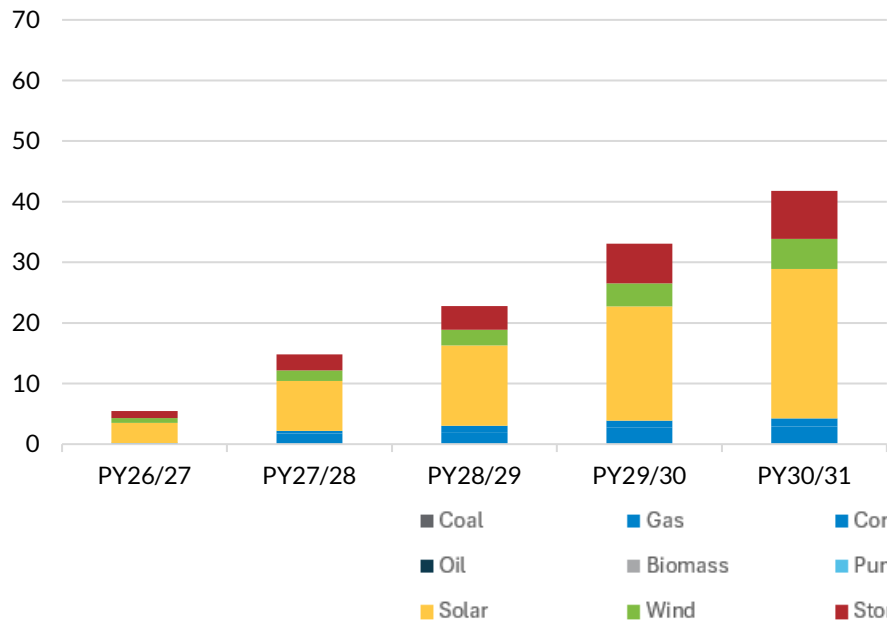
Emerging Projection New Resource Nameplate (GW)



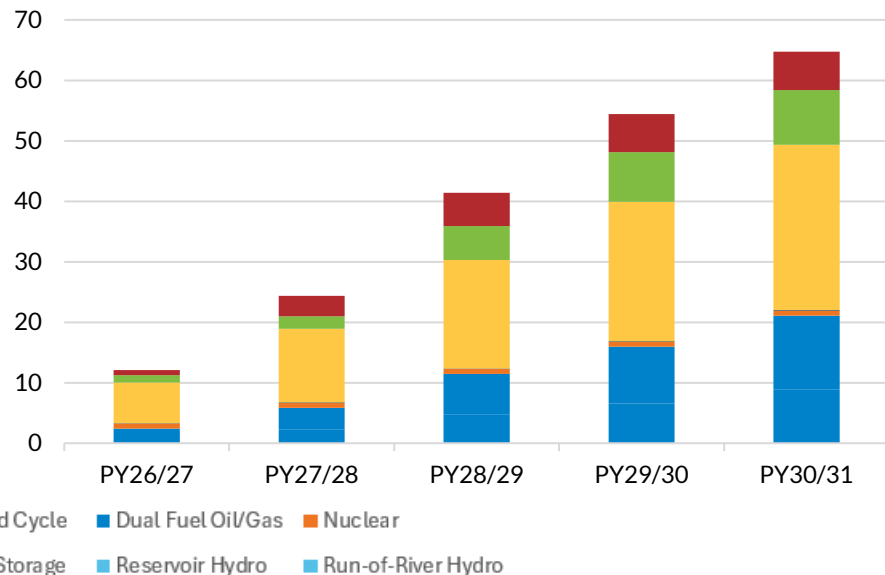
OMS-MISO Survey projections of new resource deliverable nameplate

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

Historical + Replacement Projection New Resource Nameplate (GW)



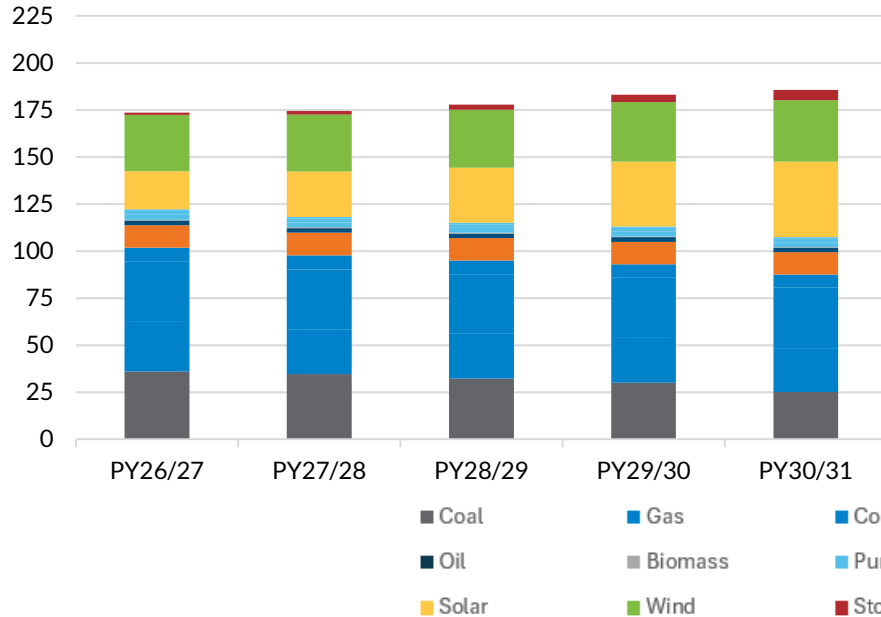
Emerging + Replacement Projection New Resource Nameplate (GW)



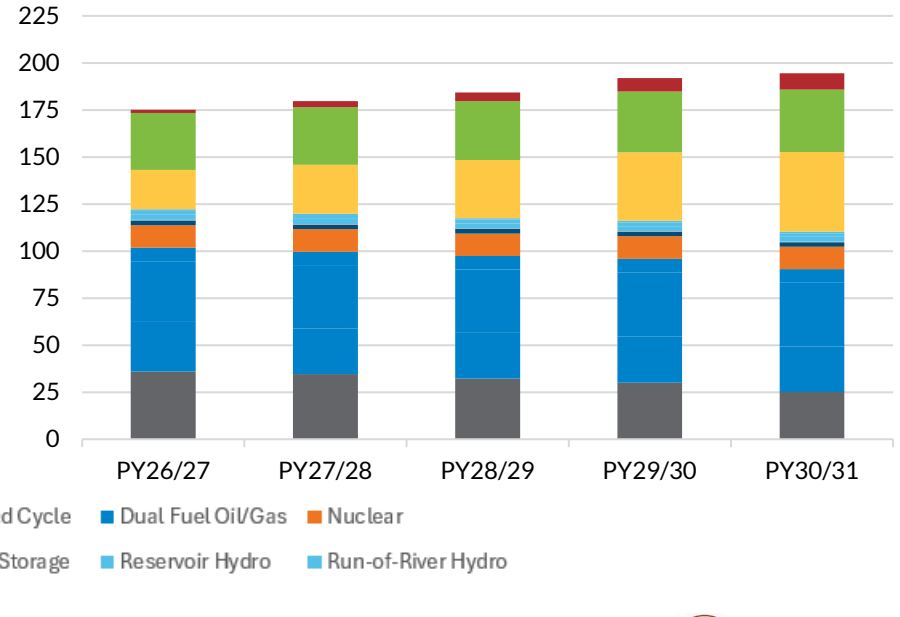
OMS-MISO Survey projections of fleet total deliverable nameplate

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

Historical Projection Total Nameplate (GW)



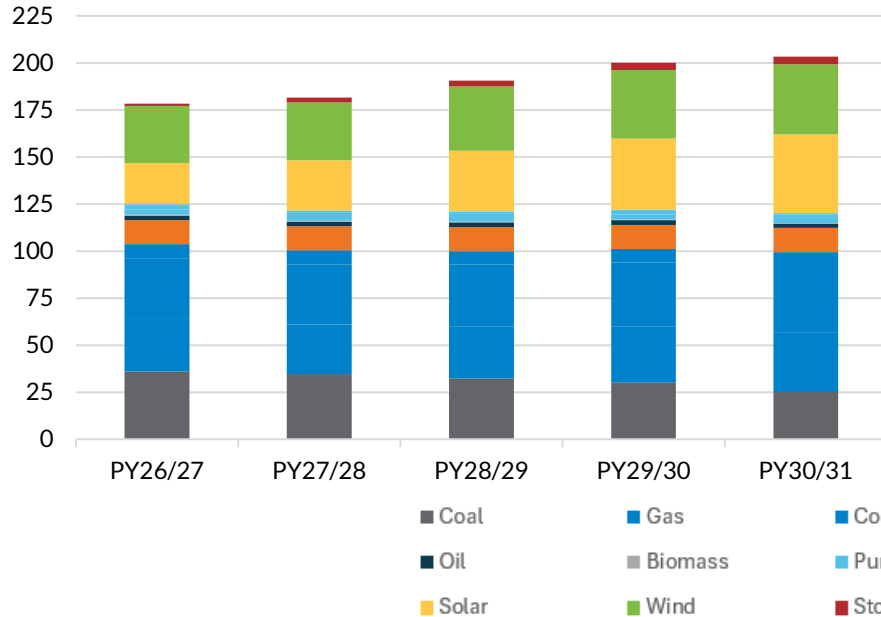
Historical + Replacement Projection Total Nameplate (GW)



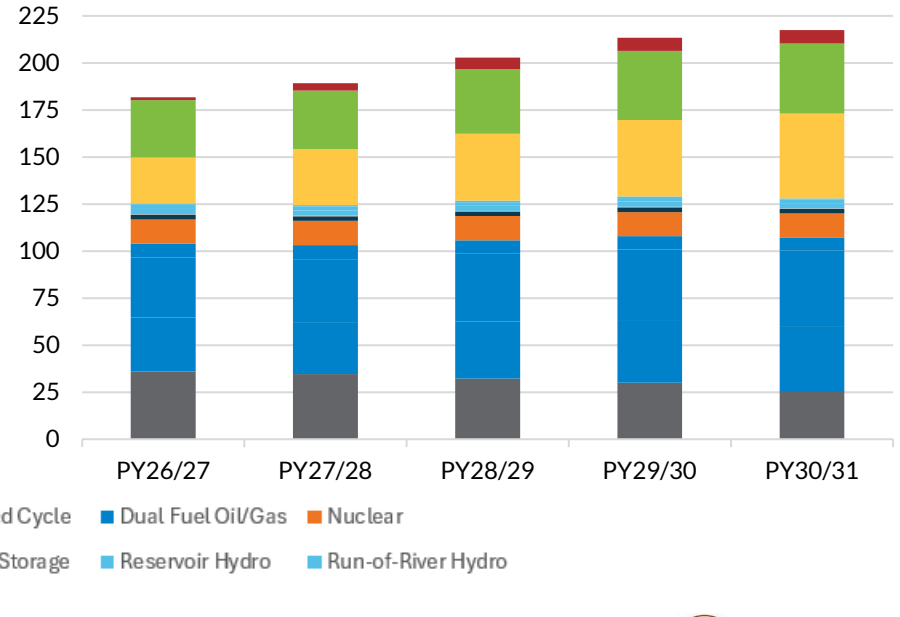
OMS-MISO Survey projections of fleet total deliverable nameplate

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

Emerging Projection Total Nameplate (GW)



Emerging + Replacement Projection Total Nameplate (GW)



Attachment X

Consumers, Complaint, FERC Docket No. EL25-90

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

COMPLAINT REQUESTING FAST TRACK PROCESSING

Consumers Energy Company (“Consumers Energy” or “Company”) files this complaint and request for Fast Track processing against Midcontinent Independent System Operator, Inc. (“MISO”), pursuant to sections 202(c), 306, and 309 of the Federal Power Act (“FPA”),¹ and Rule 206 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission (“FERC” or “Commission”).²

On May 23, 2025, the U.S. Secretary of Energy issued an order pursuant to FPA section 202(c) and section 301(b) of the Department of Energy Organization Act³ declaring 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.”⁴ On that basis, the DOE Order directs both Consumers Energy and MISO to “take all measures necessary to ensure” that Consumers Energy’s J.H. Campbell generation facility in West Olive, Michigan (the “Campbell Plant”), which had been scheduled to cease operations on May 31, 2025, continues to operate.⁵ Since its issuance, Consumers Energy has complied with its obligations

¹ 16 U.S.C. §§ 824a(c), 825e, 825h.

² 18 C.F.R. § 385.206 (2025).

³ 42 U.S.C. § 7151(b).

⁴ U.S. Department of Energy, Order No. 202-25-3, at 2 (May 23, 2025) (“DOE Order”).

⁵ *Id.*

under the DOE Order, and the Campbell Plant is currently being offered into the MISO market and is producing energy when dispatched.

The DOE Order makes clear that “[r]ate recovery is available pursuant to [FPA section 202(c)],” and further directs Consumers Energy to “file with the Federal Energy Regulatory Commission Tariff revisions or waivers necessary to effectuate this order.”⁶ This Complaint is being filed in furtherance of that directive and to ensure that there is a mechanism for Consumers Energy to obtain such rate recovery as is available pursuant to FPA section 202(c) at the appropriate time in the future, likely after the DOE Order expires.

To be clear, *the specific costs, if any, to be recovered by Consumers Energy are not at issue in this Complaint.* Rather, Consumers Energy plans to make a section 202(c) filing after the conclusion of the extended service required by the DOE Order in which it will present, explain, and support what it believes are its just and reasonable costs associated with running the Campbell Plant from the date of the DOE Order, netting out applicable market revenues (its “Order Costs”).⁷ Thus, the determination of recoverable costs will be the subject of a separate FERC proceeding under section 202(c) after the conclusion of the extended service required by the DOE Order. The instant Complaint is limited to ensuring that MISO has the requisite Tariff-based *mechanism* to effectuate Consumers Energy’s cost recovery.

Both Consumers Energy and MISO agree that (1) existing MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (“Tariff”) does not include a mechanism for Consumers Energy to recover costs associated with complying with the Order; and

⁶ *Id.*

⁷ For the avoidance of doubt, consistent with Section 202(c)’s cost recovery language, Consumers Energy reserves all rights to make a demonstration of its just and reasonable Order Costs (net of market revenues) in the subsequent Section 202(c) filing discussed herein, which will be made after the conclusion of the extended service required by the DOE Order.

(2) MISO lacks Tariff authority to unilaterally offer Consumers Energy a section 202(c) rate agreement. Accordingly, Consumers Energy requests that the Commission exercise its authority pursuant to FPA sections 202(c) and 309 to order MISO to adopt a Tariff revision to provide a cost recovery mechanism for Consumers Energy's Order Costs. Consumers Energy requests that the requested MISO Tariff revision will be effective as of the issuance of the DOE Order on May 23, 2025, or such other date as the Commission determines will still permit recovery of Consumers Energy's Order Costs back to the referenced date of the DOE Order.⁸

I. EXECUTIVE SUMMARY

Pursuant to the DOE Organization Act, the authority under section 202(c) to “determine[] that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes” is vested in the Secretary of Energy. That section's authority to “order such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest” is similarly vested in the Secretary. The Commission's role under this particular statutory framework is limited to cost recovery.

As detailed below, the Campbell Plant is a roughly 1400 MW coal-fired generating station that had been scheduled to retire as of May 31, 2025. As soon as the DOE Order was issued, Consumers Energy began incurring and will continue to incur costs to comply with the DOE Order's directive to “take all measures necessary to ensure that the Campbell Plant is available to

⁸ The Company believes that FPA sections 202(c) and 309 provide ample authority for the Commission to grant the relief requested herein. Nonetheless, if the Commission finds it must invoke its FPA Section 206 authority to grant the relief requested herein, Consumers Energy moves for relief under Section 206 in the alternative. *See infra* Section V. Under section 206, the Commission could make the requested Tariff revision effective as of the date of this Complaint.

operate” for the duration of the DOE Order. The precise Order Costs will not be known until after the DOE Order expires on August 21, 2025. Soon thereafter, Consumers Energy will make a separate request to the Commission under section 202(c) for the “compensation or reimbursement” of its Order Costs, net of market revenues, as provided by the statute.

The more immediate issue is that the MISO Tariff currently contains no mechanism to provide compensation to generators in the MISO footprint operating pursuant to section 202(c) emergency orders, and no basis to allocate such costs to reflect the nature of an emergency declared pursuant to section 202(c). This Complaint, therefore, asks the Commission to order MISO to revise its Tariff to provide for allocation of Consumers Energy’s (later-to-be-determined) Order Costs, net of market revenues. This relief is necessary and appropriate for several reasons. For its part, Consumers Energy has no contractual privity or Tariff authority to allocate costs directly to MISO customers. Ordering paragraph (F) of the DOE Order instructs Consumers Energy to “file with the Federal Energy Regulatory Commission Tariff revisions or waivers necessary to effectuate this order.” The same passage further makes clear that “[r]ate recovery is available pursuant to 16 U.S.C. § 824a(c).” Ordering paragraph (E) provides that, “[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.” Finally, DOE sent “carbon copies” of the DOE Order to each sitting FERC Commissioner.

The Commission’s duties and authority to address this Complaint and issue the requested relief are found in sections 202(c), 306, and 309 of the FPA. Importantly, cost recovery under section 202(c) does not invoke the normal ratemaking strictures of FPA sections 205 or 206. Section 202(c) provides independent authority to empower the Commission to “prescribe by

supplemental order such terms as it finds to be just and reasonable, including the compensation or reimbursement which should be paid to or by any such party.” And, to the extent necessary, FPA section 309 supplements the Commission’s authority to take action to implement its section 202(c) responsibilities. Specifically, FPA section 309 grants the Commission “power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules, and regulations as it may find necessary or appropriate to carry out the provisions of this Act.”⁹ To effectuate Consumers Energy’s right to recover the costs of complying with the DOE Order, the MISO Tariff must be amended to create a recovery mechanism. In the absence of an agreement between the parties affected by a 202(c) order, the Commission has the responsibility for determining cost recovery and allocation. As noted above, the actual costs, if any, Consumers Energy seeks to recover will be the subject of a separate filing with the Commission. However, at this juncture, FPA section 309 authorizes the Commission to take measures to ensure its ability “to carry out” its role, pursuant to section 202(c), by requiring adoption of the 202(c) Cost Recovery Mechanism.

Finally, the relief requested herein meets the “just and reasonable” standard of section 202(c)(1). In addition to providing MISO the authority to implement a mechanism for cost recovery, Consumers Energy asks the Commission to order MISO to adopt specific Tariff provisions to allocate its Order Costs (net of market revenues) proportionally to load in MISO Zones 1 through 7 – referred to in the DOE Order as the northern and central regions of MISO.¹⁰ This proposed cost allocation is just and reasonable because, under section 202(c), costs should be allocated based on the scope and nature of the emergency that prompted issuance of the order in question. The DOE Order’s emergency declaration is substantially based on concerns about

⁹ 16 U.S.C. § 825h.

¹⁰ DOE Order at 2.

resource adequacy in MISO generally, and the northern and central regions in particular.¹¹ In other words, the beneficiaries for cost allocation purposes are best determined by reference to the Secretary's definition of the emergency. Under such a regional allocation, Michigan load will of course pay its fair share of Consumers Energy's Order Costs (net of market revenues) because, as the DOE Order points out, MISO Zones 1-7 (*i.e.*, the northern and central zones) include Michigan. But Consumers Energy believes that, whatever the Order Costs turn out to be after netting market revenues, they should be allocated beyond the State of Michigan. Consumers Energy customers are already paying for the cost to fulfill the capacity needs of Zone 7.

In sum, the Commission's duties and authority to address this cost allocation are clear. Consumers Energy respectfully requests that the Commission set a 10-day comment period on this complaint, and issue an order at the earliest opportunity directing MISO to adopt the referenced cost allocation mechanism for the Order Costs of the Campbell Plant.

II. BACKGROUND

A. The Parties

1. Consumers Energy Company

Consumers Energy is a public utility that serves approximately 1.9 million electric customers and 1.8 million natural gas customers in Michigan's Lower Peninsula. Consumers Energy is wholly owned by, and one of the two principal subsidiaries of, CMS Energy Corporation, which is a publicly traded company. Consumers Energy owns and operates generating facilities and non-jurisdictional distribution facilities. Consumers Energy is a member of MISO, a market participant in the MISO wholesale markets, and takes transmission service in MISO.

¹¹ Because the Order cites the "northern and central zones," Consumers Energy believes the best read of the DOE Order is that the emergency identified in the Order exists in Zones 1-7 and would not reach "MISO South."

2. MISO

MISO is an Independent System Operator and Regional Transmission Organization and is authorized by the Commission to provide open access transmission service and to administer wholesale energy, capacity, and ancillary services markets in portions of the Midwest region of the United States, as well as certain other regions. MISO also administers the MISO Tariff, which governs such markets. MISO includes ten separate zones. MISO's northern and central regions are zones 1 through 7.

B. Factual Background

1. The Campbell Plant

The Campbell Plant is a coal-fired electric generation plant located in West Olive, Michigan, with a summer capacity of approximately 1400 MW. The Campbell Plant consists of three units:

- Unit 1, which commenced commercial operations in 1962, has a summer capacity of approximately 260 MW and is wholly owned by the Company;
- Unit 2, which commenced commercial operations in 1967, has a summer capacity of approximately 280 MW and is wholly owned by the Company; and
- Unit 3, which commenced commercial operations in 1980, has a summer capacity of approximately 840 MW and is majority owned by the Company.¹²

Pursuant to an integrated resource plan the Company filed with the Michigan Public Service Commission ("MPSC") in 2021,¹³ and a settlement arising from that filing that was

¹² Wolverine Power Supply Cooperative, Inc. ("Wolverine") and the Michigan Public Power Agency ("MPPA") own, respectively, 1.89% and 4.80% interests in Unit 3. As such they may have costs associated with the DOE Order and they may also realize market revenue due to Campbell Plant operation under the DOE Order. Consumers Energy has been in communication with Wolverine and MPPA and all three parties agree to cooperate to ensure appropriate cost recovery by Wolverine and MPPA in connection with the DOE Order.

¹³ In the Matter of the Application of Consumers Energy Company for Approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief, Application MPSC

approved by an order of the MPSC in 2022, the Campbell Plant was scheduled to be retired on May 31, 2025.¹⁴

The planned retirement of the Campbell Plant was also studied and approved by MISO, pursuant to MISO Tariff provisions. The DOE Order recognizes that the planned retirement of the Campbell Plant has been incorporated into supply forecasts for MISO, but notes that the North American Electric Reliability Corporation’s 2025 Summer Reliability Assessment “still anticipates ‘elevated risk of operating reserve shortfalls.’”¹⁵ The DOE Order also cites MISO’s Planning Resource Action Results for Planning Year 2025-26, which “note that for the northern and central zones, which includes Michigan, ‘new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources.’”¹⁶

2. The DOE Order

The DOE Order states that MISO “faces potential tight reserve margins during the summer 2025 period, particularly during periods of high demand or low generation resource output,” “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,” and 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).”¹⁷ The DOE Order also points out that

Case No. U-21090-003, (filed June 30, 2021), <https://mipsc.my.site.com/sfc/servlet.shepherd/version/download/068t000000Nib8YAAR>.

¹⁴ *Order Approving Settlement*, MPUC Case No. U-21090-0901 (June 23, 2022), <https://mipsc.my.site.com/sfc/servlet.shepherd/version/download/0688y000003KjSDAA0>.

¹⁵ DOE Order at 2 (citations omitted).

¹⁶ *Id.* (citation omitted).

¹⁷ *Id.* at 1, 2.

“MISO’s Planning Resource Auction Results for Planning Year 2025-26, released in April 2025, note that for the northern and central zones, which includes Michigan, ‘new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources.’”¹⁸

Based on the foregoing determination, the DOE Order directs the Company and MISO to “take all measures necessary to ensure that the Campbell Plant is available to operate” until the DOE Order’s expiration in August 2025.¹⁹ The DOE Order explains that “[r]ate recovery is available pursuant to 16 U.S.C. § 824a(c)” and directs Consumers “to file with the Federal Energy Regulatory Commission Tariff revisions or waivers necessary to effectuate” the DOE Order.²⁰ The DOE Order also directs MISO, among other things, to “take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers”²¹ and “provide the Department of Energy . . . with information concerning the measures it has taken and is planning to take to ensure the operational availability and economic dispatch of the Campbell Plant consistent with the public interest.”²² The DOE Order further directs that “[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.”²³

¹⁸ *Id.* at 2 (citation omitted).

¹⁹ *Id.* at Ordering Paragraph A.

²⁰ *Id.* at Ordering Paragraph F.

²¹ *Id.* at Ordering Paragraph A.

²² *Id.* at Ordering Paragraph D.

²³ *Id.* at Ordering Paragraph E.

3. Company Actions to Comply with the DOE Order

Upon receiving the DOE Order, Consumers Energy has undertaken significant efforts to comply with its directives, including procurement of fuel, review and planning for maintenance, and numerous other undertakings.

The Company has established a regulatory asset to account for all costs of running the Campbell Plant from the date the DOE Order was issued and will seek recovery of such costs in a future filing. The 202(c) Cost Recovery Mechanism being requested herein will be the Tariff mechanism for the approved recovery.

C. Overview of FPA Section 202 and DOE's Implementing Regulations

FPA section 202(c) was established by the Public Utility Act of 1935 and originally provided the emergency authority to the Federal Power Commission.²⁴ In 1977, the Department of Energy Organization Act (“DOE Organization Act”) transferred the authority to determine the existence of an emergency to the Secretary of the Energy.²⁵

Section 202(c) of the FPA provides, in relevant part, as follows:

During the continuance of any war in which the United States is engaged, or whenever the Commission determines that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes, the Commission shall have authority, either upon its own motion or upon complaint, with or without notice, hearing, or report, to require by order such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest. *If the parties affected by such order fail to agree upon the terms of any*

²⁴ See Public Utility Holding Company Act of 1935, Pub. L. No. 74-333, pt. II at 849 (1935) (codified at 16 U.S.C. § 824a(c)).

²⁵ See Department of Energy Organization Act, Pub. L. No. 95-91, tit. III, 91 Stat. 577-78 (1977) (codified at 42 U.S.C. § 7151). As a result, the word “Commission” refers to the Secretary of Energy for purposes of determining the emergency and ordering the emergency generation.

arrangement between them in carrying out such order, the Commission, after hearing held either before or after such order takes effect, may prescribe by supplemental order such terms as it finds to be just and reasonable, including the compensation or reimbursement which should be paid to or by any such party.

16 U.S.C. 824a(c)(1) (emphasis added).

In 1981, the DOE promulgated a rule to implement the rate aspects of FPA section 202(c).

That rule provides, in relevant part:

In the event that the DOE determines that an emergency exists under [FPA] section 202(c), and the “entities” are unable to agree on the rates to be charged, the DOE shall prescribe the conditions of service and refer the rate issues to the Federal Energy Regulatory Commission for determination by that agency in accordance with its standards and procedures.

10 C.F.R. § 205.376 (emphasis added) (“DOE Referral Regulation”).

III. RELIEF REQUESTED

Consumers Energy requests that the Commission direct MISO to revise the MISO Tariff to include a 202(c) Rate Recovery Mechanism in the form included herewith as Attachment A in such manner as to provide recovery of Consumers Energy’s Order Costs dating back to the issuance of the DOE Order.

IV. ARGUMENT

A. The Company Has a Right to Recover Costs Associated with the DOE Order, and Such Costs Can Be Determined After-the-Fact

FPA section 202(c) confers the right to recover costs associated with an order issued pursuant to its emergency authority. When the parties affected cannot agree on such costs, the statute charges the Commission with the responsibility to determine them. Importantly, FERC’s rate determinations pursuant to section 202(c) can occur after a section 202(c) order terminates, and after the conclusion of the compelled generation or provision of jurisdictional service.

1. Parties Subject to a Section 202(c) Order Are Entitled to Recover Associated Costs, Subject to Commission Approval

There can be no question that Consumers Energy has a right to recover its Order Costs, net of market revenues. This is confirmed by the plain language of FPA section 202(c), the DOE Referral Regulation, and the DOE Order, itself:

- FPA section 202(c): If the parties affected by such order fail to agree upon the terms of any arrangement between them in carrying out such order, the Commission, after hearing held either before or after such order takes effect, may prescribe by supplemental order such terms as it finds to be just and reasonable, *including the compensation or reimbursement* which should be paid to or by any such party.²⁶
- DOE Referral Regulation: In the event that the DOE determines that an emergency exists under [FPA] section 202(c), and the “entities” are unable to agree on the rates to be charged, *the DOE shall* prescribe the conditions of service and *refer the rate issues to the Federal Energy Regulatory Commission for determination by that agency in accordance with its standards and procedures.*²⁷
- DOE Order: “Rate recovery is available pursuant to [FPA section 202(c)].”²⁸

Indeed, recovery of Order Costs is mandated by the U.S. Constitution. Specifically, the Fifth Amendment Takings Clause bars the federal government from taking private property for

²⁶ 16 U.S.C. § 824a(c)(1) (emphasis added).

²⁷ 10 C.F.R. § 205.376 (emphasis added).

²⁸ DOE Order at Ordering Paragraph E.

public use without just compensation.²⁹ For the avoidance of doubt, Consumers Energy only seeks to recover its Order Costs *net of market revenues* earned from the Campbell Plant’s operation.

2. Pursuant to the Commission’s Section 202(c) Rate Authority, Costs Can Be Determined and Recovered *After* the Emergency Generation or Provision of Jurisdictional Service

As described below, both the plain language of section 202(c) and prior Commission precedent demonstrate that appropriate compensation can be determined and recovered after the term of an order declaring an emergency and/or requiring provision of jurisdictional service. Moreover, the prior notice requirements and related filed rate doctrine and rule against retroactive ratemaking pursuant to FPA sections 205 and 206 do not apply in the context of determining compensation pursuant to FPA section 202(c), which provides independent ratemaking authority and includes its own “just and reasonable” standard.

First, section 202(c)’s plain language: After an emergency section 202(c) order “takes effect,” the statute expressly contemplates “supplemental” orders regarding “compensation or reimbursement.”³⁰ The use of the word “reimbursement” indicates an after-the-fact approach. Together, this language demonstrates that, unlike FPA section 205 (which requires prior notice and approval of rates), or section 206 (which allows only prospective fixing of rates or charges by the Commission), the Commission’s rate authority under section 202(c) is broader, and not constrained in the same ways that it is under sections 205 and 206.

Second, Commission precedent: A prior FERC ratemaking proceeding pursuant to section 202(c) demonstrates that costs can be determined and recovered after-the-fact. Specifically, in

²⁹ U.S. Const. amend. V (“[N]or shall private property be taken for use, without just compensation.”); *see, e.g., Duquesne Light Co. v. Barasch*, 488 U.S. 299, 308 (1989) (“If the rate does not afford sufficient compensation, the State has taken the use of utility property without paying just compensation . . .”).

³⁰ 16 U.S.C. § 824a(c).

2002, the Secretary of Energy issued an order determining that an emergency existed on Long Island and directing Cross-Sound Cable Company, LLC (“CSC”) “to operate the Cross-Sound Cable and related facilities in order to transmit and deliver electric capacity and/or energy [when and in such amounts] as may be scheduled and purchased by the Long Island Power Authority (LIPA).”³¹ The DOE Order was effective from the date of issuance until October 1, 2002. On December 6, 2002, pursuant to the DOE Referral Regulation, the Secretary referred to FERC “the matter of compensation to [CSC] for costs incurred providing transmission to [LIPA] in compliance with Emergency Order No. 202-02-1.”³² On December 30, 2002, the Commission issued an order establishing procedures for the resolution of the compensation question.³³ After some initial briefing, the Commission suspended the procedural schedule and directed the parties to engage in mediation.³⁴ On June 4, 2004, the Commission issued an order approving an uncontested settlement between LIPA and CSC that resolved all issues regarding compensation to CSC in connection with the 202(c) order that terminated on October 1, 2002.³⁵

Third, the inapplicability of constraints on the Commission’s ratemaking authority pursuant to FPA sections 205 and 206: The Commission’s core responsibility of ensuring just and reasonable rates for jurisdictional sales and services is typically carried out pursuant to FPA sections 205 and 206 – and it is subject to certain well-established doctrines that arise directly from the statutory language of those two FPA provisions.

³¹ *U.S. Dept. of Energy*, 101 FERC ¶ 61,389 at P 3 (2002) (citing Emergency Order No. 202-02-1).

³² *U.S. Dept. of Energy*, 107 FERC ¶ 61,258 at P 1 (2004).

³³ *U.S. Dept. of Energy*, 101 FERC ¶ 61,389.

³⁴ *U.S. Dept. of Energy*, 107 FERC ¶ 61,258 at P 1.

³⁵ *Id.* P 3.

Section 205 of the FPA requires public utilities to file with the Commission any rates and charges that are subject to the Commission’s jurisdiction, with the required prior notice, and it requires the Commission to ensure the justness and reasonableness of such rates.³⁶ A public utility is only authorized to charge the rate on file with the Commission, and changes to such rates must be prospective.³⁷

Section 206 of the FPA empowers the Commission, upon its own motion or in response to a complaint, to address existing rates that may have become unjust or unreasonable.³⁸ If FERC makes such a determination, it has the authority to determine the “just and reasonable rate, charge, classification, rule, regulation, practice or contract to be thereafter observed” – but this authority is prospective.

These statutory provisions “mandating the open and transparent filing of rates and broadly proscribing their retroactive adjustment are known collectively as the ‘filed rate doctrine.’”³⁹ The filed rate doctrine prevents “‘a regulated seller of [power] . . . from collecting a rate other than the one filed with the Commission,’ and ‘the Commission itself’ cannot retroactively ‘impos[e] a rate increase for [power] already sold.’”⁴⁰ Similarly, the rule against retroactive ratemaking “prohibits the Commission from adjusting current rates to make up for a utility’s over- or under-collection in prior periods.”⁴¹

³⁶ 16 U.S.C. § 824d(c).

³⁷ *W. Deptford Energy, LLC v. FERC*, 766 F.3d 10, 12 (D.C. Cir. 2014) (“[U]tilities are forbidden to charge any rate other than the one on file with the Commission.”); *Okla. Gas & Elec. Co. v. FERC*, 11 F.4th 821, 829 (D.C. Cir. 2021).

³⁸ 16 U.S.C. § 824e(a).

³⁹ *Old Dominion Elec. Coop. v. FERC*, 892 F.3d 1223, 1226-27 (D.C. Cir. 2018).

⁴⁰ *Id.* at 1227 (quoting *Ark.-La. Gas Co. v. Hall*, 453 U.S. 571, 578 (1981)).

⁴¹ *Towns of Concord, Norwood, and Wellesley Mass. v. FERC*, 955 F.2d 67, 71 n.2 (D.C. Cir. 1992).

The prior notice and other strictures associated with ratemaking pursuant to FPA sections 205 and 206 do not apply under section 202(c) because those requirements are recognized to be rooted in the statutory language of FPA sections 205 and 206.⁴² In contrast to FPA sections 205(c) and 206(a), FPA section 202(c) does not have a prior notice requirement and it does not mandate the filing of rate schedules or the prospective fixing of charges. Rather, in the absence of agreement between “the parties affected by such [emergency] order,” section 202(c) permits the Commission to “prescribe by supplemental order such terms as it finds to be just and reasonable, including the compensation or reimbursement which should be paid to or by any such party.”⁴³

The independent nature of the Commission’s rate authority under section 202(c) is further supported by the fact that it is only triggered if the parties affected by the relevant 202(c) order are unable to reach an agreement.⁴⁴ In *San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Services*, the Commission explained that “[t]he statute provides *no role* for the Commission in the event the parties agree on the rates that will apply to the transactions [pursuant to FPA section 202(c)].”⁴⁵ The primacy that the FPA accords to the 202(c) rate determination reached by agreement of the parties is very different from traditional ratemaking rules under sections 205 and 206, which prescribe detailed filing and cost support requirements.⁴⁶

⁴² *Id.* at 71-72 (“[I]t is generally agreed that with respect to the Federal Power Act, the filed rate doctrine rests on two provisions: section 205(c), which requires utilities to file rate schedules with the Commission, and section 206(a), which allows the Commission to fix rates and charges, but only prospectively.”) (footnote omitted).

⁴³ 16 U.S.C. § 824a(c)(1).

⁴⁴ *Id.* (“If the parties affected by such order fail to agree upon the terms of any arrangement between them in carrying out such order, the Commission, . . . may prescribe . . .”).

⁴⁵ 97 FERC ¶ 61,275, at 62,196 (2001) (emphasis added) (subsequent history omitted).

⁴⁶ *See, e.g.*, 18 C.F.R § 35.13 and § 385.206 (2024).

Finally, section 202(c) includes its own “just and reasonable” standard when making rate determinations.

For all of the foregoing reasons, the recovery of costs associated with a FPA section 202(c) order is separate and distinct from rate determinations made under FPA sections 205 and 206.

B. The Commission Should Require MISO to Revise the Tariff to Include the Proposed 202(c) Rate Recovery Mechanism

1. Regional Allocation of Costs is Appropriate to Reflect the Scope and Nature of the Emergency Identified by the Secretary

As discussed above in Section II.B.2, the DOE Order identifies reliability risks in MISO, particularly in the northern and central zones, as the basis for declaring an emergency and ordering the continued operation of the Campbell Plant until August 21, 2025. In light of the scope and nature of the declared emergency, allocating Consumers Energy’s Order Costs (net of market revenues) to load serving entities (“LSEs”) in MISO’s northern and central zones (which would include Michigan) comports with section 202(c)’s just and reasonable standard because the DOE Order identified reliability risks in those MISO zones as the basis for declaring the emergency.

While this case is not governed by sections 205 or 206, general beneficiary pays/cost-causation principles commonly invoked in connection with the Commission’s rate authority nevertheless provide a useful framework for analyzing cost allocation under 202(c).⁴⁷ Here, the Secretary of Energy has determined the scope and nature of an emergency, and the compelled generation or jurisdictional service needed to address it. Consequently, to determine appropriate cost recovery pursuant to FPA section 202(c), the beneficiary pays/cost-causation determination should track the emergency identified in the 202(c) order at issue. Any other approach would

⁴⁷ The beneficiary pays/cost-causation principle requires costs to be allocated to those who cause the costs to be incurred and reap the resulting benefits. *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41, 87 (D.C. Cir. 2014) (citing *Nat’l Ass’n of Regul. Util. Comm’rs v. FERC*, 475 F.3d 1277, 1285 (D.C. Cir. 2007)).

create a risk of conflict between the emergency 202(c) order and a subsequent analysis of cost-causation and benefits.

As applied here, this means that LSEs in MISO’s northern and central zones should share the costs associated with the DOE Order on a load ratio share basis. The 202(c) Cost Recovery Mechanism set forth in Attachment A is designed to accomplish this outcome.

2. No MISO Tariff Provision Presently Would Permit Such Allocation and Recovery

Currently, there is no MISO Tariff provision that would permit Consumers Energy’s costs of complying with the DOE Order to be allocated to LSEs in MISO’s northern and central zones, which, if unaddressed, would effectively prevent Consumers Energy from recovering its costs via FPA section 202(c) even though, as discussed above, that statute, as well as DOE regulations and the DOE Order, all provide for full cost recovery. While full cost recovery is clearly contemplated, there is no MISO provision in the MISO Tariff that would allow Consumers Energy to recover costs associated with the DOE Order, Consumers Energy has no authority to bill anyone in MISO for such costs, and MISO cannot unilaterally offer Consumers Energy a section 202(c) rate agreement. Therefore, in order for Consumers Energy to have a means of recovering the costs that it has a right to recover, the MISO Tariff must be amended to include an appropriate recovery mechanism.

C. The Commission Has Authority Pursuant to FPA Section 309 to Require Revisions to the MISO Tariff to Implement the DOE Order

FPA section 309 authorizes the Commission “to perform any and all acts . . . as it may find necessary or appropriate to carry out the provisions of [the FPA].”⁴⁸ Courts have made clear that the Commission has significant authority under section 309 when employed to give effect to other

⁴⁸ *Id.*

substantive authority under the Act.⁴⁹ Here, the Commission’s underlying substantive authority is clearly provided by section 202(c). Because section 202(c) makes the Commission responsible for ensuring just and reasonable compensation for emergency generation or service, and because the MISO Tariff does not presently have a mechanism for addressing the Company’s Order Costs, the Commission should order MISO to implement the 202(c) Cost Recovery Mechanism the Company has included in Attachment A. This requested relief falls squarely within the Commission’s broad implementation authority under FPA section 309 and is “necessary . . . to carry out the provisions of”⁵⁰ FPA section 202(c).

V. ALTERNATIVE REQUEST FOR RELIEF PURSUANT TO FPA SECTION 206

The Company believes that FPA sections 202(c) and 309 provide ample authority for the Commission to grant the relief requested herein. Nonetheless, if the Commission finds it must invoke its FPA section 206 authority to grant the relief requested herein, Consumers Energy moves for relief under section 206 in the alternative. Under section 206, the Commission could make the requested Tariff revision effective as of the date of this Complaint.

“Section 206 permits, indeed requires, the Commission to determine whether an existing rate is ‘unjust, unreasonable, unduly discriminatory, or preferential.’”⁵¹ This statutory mandate includes determining whether a rate is unjust and unreasonable *as applied* to certain parties or to certain circumstances.⁵² Upon reaching a determination that an existing rate is unjust and

⁴⁹ *TNA Merchant Projects, Inc. v. FERC*, 857 F.3d 354, 359 (D.C. Cir. 2017); *Verso Corp. v. FERC*, 898 F.3d 1, 11-12 (D.C. Cir. 2018); *Xcel Energy Servs. Inc. v. FERC*, 815 F.3d 947 (D.C. Cir. 2016).

⁵⁰ 16 U.S.C. § 825h.

⁵¹ *Emera Me. v. FERC*, 854 F.3d 9, 21 (D.C. Cir. 2017) (quoting 16 U.S.C. § 824e(a)) (alteration incorporated).

⁵² *See, e.g., See, e.g., Pub. Serv. Elec. & Gas Co. v. FERC*, 989 F.3d 10, 18 (D.C. Cir. 2021) (“[T]he Commission reasonably found that the solution-based DFAX method was unjust and unreasonable as applied to the Artificial Island Project.”); *Am. Wind Energy Ass’n v. Sw. Power Pool, Inc.*, 167 FERC ¶

unreasonable, section 206 mandates that the Commission “determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order.”⁵³

As explained above, the Secretary of Energy has 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,” and 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).”⁵⁴ Consumers Energy will incur costs associated with the DOE Order, but the MISO Tariff does not presently include a mechanism that would allow MISO to compensate Consumers Energy for such costs or allocate those costs to load in the MISO region.

The MISO Tariff is thus unjust and unreasonable as applied to Consumers Energy and its compliance with the DOE Order, and the Commission should order MISO to adopt a Tariff revision to provide a cost recovery mechanism for Consumers Energy’s Order Costs net of market revenues. Should the Commission proceed under FPA section 206, however, Consumers Energy respectfully notes that the refund effective date that the Commission establishes pursuant to FPA section 206(b) has no bearing on, and does not limit, Consumers Energy’s right to recover the Order Costs it has already incurred and will continue to incur going forward.

61,033 at P 49 (2019) (“We find that SPP’s membership exit fee, as applied to non-transmission owners, is unjust and unreasonable because it creates a barrier to SPP membership for non-transmission owners and because it appears to be excessive based on the record before us.”), *order denying stay*, 168 FERC ¶ 61,006 (2019); *PJM Interconnection, L.L.C.*, 169 FERC ¶ 61,049 at P 138 (2019) (opening an FPA section 206 proceeding to, *inter alia*, examine “the justness and reasonableness of PJM’s minimum run-time requirements as applied to Capacity Storage Resources”); *PJM Interconnection, L.L.C.*, 137 FERC ¶ 61,145 at P 99 (2011) (“[T]he ultimate vehicle that will be required to establish that mitigation rules are unjust and unreasonable as applied to a particular project is a section 206 complaint.”) (subsequent history omitted).

⁵³ 16 U.S.C. § 824e(a).

⁵⁴ DOE Order at 1, 2.

VI. REQUEST FOR FAST TRACK PROCESSING AND EXPEDITED ACTION

Consumers Energy respectfully requests Fast Track processing and expedited action on this Complaint under Rule 206(h) of the Commission's Rules of Practice and Procedure. The Complaint merits expeditious resolution because Consumers Energy must establish a cost recovery mechanism for the costs that have been incurred, and are continuing to be incurred, to comply with the DOE Order. Expeditious action from the Commission to modify the MISO Tariff is appropriate in order to avoid challenges to Consumers Energy's right to cost recovery.

Consumers Energy respectfully requests that the Commission issue its ruling on the Complaint as soon as possible. Consumers Energy also respectfully requests a shortened comment period of ten days.

VII. ADDITIONAL INFORMATION REQUIRED BY RULE 206 OF THE COMMISSION'S RULES OF PROCEDURE

To the extent not already provided herein, the Company provides the following additional information required by Rule 206(b) of the Commission's Rules of Practice and Procedure:

- 1. Clearly identify the action or inaction which is alleged to violate applicable statutory standards or regulatory requirements; explain how the action or inaction violates applicable statutory standards or regulatory requirements.**

Despite Consumers Energy's right to recover costs incurred associated with the DOE Order, the MISO Tariff does not presently include a mechanism for the recovery and allocation of such costs, and MISO lacks Tariff authority to unilaterally offer Consumers Energy a section 202(c) rate agreement. The Commission should therefore require MISO to revise the MISO Tariff to include the proposed 202(c) Cost Recovery Mechanism.

- 2. Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the complainant.**

The information in Sections I through V of this Complaint sets forth the business, commercial, and economic issues at stake for the Company.

- 3. Make a good faith effort to quantify the financial impact or burden (if any) created for the complainant as a result of the action or inaction.**

Consumers Energy has established a regulatory asset to track all costs of operating the Campbell Plant from the date of the DOE Order. The total of such costs, net of market revenues, is not presently known. After the DOE Order expires, any costs that Consumers Energy seeks to recover through the 202(c) Cost Recovery Mechanism will be addressed in a future filing with the Commission.

- 4. Indicate the practical, operational, or other nonfinancial impacts imposed as a result of the action or inaction, including, where applicable, the environmental, safety or reliability impacts of the action or inaction.**

The DOE Order concludes that it is in the public interest for the Company to ensure that the Campbell Plant is “available to operate” in order to address the emergency conditions identified by the Secretary. The Company has a constitutional and statutory right to recover costs associated with the DOE Order. Failure of the Commission to provide the relief requested herein would conflict with the DOE Order and create unfair and unwarranted risk for the Company’s right to cost recovery.

- 5. State whether the issues presented are pending in an existing Commission proceeding or a proceeding in any other forum in which the complainant is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum.**

The issues raised in this Complaint are not pending in an existing Commission proceeding or a proceeding in any other forum in which Consumers Energy is a party. Resolution of these issues cannot be achieved in any pending docket.

6. **State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief.**

The specific relief requested is identified in Sections I and III of this Complaint.

7. **Include all documents that support the facts in the complaint in possession of, or otherwise attainable by, the complainant, including, but not limited to, contracts and affidavits.**

The only relevant document is the DOE Order, which is attached as Attachment C.

8. **State (i) whether the Enforcement Hotline, Dispute Resolution Service, tariff-based dispute resolution mechanisms, or other informal dispute resolution procedures were used, or why these procedures were not used; (ii) whether the complainant believes that alternative dispute resolution (ADR) under the Commission's supervision could successfully resolve the complaint; (iii) what types of ADR procedures could be used; and (iv) Any process that has been agreed on for resolving the complaint.**

As discussed above, Consumers Energy and MISO have cooperated extensively to evaluate and implement their respective responsibilities pursuant to the DOE Order. However, the MISO Tariff does not include a mechanism for the Company to recover costs associated with the DOE Order, and MISO does not possess unilateral authority to offer the Company a 202(c) rate agreement. Therefore, Consumers Energy believes Commission action on this Complaint is required in order to effectuate the relief requested.

9. **Include a form of notice of the complaint suitable for publication in the *Federal Register* in accordance with the specifications in § 385.203(d) of this part. The form of notice shall be on electronic media as specified by the Secretary.**

A form of notice suitable for publication in the *Federal Register* is attached to this Complaint as Attachment B.

- 10. Any person filing a complaint must serve a copy of the complaint on the respondent, affected regulatory agencies, and others the complainant reasonably knows may be expected to be affected by the complaint. Service must be simultaneous with filing at the Commission for respondents. Simultaneous or overnight service is permissible for other affected entities. Simultaneous service can be accomplished by electronic mail in accordance with § 385.2010(f)(3), facsimile, express delivery, or messenger.**

A copy of this Complaint has been served on the following via email:

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Fax: 317-249-5912
Email: jkrouse@misoenergy.org

VIII. CORRESPONDENCE AND COMMUNICATIONS

All correspondence and communications regarding this Complaint should be addressed to the following persons:⁵⁵

⁵⁵ To the extent necessary, Consumers Energy respectfully requests waiver of Rule 203(b)(3) of the Commission's Rules of Practice and Procedure to permit all of the following representatives to be placed on the official service list for this proceeding.

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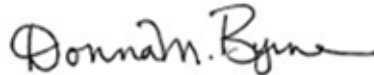
IX. CONCLUSION

For the reasons discussed above, Consumers Energy respectfully requests that the Commission swiftly issue an order granting the Complaint.

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Counsel to Consumers Energy

Attachment A

MISO
FERC Electric Tariff
SCHEDULES

SCHEDULE {XYZ}
Allocation of Costs Associated with DOE Order No. 202-25-3
{00.0.0}

SCHEDULE {XYZ}

Allocation of Costs Associated with Continued Availability of J.H. Campbell Plant Pursuant to DOE Order No. 202-25-3

On May 23, 2025, the U.S. Secretary of Energy (“Secretary”) issued an order pursuant to section 202(c) of the Federal Power Act (“FPA”), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), determining 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 (“202(c) Emergency”). *See* Department of Energy, Order No. 202-25-3 (“DOE Order”). The DOE Order compelled MISO and Consumers Energy to ensure the continued operation and availability of the 1,560 MW J.H. Campbell coal-fired power plant (“Campbell Plant”) from May 23, 2025, through August 21, 2025 (the “Order Duration Period”).

The Secretary ordered MISO and Consumers Energy to take all measures necessary to ensure that the Campbell Plant is available to operate during the Order Duration Period. The DOE Order also orders MISO to “take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers.” The DOE Order confirms that rate recovery is available pursuant to FPA section 202(c).

Costs associated with the DOE Order have been incurred, and will continue to be incurred, during the Order Duration Period (“Order Costs”). Consumers Energy (on its own behalf and, as necessary, on behalf of the minority interest owners in Campbell Unit 3, Wolverine Power Supply

Cooperative, Inc. and the Michigan Public Power Agency) shall petition FERC to approve recovery of Order Costs, net of market revenues, that FERC determines are recoverable pursuant to section 202(c) (“Recoverable Order Costs”).

This Schedule {XYZ} shall allocate the Recoverable Order Costs incurred during the Order Duration Period, and any extensions of the same by the Secretary, in the following manner. MISO shall allocate the Recoverable Order Costs to LSEs in the Zones 1-7 (or such successor zone designations reflecting the Northern and Central MISO Zones) (“Affected LSEs”) on a load ratio share basis.

The charge to each Affected LSE (AFF_LSE_CHG) is obtained by multiplying Affected LSE load ratio share (AFF_LSE_SHARE) by the Recoverable Order Costs (REC_EMERG_ORDER_COSTS):

$$\text{AFF_LSE_CHG} = \text{AFF_LSE_SHARE} \times \text{REC_EMERG_ORDER_COSTS}$$

Effective On: {DATE}

Attachment B

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

NOTICE OF COMPLAINT

(_____)

Take notice that on June 6, 2025, Consumers Energy Company (“Consumers Energy”) filed a complaint (“Complaint”) against Midcontinent Independent System Operator, Inc. (“MISO”) pursuant to sections 202(c), 306, and 309 of the Federal Power Act (“FPA”)¹ and Rule 206 of the Federal Energy Regulatory Commission’s (“FERC” or “Commission”) Rules of Practice and Procedure.² Consumers Energy requests the Commission direct MISO to revise its Open Access Transmission, Energy and Operating Reserve Markets Tariff to effectuate an emergency order issued by the Secretary of Energy on May 23, 2025, pursuant to FPA section 202(c).³

Consumers Energy certifies that a copy of the Complaint was served on representatives of MISO.

Any person desiring to intervene or protest this filing must file in accordance with Rules 211 and 214 of the Commission’s Rules of Practice and Procedure (18 C.F.R. §§ 385.211 and 214). Protests will be considered by the Commission in determining the appropriate action to be taken but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. The Respondent’s answer and all interventions or protests must be filed on or before the comment date. The Respondent’s answer, motions to intervene, and protests must be served on the Complainant.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the “eFiling link at <http://www.ferc.gov>. Persons unable to file electronically should submit an original and five (5) copies of the protest to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426.

¹ 16 U.S.C. §§ 824e, 825e, 825h.

² 18 C.F.R. § 385.206 (2024).

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

This filing is accessible online at <http://www.ferc.gov>, using the “eLibrary” link and is available for review in the Commission’s Public Reference Room in Washington, DC. There is an “eSubscription” link on the website that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please email FERCOnlineSupport@ferc.gov, or call (866) 208-3676 (toll-free). For TTY, call (202) 502-8659.

Comment Date: 5:00 pm Eastern Time on (_____).

Debbie-Anne A. Reese
Secretary

Attachment C

Order No. 202-25-3

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

Emergency Situation

The Midcontinent Independent System Operator (MISO) faces potential tight reserve margins during the summer 2025 period, particularly during periods of high demand or low generation resource output. The North American Electric Reliability Corporation (NERC) released its 2025 Summer Reliability Assessment on May 14, 2025. In its assessment, NERC indicated that “[d]emand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output.”¹ In particular, the retirement of thermal generation capacity creates the potential for electricity supply shortfalls. NERC anticipates that the near-term period of highest capacity shortfall for MISO will occur in August.²

Multiple generation facilities in Michigan have retired in recent years. According to the U.S. Energy Information Administration (EIA), “[s]ince 2020, about 2,700 megawatts of coal-fired generating capacity have been retired and no new coal-fired facilities are planned.”³ Additionally EIA stated, “[t]ypically Michigan’s nuclear power plants have supplied about 30% of in-state electricity, but the amount of electricity generated by nuclear power plants in Michigan has declined as plants have been decommissioned.”⁴ The state’s Big Rock Point nuclear power plant shut down in 1997 and the Palisades nuclear power plant closed in 2022. While the Palisades nuclear power plant may reopen in 2025, it will not be available during the peak demand period this summer.

The 1,560 MW J.H. Campbell coal-fired power plant in West Olive, MI, is scheduled to cease operations on May 31, 2025. Its retirement would further decrease available dispatchable generation within MISO’s service territory, removing additional such generation along with the other 1,575 MW of natural gas and coal-fired generation that has retired since the summer of 2024. In 2021, Consumers announced that it planned to “speed closure” of Campbell in 2025, several years before the end of its scheduled design life.⁵ Although MISO and Consumers have

¹ 2025 summer reliability assessment. (May 14, 2025).

https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf

² *Id.*

³ U.S. Energy Information Administration, Michigan State Energy Profile, Oct. 17, 2024, *available at*: <https://www.eia.gov/state/print.php?sid=mi>.

⁴ *Id.*

⁵ <https://www.consumersenergy.com/news-releases/news-release-details/2021/06/23/consumers-energy-announces-plan-to-end-coal-use-by-2025-lead-michigans-clean-energy-transformation>

incorporated the planned retirement into their supply forecasts and acquired a 1,200 MW natural gas power plant in Covert, MI, the NERC Assessment still anticipates “elevated risk of operating reserve shortfalls.”

MISO’s Planning Resource Auction Results for Planning Year 2025-26, released in April 2025, note that for the northern and central zones, which includes Michigan, “new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources.” While the results “demonstrated sufficient capacity,” the summer months reflected the “highest risk and a tighter supply-demand balance” and the results “reinforce the need to increase capacity.”⁶

ORDER

Given the determination that an emergency exists as discussed above, the responsibility of MISO to ensure reliability of its system, and the ability of MISO to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, 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). This determination is based on the insufficiency of dispatchable capacity and anticipated demand during the summer months, and the potential loss of power to homes and local businesses in the areas that may be affected by curtailments or outages, presenting a risk to public health and safety.

This Order is limited in duration to align with the emergency circumstances. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation on the conditions contained in this Order, with reporting requirements as described below.

FPA section 202(c) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the “hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable,” be consistent with any applicable environmental law and minimize any adverse environmental impacts.

Based on my determination of an emergency set forth above, I hereby order:

- A. From the time this Order is issued on May 23, 2025, MISO and Consumers Energy shall take all measures necessary to ensure that the Campbell Plant is available to operate. For the duration of this order, MISO is directed to take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers. Following conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Consumers Energy is directed to comply with all orders from MISO related to the availability and dispatch of the Campbell Plant.

⁶ <https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250428694160.pdf>

- B. To minimize adverse environmental impacts, this Order limits operation of dispatched units through the expiration of the Order. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Campbell Plant has operated in compliance with the allowances contained in this Order.
- C. All operation of the Campbell Plant must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.
- D. By June 15, 2025, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability and economic dispatch of the Campbell Plant consistent with the public interest. MISO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.
- E. The 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.
- F. Consumers is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers necessary to effectuate this order. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).
- G. This Order shall not preclude the need for the Campbell Plant to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.
- H. This Order shall be effective upon its issuance, and shall expire at 00:00 EDT on August 21, 2025, with the exception of the reporting requirements in paragraph D and applicable compliance obligations in paragraph E.
- I. Issued in Washington, D.C. at 3:15:pm Eastern Daylight Time on this 23rd day of May 2025.



Chris Wright
Secretary of Energy

cc: **FERC Commissioners**

Chairman Mark Christie
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang

Michigan Public Service Commissioners

Chairman Dan Cripps
Commissioner Katherine Peretick
Commissioner Alessandra Carreon

Attachment Y

MISO, Grid Conditions Explainer



Grid Conditions At a Glance

The grid conditions gauge is a visual representation of MISO's active market capacity emergency notifications. The tool, designed for situational awareness only, shows real-time generation (capacity) and/or weather conditions impacting the MISO grid. The gauge needle moves when an alert, advisory, warning, event, or termination instruction takes effect (not when a notification is sent).

Disclaimer: MISO notifications are official communications authored by the control room shift manager. The notification takes precedence over what may be shared visually on the Grid Conditions gauge.



Grid Conditions Normal

Green

Under normal grid conditions, the needle points to the green section of the gauge signifying the grid is stable.

Should operators issue a weather related alert, e.g. Severe Weather Alert, the needle remains in the green. However, a "View Notification" button will appear under the gauge. By clicking on the button, users can read the alert issued by the control room shift manager. The alert includes information on the affected MISO region and expected weather conditions.

All MISO notifications are operator-to-operator communications.



Grid Advisories/Warnings Issued

Grid Stable

[View Notification](#)

Yellow

The grid is stable and MISO has issued one or more of the following notifications:

Conservative Operations: Used for situational awareness, the conservative operations notification asks MISO members to defer, delay, or recall any non-essential maintenance. This notification provides MISO member operators an indication that system conditions *may* require special attention.

Capacity Advisory: Used for situational awareness, this notification informs MISO member operators that, based on projected system conditions and capacity (supply) levels, there *may* be a need in the coming days to bring additional generation on-line.

Maximum Generation Alert: Used for situational awareness, this notification serves as an early alert that system conditions *may* require emergency actions.

Maximum Generation Warning: This notification asks member operators to prepare for a *possible* situation (an energy emergency alert) where operating reserve requirements may not be met without taking actions.



Energy Emergency Alert 1 (EEA1)

Power demand could exceed available supply
Grid Stable

[View Notification](#)

Orange

The grid is stable and MISO has issued an Energy Emergency Alert 1 (EEA1).

EEA1 is the first level of emergency action, triggered when MISO can no longer meet the forecasted demand and operating reserve requirements without intervention. In other words, it indicates that power demand may exceed supply if no action is taken.

By declaring EEA1, MISO operators can access additional generation to boost the electricity supply and maintain grid reliability.



Energy Emergency Alert 2 (EEA2)

Emergency power and/or reduced demand necessary

[View Notification](#)

Dark Orange

The grid is stable and MISO has issued an Energy Emergency Alert 2 (EEA2).

EEA2 is the second level of emergency action, triggered as operating reserves continue to decline. It means MISO is facing an energy shortage and needs to reduce energy demand.

By declaring EEA2, MISO operators can access emergency generation not available under normal conditions. They may also purchase emergency energy from neighboring grids (if available) and implement measures to reduce electricity demand. One option is for MISO to ask member utilities to encourage consumers to conserve power. However, an EEA2 declaration does not automatically mean this step will be taken.



Energy Emergency Alert 3 (EEA3)

Power interruptions imminent or happening

[View Notification](#)

Red

MISO has issued an Energy Emergency Alert 3 (EEA3).

EEA3 is the final level of emergency action, triggered to prevent cascading outages and ensure grid reliability for as many consumers as possible. It indicates that energy supply and demand are unbalanced, and power interruptions are imminent or already occurring.

Power interruptions are a last resort to protect the grid's stability. In these rare situations, MISO's role is to identify the areas where interruptions are needed and determine how much electricity must be reduced to balance supply and demand. MISO's member utilities are responsible for carrying out the interruptions and deciding which customers will temporarily lose power.



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Attachment Z

NERC, Attachment 1-EOP-011-1 Energy Emergency Alerts.

A. Introduction

1. **Title:** Emergency Operations
2. **Number:** EOP-011-1
3. **Purpose:** To address the effects of operating Emergencies by ensuring each Transmission Operator and Balancing Authority has developed Operating Plan(s) to mitigate operating Emergencies, and that those plans are coordinated within a Reliability Coordinator Area.
4. **Applicability:**
 - 4.1. **Functional Entities:**
 - 4.1.1 Balancing Authority
 - 4.1.2 Reliability Coordinator
 - 4.1.3 Transmission Operator
5. **Effective Date:**

See *Implementation Plan for EOP-011-1*
6. **Background:**

EOP-011-1 consolidates requirements from three standards: EOP-001-2.1b, EOP-002-3.1, and EOP-003-2.

The standard streamlines the requirements for Emergency operations for the Bulk Electric System into a clear and concise standard that is organized by Functional Entity. In addition, the revisions clarify the critical requirements for Emergency Operations, while ensuring strong communication and coordination across the Functional Entities.

B. Requirements and Measures

- R1. Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*
 - 1.1. Roles and responsibilities for activating the Operating Plan(s);
 - 1.2. Processes to prepare for and mitigate Emergencies including:
 - 1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency;
 - 1.2.2. Cancellation or recall of Transmission and generation outages;
 - 1.2.3. Transmission system reconfiguration;
 - 1.2.4. Redispatch of generation request;

- M2.** Each Balancing Authority will have a dated Operating Plan(s) developed in accordance with Requirement R2 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R2.
- R3.** The Reliability Coordinator shall review the Operating Plan(s) to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority regarding any reliability risks that are identified between Operating Plans. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- 3.1.** Within 30 calendar days of receipt, the Reliability Coordinator shall:
- 3.1.1.** Review each submitted Operating Plan(s) on the basis of compatibility and inter-dependency with other Balancing Authorities' and Transmission Operators' Operating Plans;
 - 3.1.2.** Review each submitted Operating Plan(s) for coordination to avoid risk to Wide Area reliability; and
 - 3.1.3.** Notify each Balancing Authority and Transmission Operator of the results of its review, specifying any time frame for resubmittal of its Operating Plan(s) if revisions are identified.
- M3.** The Reliability Coordinator will have documentation, such as dated e-mails or other correspondences that it reviewed Transmission Operator and Balancing Authority Operating Plans within 30 calendar days of submittal in accordance with Requirement R3.
- R4.** Each Transmission Operator and Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to Requirement R3 and resubmit its Operating Plan(s) to its Reliability Coordinator within a time period specified by its Reliability Coordinator. *[Violation Risk Factor: High] [Time Horizon: Operation Planning]*
- M4.** The Transmission Operator and Balancing Authority will have documentation, such as dated emails or other correspondence, with an Operating Plan(s) version history showing that it responded and updated the Operating Plan(s) within the timeframe identified by its Reliability Coordinator in accordance with Requirement R4.
- R5.** Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area shall notify, within 30 minutes from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

EOP-011-1 Emergency Operations

- M5.** Each Reliability Coordinator that receives an Emergency notification from a Balancing Authority or Transmission Operator within its Reliability Coordinator Area will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that will be used to determine if the Reliability Coordinator communicated, in accordance with Requirement R5, with other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators .
- R6.** Each Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall declare an Energy Emergency Alert, as detailed in Attachment 1. [*Violation Risk Factor: High*]
[*Time Horizon: Real-Time Operations*]
- M6.** Each Reliability Coordinator, with a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area, will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that it declared an Energy Emergency Alert, as detailed in Attachment 1, in accordance with Requirement R6.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” (CEA) 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 Balancing Authority, Reliability Coordinator, and Transmission Operator shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Transmission Operator shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R1 and R4 and Measures M1 and M4.
- The Balancing Authority shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R2 and R4, and Measures M2 and M4.
- The Reliability Coordinator shall maintain evidence of compliance since the last audit for Requirements R3, R5, and R6 and Measures M3, M5, and M6.

If a Balancing Authority, Reliability Coordinator or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

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:

As defined in the NERC Rules of Procedure; “Compliance Monitoring and Assessment Processes” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Real-time Operations, Operations Planning, Long-term Planning	High		The Transmission Operator developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area but failed to maintain it.	The Transmission Operator developed an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area but failed to have it reviewed by its Reliability Coordinator.	The Transmission Operator failed to develop an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. OR The Transmission Operator developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area but failed to implement it.

EOP-011-1 Emergency Operations

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Real-time Operations, Operations Planning, Long-term Planning	High	N/A	The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area but failed to maintain it.	The Balancing Authority developed an Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area but failed to have it reviewed by its Reliability Coordinator.	The Balancing Authority failed to develop an Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area. OR The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area but failed to implement it.

EOP-011-1 Emergency Operations

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Operations Planning	High	N/A	N/A	The Reliability Coordinator identified a reliability risk but failed to notify the Balancing Authority or Transmission Operator within 30 calendar days.	The Reliability Coordinator identified a reliability risk but failed to notify the Balancing Authority or Transmission Operator.
R4	Operations Planning	High	N/A	N/A	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator within the timeframe specified by its Reliability Coordinator.	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator.
R5	Real-time Operations	High	N/A	N/A	The Reliability Coordinator that received an Emergency	The Reliability Coordinator that received an Emergency

EOP-011-1 Emergency Operations

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					notification from a Transmission Operator or Balancing Authority did notify neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators but failed to notify within 30 minutes from the time of receiving notification.	notification from a Transmission Operator or Balancing Authority failed to notify neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators.
R6	Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to declare an Energy Emergency Alert.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	November 13, 2014	Adopted by Board of Trustees	Merged EOP-001-2.1b, EOP-002-3.1 and EOP-003-2.
1	November 19, 2015	FERC approved EOP-011-1. Docket Nos. RM15-7-000, RM15-12-000, and RM15-13-000. Order No. 818	

Attachment 1-EOP-011-1 Energy Emergency Alerts

Introduction

This Attachment provides the process and descriptions of the levels used by the Reliability Coordinator in which it communicates the condition of a Balancing Authority which is experiencing an Energy Emergency.

A. General Responsibilities

- 1. Initiation by Reliability Coordinator.** An Energy Emergency Alert (EEA) may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of an energy deficient Balancing Authority.
- 2. Notification.** A Reliability Coordinator who declares an EEA shall notify all Balancing Authorities and Transmission Operators in its Reliability Coordinator Area. The Reliability Coordinator shall also notify all neighboring Reliability Coordinators.

B. EEA Levels

Introduction

To ensure that all Reliability Coordinators clearly understand potential and actual Energy Emergencies in the Interconnection, NERC has established three levels of EEAs. The Reliability Coordinators will use these terms when communicating Energy Emergencies to each other. An EEA is an Emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC Reliability Standards.

The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.

1. EEA 1 — All available generation resources in use.

Circumstances:

- The Balancing Authority is experiencing conditions where all available generation resources are committed to meet firm Load, firm transactions, and reserve commitments, and is concerned about sustaining its required Contingency Reserves.
- Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

2. EEA 2 — Load management procedures in effect.

Circumstances:

- The Balancing Authority is no longer able to provide its expected energy requirements and is an energy deficient Balancing Authority.
- An energy deficient Balancing Authority has implemented its Operating Plan(s) to mitigate Emergencies.

- An energy deficient Balancing Authority is still able to maintain minimum Contingency Reserve requirements.

During EEA 2, Reliability Coordinators and energy deficient Balancing Authorities have the following responsibilities:

2.1 Notifying other Balancing Authorities and market participants. The energy deficient Balancing Authority shall communicate its needs to other Balancing Authorities and market participants. Upon request from the energy deficient Balancing Authority, the respective Reliability Coordinator shall post the declaration of the alert level, along with the name of the energy deficient Balancing Authority on the RCIS website.

2.2 Declaration period. The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 2 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators.

2.3 Sharing information on resource availability. Other Reliability Coordinators of Balancing Authorities with available resources shall coordinate, as appropriate, with the Reliability Coordinator that has an energy deficient Balancing Authority.

2.4 Evaluating and mitigating Transmission limitations. The Reliability Coordinator shall review Transmission outages and work with the Transmission Operator(s) to see if it's possible to return to service any Transmission Elements that may relieve the loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).

2.5 Requesting Balancing Authority actions. Before requesting an EEA 3, the energy deficient Balancing Authority must make use of all available resources; this includes, but is not limited to:

2.5.1 All available generation units are on line. All generation capable of being on line in the time frame of the Emergency is on line.

2.5.2 Demand-Side Management. Activate Demand-Side Management within provisions of any applicable agreements.

3. EEA 3 — Firm Load interruption is imminent or in progress.

Circumstances:

- The energy deficient Balancing Authority is unable to meet minimum Contingency Reserve requirements.

During EEA 3, Reliability Coordinators and Balancing Authorities have the following responsibilities:

3.1 Continue actions from EEA 2. The Reliability Coordinators and the energy deficient Balancing Authority shall continue to take all actions initiated during EEA 2.

3.2 Declaration Period. The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 3 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities, and Transmission Operators.

3.3 Reevaluating and revising SOLs and IROLs. The Reliability Coordinator shall evaluate the risks of revising SOLs and IROLs for the possibility of delivery of energy to the energy deficient Balancing Authority. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Transmission Operator whose Transmission Owner (TO) equipment would be affected. SOLs and IROLs shall only be revised as long as an EEA 3 condition exists, or as allowed by the Transmission Owner whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:

3.3.1 Energy deficient Balancing Authority obligations. The energy deficient Balancing Authority, upon notification from its Reliability Coordinator of the situation, it will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include Load shedding.

3.4 Returning to pre-Emergency conditions. Whenever energy is made available to an energy deficient Balancing Authority such that the Systems can be returned to its pre-Emergency SOLs or IROLs condition, the energy deficient Balancing Authority shall request the Reliability Coordinator to downgrade the alert level.

3.4.1 Notification of other parties. Upon notification from the energy deficient Balancing Authority that an alert has been downgraded, the Reliability Coordinator shall notify the neighboring Reliability Coordinators (via the RCIS), Balancing Authorities and Transmission Operators that its Systems can be returned to its normal limits.

Alert 0 - Termination. When the energy deficient Balancing Authority is able to meet its Load and Operating Reserve requirements, it shall request its Reliability Coordinator to terminate the EEA.

0.1 Notification. The Reliability Coordinator shall notify all other Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the neighboring Balancing Authorities and Transmission Operators.

Guidelines and Technical Basis

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:

The EOP SDT examined the recommendation of the EOP Five-Year Review Team (FYRT) and FERC directive to provide guidance on applicable entity responsibility that was included in EOP-001-2.1b. The EOP SDT removed EOP-001-2.1b, Attachment 1, and incorporated it into this standard under the applicable requirements. This also establishes a separate requirement for the Transmission Operator to create an Operating Plan(s) for mitigating operating Emergencies in its Transmission Operator Area.

The Operating Plan(s) can be one plan, or it can be multiple plans.

“Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency” was retained. This is a process in the plan(s) that determines when the Transmission Operator must notify its Reliability Coordinator.

To meet the associated measure, an entity would likely provide evidence that such an evaluation was conducted along with an explanation of why any overlap of Loads between manual and automatic load shedding was unavoidable or reasonable.

An Operating Plan(s) is implemented by carrying out its stated actions.

If any Parts of Requirement R1 are not applicable, the Transmission Operator should note “not applicable” in the Operating Plan(s). The EOP SDT recognizes that across the regions, Operating Plan(s) may not include all the elements listed in this requirement due to restrictions, other methods of managing situations, and documents that may already exist that speak to a process that already exists. Therefore, the entity must provide in the plan(s) that the element is not applicable and detail why it is not applicable for the plan(s).

With respect to automatic Load shedding schemes that include both UVLS and UFLS, the EOP SDT’s intent is to keep manual and automatic Load shed schemes as separate as possible, but realizes that sometimes, due to system design, there will be overlap. The intent in Requirement R1 Part 1.2.5. is to minimize, as much as possible, the use of manual Load shedding which is already armed for automatic Load shedding. The automatic Load shedding schemes are the important backstops against Cascading outages or System collapse. If any entity manually sheds a Load which was included in an automatic scheme, it reduces the effectiveness of that automatic scheme. Each entity should review their automatic Load shedding schemes and coordinate their manual processes so that any overlapping use of Loads is avoided to the extent reasonably possible.

Application Guidelines

Rationale for R2:

To address the recommendation of the FYRT and the FERC directive to provide guidance on applicable entity responsibility in EOP-001-2.1b, Attachment 1, the EOP SDT removed EOP-001-2.1b, Attachment 1, and incorporated it into this standard under the applicable requirements. EOP-011-1 also establishes a separate requirement for the Balancing Authority to create its Operating Plan(s) to address Capacity and Energy Emergencies.

The Operating Plan(s) can be one plan, or it can be multiple plans.

An Operating Plan(s) is implemented by carrying out its stated actions.

If any Parts of Requirement R2 are not applicable, the Balancing Authority should note “not applicable” in the Operating Plan(s). The EOP SDT recognizes that across the regions, Operating Plan(s) may not include all the elements listed in this requirement due to restrictions, other methods of managing situations, and documents that may already exist that speak to a process that already exists. Therefore, the entity must provide in the plan(s) that the element is not applicable and detail why it is not applicable for the plan(s).

The EOP SDT retained the statement “Operator-controlled manual Load shedding,” as it was in the current EOP-003-2 and is consistent with the intent of the EOP SDT.

With respect to automatic Load shedding schemes that include both UVLS and UFLS, the EOP SDT’s intent is to keep manual and automatic Load shedding schemes as separate as possible, but realizes that sometimes, due to system design, there will be overlap. The intent in Requirement R2 Part 2.2.8. is to minimize as much as possible the use manual Load shedding which is already armed for automatic Load shedding. The automatic Load shedding schemes are the important backstops against Cascading outages or System collapse. If an entity manually sheds a Load that was included in an automatic scheme, it reduces the effectiveness of that automatic scheme. Each entity should review its automatic Load shedding schemes and coordinate its manual processes so that any overlapping use of Loads is avoided to the extent possible.

The EOP SDT retained Requirement R8 from EOP-002-3.1 and added it to the Parts in Requirement R2.

Rationale for R3:

The SDT agreed with industry comments that the Reliability Coordinator does not need to approve BA and TOP plan(s). The SDT has changed this requirement to remove the approval but still require the RC to review each entity’s plan(s), looking specifically for reliability risks. This is consistent with the Reliability Coordinator’s role within the Functional Model and meets the FERC directive regarding the RC’s involvement in Operating Plan(s) for mitigating Emergencies.

Rationale for Requirement R4:

Requirement R4 supports the coordination of Operating Plans within a Reliability Coordinator Area in order to identify and correct any Wide Area reliability risks. The EOP SDT expects the Reliability Coordinator to make a reasonable request for response time. The time period requested by the Reliability Coordinator to the Transmission Operator and Balancing Authority to update the Operating Plan(s) will depend on the scope and urgency of the requested change.

Application Guidelines

Rationale for R5

The EOP SDT used the existing requirement in EOP-002-3.1 for the Balancing Authority and added the words “within 30 minutes from the time of receiving notification” to the requirement to communicate the intent that timeliness is important, while balancing the concern that in an Emergency there may be a need to alleviate excessive notifications on Balancing Authorities and Transmission Operators. By adding this time limitation, a measurable standard is set for when the Reliability Coordinator must complete these notifications.

Rationale for Introduction

LSEs were removed from Attachment 1, as an LSE has no Real-time reliability functionality with respect to EEAs.

EOP-002-3.1 Requirement R9 was in place to allow for a Transmission Service Provider to change the priority of a service request, as permitted in its transmission tariff, informing the Reliability Coordinator so that the service would not be curtailed by a TLR; and since the Tagging Specs did not allow profiles to be changed, this was the only method to accomplish it. Under NAESB WEQ E-tag Specification v1811 R3.6.1.3, this has been modified and now the TSP has the ability to change the Transmission priority which, in turn, is reflected in the IDC. This technology change allows for the deletion of Requirement R9 in its entirety. Requirement R9 meets with Criterion A of Paragraph 81 and should be retired.

Rationale for (2) Notification

The EOP SDT deleted the language, “*The Reliability Coordinator shall also notify all other Reliability Coordinators of the situation via the Reliability Coordinator Information System (RCIS). Additionally, conference calls between RCs shall be held as necessary to communicate system conditions. The RC shall also notify the other RCs when the alert has ended*” as duplicative to proposed IRO-014-3 Requirement R1:

- R1. Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following:
- 1.1 Communications and notifications, and the process to follow in making those notifications.
 - 1.2 Energy and capacity shortages.
 - 1.3 Control of voltage, including the coordination of reactive resources.
Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments.
 - 1.5 Authority to act to prevent and mitigate system conditions which could adversely impact other Reliability Coordinator Areas.
 - 1.6 Provisions for weekly conference calls.

Application Guidelines

Rationale for EEA 2:

The EOP SDT modified the “Circumstances” for EEA 2 to show that an entity will be in this level when it has implemented its Operating Plan(s) to mitigate Emergencies but is still able to maintain Contingency Reserves.

Rationale for EEA 3:

This rationale was added at the request of stakeholders asking for justification for moving a lack of Contingency Reserves into the EEA3 category.

The previous language in EOP-002-3.1, EEA 2 used “Operating Reserve,” which is an all-inclusive term, including all reserves (including Contingency Reserves). Many Operating Reserves are used continuously, every hour of every day. Total Operating Reserve requirements are kind of nebulous since they do not have a specific hard minimum value. Contingency Reserves are used far less frequently. Because of the confusion over this issue, evidenced by the comments received, the drafting team thought that using minimum Contingency Reserve in the language would eliminate some of the confusion. This is a different approach but the drafting team believes this is a good approach and was supported by several commenters.

Using Contingency Reserves (which is a subset of Operating Reserves) puts a BA closer to the operating edge. The drafting team felt that the point where a BA can no longer maintain this important Contingency Reserves margin is a most serious condition and puts the BA into a position where they are very close to shedding Load (“imminent or in progress”). The drafting team felt that this warrants categorization at the highest level of EEA.