BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-7

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

Filed September 5, 2025

Exhibit 81

Joundi Testimony

Tab E

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Midcontinent Independent System Operator, Inc.	**)**	**Docket No. ER24-___-000**

PREPARED DIRECT TESTIMONY OF ZAKARIA JOUNDI EXECUTIVE DIRECTOR, MARKET & GRID STRATEGY

I. PROFESSIONAL BACKGROUND AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION WITH THE MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC.

A. My name is Zakaria (Zak) Joundi. I am the Executive Director, Market & Grid Strategy for the Midcontinent Independent System Operator, Inc. (MISO). My business address is 720 City Center Drive, Carmel, Indiana 46032.

Q. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL BACKGROUND.

A. I hold a Bachelor of Science degree in electrical engineering, with an emphasis in power systems, from Iowa State University and a Master of Business Administration degree, with an emphasis in finance, from the Indiana University Kelley School of Business. I joined MISO in 2006 and have held multiple positions of increasing responsibilities that span across generation and transmission planning, market administration, seams administration, data and analytics, and resource adequacy (RA). I have also supported numerous MISO initiatives and filings with the Federal Energy Regulatory Commission (Commission), including financial transmission rights (FTR), seams, and RA matters.

Q. PLEASE DESCRIBE YOUR CURRENT ROLE AND JOB RESPONSIBILITIES.

A. In my current role as Executive Director, Market & Grid Strategy, I oversee the team responsible for the design of the MISO markets and the assessment of its performance. One of my primary responsibilities has been serving as the MISO liaison to the Resource Adequacy Subcommittee (RASC), which is the stakeholder led group at MISO focused on RA matters.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to support the resource accreditation reform proposed in this filing.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony begins with a brief discussion of MISO's current approach to resource adequacy, including the challenges with the current accreditation approach and the problem statement MISO developed with stakeholders to address those challenges. Next, I discuss MISO's proposed resource accreditation method and describe the design details associated with that approach. I then discuss MISO's approach to loss of load expectation (LOLE) modeling. From there, I describe the evaluation criteria MISO used to analyze the various options for proposed resource accreditation reforms. Finally, I discuss MISO's implementation timeline, stakeholder engagement, and other key considerations.

Q. PLEASE PROVIDE AN OVERVIEW OF MISO'S PROPOSED RESOURCE ACCREDITATION METHODOLOGY.

A. MISO's proposed resource accreditation methodology is a two-step approach that first measures a resource's expected marginal contribution to reliability using class-level performance (probabilistic approach) and then uses historical resource-level performance (deterministic approach) to accredit individual resources within the class of comparable

resources (Resource Class).[1] The proposed accreditation methodology accounts for a range of reliability risks in the planning and operations horizons by incorporating forward-looking probabilistic analysis and measuring a resource's performance during recent periods of high system risk. Under the proposal, MISO defines the periods of highest system risk identified in the probabilistic analysis as "Critical Hours". Critical Hours include all loss of load hours and, as needed, low margin hours,[2] as further described below. MISO's proposed approach to measure the availability of resources during Critical Hours in its probabilistic analysis is within the marginal Effective Load Carrying Capacity (ELCC) accreditation framework that is used by other market administrators (e.g., PJM Interconnection, L.L.C. (PJM) and New York Independent System Operator, Inc. (NYISO)).[3] MISO refers to its approach as the Direct Loss of Load (DLOL)-based methodology and proposes to use it as the single uniform method for accrediting all Capacity Resources, except External Resources (hereinafter referred to as "Schedule 53A Resources"), that currently participate in its Planning Resource Auction (PRA). In the simplest terms, the proposed two-step approach can be described as first determining the size of a pie (accreditation for an entire resource class) and then second, allocating or divvying up the pie (individual resource level accreditation) as shown in Figure 1 below.

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[1] The term "Resource Class" as used in Schedule 53A and this testimony means a group of Capacity Resources, except External Resources, with similar operating characteristics whose Resource Class-level UCAP has been determined based on the LOLE analysis and is further described in Schedule 53A.

[2] Low margin hours are comprised of those hours where available generation in excess of load is less than or equal to 3% of load in that hour (*i.e.*, low margin) up to a cap of 1,950 hours in each Season.

[3] *See PJM Interconnection, L.L.C.*, 186 FERC ¶ 61,080 (2024). *See* also *New York Indep. System Operator, Inc*., 179 FERC ¶ 61,102 (May 10, 2022).

The proposed reform is consistent with MISO's Market Design Guiding Principles. It aligns operational needs with non-discriminatory market and planning requirements, and results in transparent market prices that reflect marginal contributions to reliability during highest risk hours.

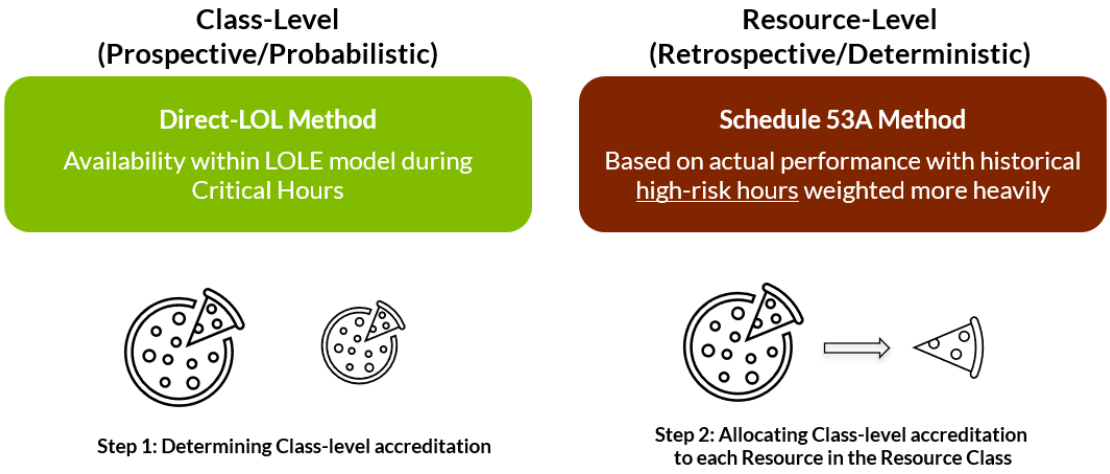

Figure 1: MISO's proposed accreditation methodology

III. OVERVIEW OF MISO'S APPROACH TO RESOURCE ADEQUACY

Q. WHAT IS RESOURCE ADEQUACY?

A. Resource adequacy refers to the ability of the bulk electric system to serve electricity demand while also providing enough excess supply to achieve a threshold level of grid reliability. One such measure of reliability is the industry-accepted Loss-of-Load Expectation (LOLE) target of one day of loss of load every ten years. Following the Commission's acceptance of MISO's Seasonal Resource Adequacy Construct and Seasonal Accredited Capacity filing in August 2022,[4] and commencing with MISO's

[4] *See Midcontinent Independent System Operator, Inc.*, 180 FERC ¶61,141 (2022).

Planning Year 2023/2024 PRA, MISO now makes such LOLE determinations on a seasonal basis, for each PRA.

Q. WHICH ENTITIES ARE RESPONSIBLE FOR ACHIEVING RESOURCE ADEQUACY IN THE MISO FOOTPRINT?

A. In the MISO footprint, the primary responsibility for achieving resource adequacy rests with Load Serving Entities (LSE) with oversight by Relevant Electric Retail Rate Authorities (RERRA), as applicable by jurisdiction. MISO facilitates these efforts by administering its Open Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff)-defined Resource Adequacy Requirements (RAR) and the PRA, which LSEs use to demonstrate their ability to serve seasonal peak demand and provide a sufficient margin of excess supply.

Q. BRIEFLY DESCRIBE THE RESOURCE ADEQUACY CHALLENGES THAT ACCOMPANY THE ONGOING TRANSFORMATION OF THE ELECTRICITY SECTOR.

A. Historically, periods of risk have been driven primarily by periods of high demand. The composition of that demand would evolve over time, but the periods of highest load were generally relatively consistent and forecastable, historically based on the Summer peak. At the same time, generation availability was largely driven by uncorrelated unit outages, which were thus assumed to be independent. Because of this relative stability, grid reliability was achieved by ensuring enough generation capacity existed to reliably serve the peak load based on a single occurrence during the year (e.g., the Summer coincident peak). In addition, frequent, large-scale weather events on the Transmission System have presented challenges to maintaining resource adequacy in the recent past.

A number of factors now require the application of a new approach for determining resource accreditation in MISO, consistent with developments in other parts of the country, to ensure reliable grid operations are maintained going forward. The transformation of the grid is accelerating, resulting in increasing reliance on newer types of generation, such as weather-dependent, highly variable wind and solar resources and energy-limited storage resources. Moreover, projected electrification is expected to increase challenges in the MISO footprint. These drivers are decoupling periods of risk from periods of high demand, upending traditional methods to establish reliability requirements and ensure resource adequacy. Figure 2.a shows how the timing of expected unserved energy[5] (in blue) for the average summer day is expected to shift and move away from times of highest load (in grey), and better align with times of highest load net of wind and solar (in red). The same information and trend is observed for an average winter day, as shown in Figure 2.b. Further, the comparison of the two figures shows how the seasonal distribution of events is expected to shift from summer to winter over the next decade.[6]

[5] The proposed Tariff definition of Expected Unserved Energy as follows: "In the probabilistic study, an estimate of the energy that would otherwise have been used by end use customers but for a supply interruption." See *Midcontinent Independent System Operator, Inc.,* Docket No. ER23-2977-000.

[6] Additional information on this analysis can be found in MISO's 2023 Attributes Roadmap.

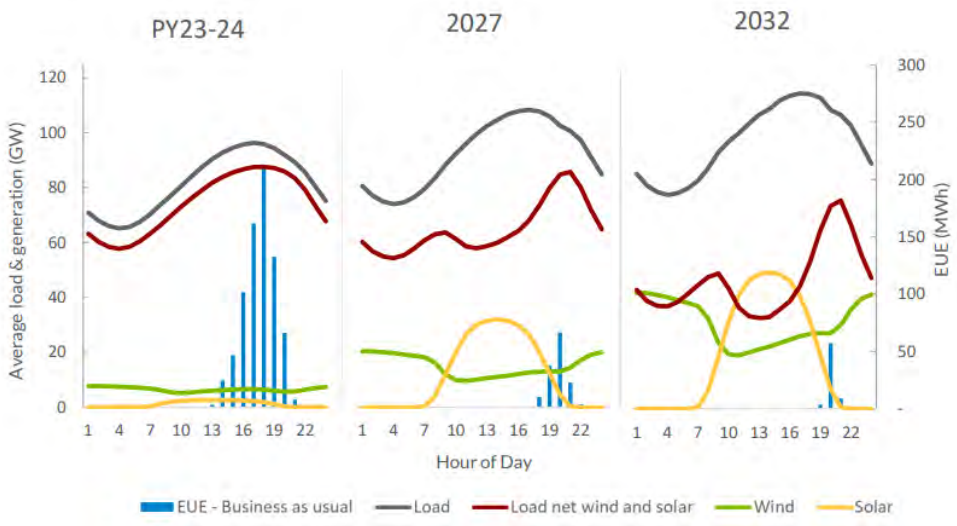

Figure 2.a. Estimated evolution of summer load, net load, wind and solar and expected unserved energy in the MISO footprint

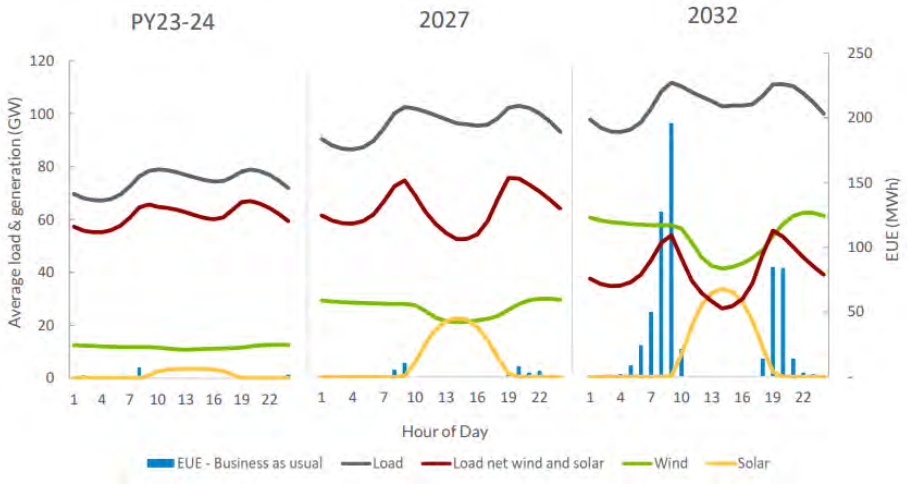

Figure 2.b. Estimated evolution of winter load, net load, wind and solar and expected unserved energy in the MISO footprint

Q. WHAT ROLE DOES ACCREDITATION PLAY IN MISO'S PRA?

A. MISO defines resource accreditation as the capacity value of a resource based on its contribution to system reliability during periods of highest risk. MISO accredits resources for three primary reasons: first, to ensure seasonal reserve requirements are met by

appropriately accounting for resource availability during periods of highest risk; second, to inform long-term investment and retirement decisions by accurately representing the capacity value of a resource in the prompt year; and finally, to appropriately compensate resources for operating practices and attributes that serve the greatest system need. If the accreditation methodology does not align risk, resource availability, and system needs, it results in inefficient market outcomes as well as improper market signals that may leave the system in danger of not having a reliable, cost-effective mix of resources.

Q. WHAT METHODS ARE COMMONLY USED FOR RESOURCE ACCREDITATION FOR THE PURPOSES OF RESOURCE ADEQUACY?

A. One effective way to classify accreditation methods is by separating them into deterministic and probabilistic methods.

Deterministic methods use estimates, generally based on historical performance, to determine resource accreditation. Examples of deterministic methods are seasonal performance, performance during peak load hours, performance during peak net load hours, or performance during historical risk periods.

Probabilistic methods rely on a probabilistic model to examine the loss-of-load probability in the system and how it relates to the performance of resources within that model. The most common probabilistic methods for accreditation include ELCC, equivalent firm capacity (EFC), and marginal reliability improvement (MRI).

The Energy Systems Integration Group (ESIG) provides a comprehensive review of accreditation methods used in the industry.[7] The methods relevant to this filing are further described in this testimony.

Q. HOW DOES MISO CURRENTLY ACCREDIT THE RESOURCES RELEVANT TO THIS FILING?

A. MISO currently uses multiple methods to accredit resources, based on the resource type. See Figure 3 below for an overview of current accreditation methodologies, which can be summarized as follows:

- Thermal resources are accredited pursuant to Schedule 53 of MISO's Tariff.
- Wind resources are accredited through a probabilistic modeling approach to calculate the average ELCC. The class level accredited value is then allocated to individual wind resources based on their actual performance during seasonal peak hours.
- Existing solar resources receive capacity credit based on their actual performance during seasonal peak hours. New solar resources receive a seasonal class average value of 50% for the Summer, Fall, and Spring Seasons, and 5% for Winter.
- Similarly, storage resources receive capacity credit based on their actual performance during seasonal peak hours and new storage resources receive a seasonal class average value of 95%.

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[7] ESIG "New Design Principles for Capacity Accreditation" https://www.esig.energy/new-design-principles-for-capacity-accreditation/

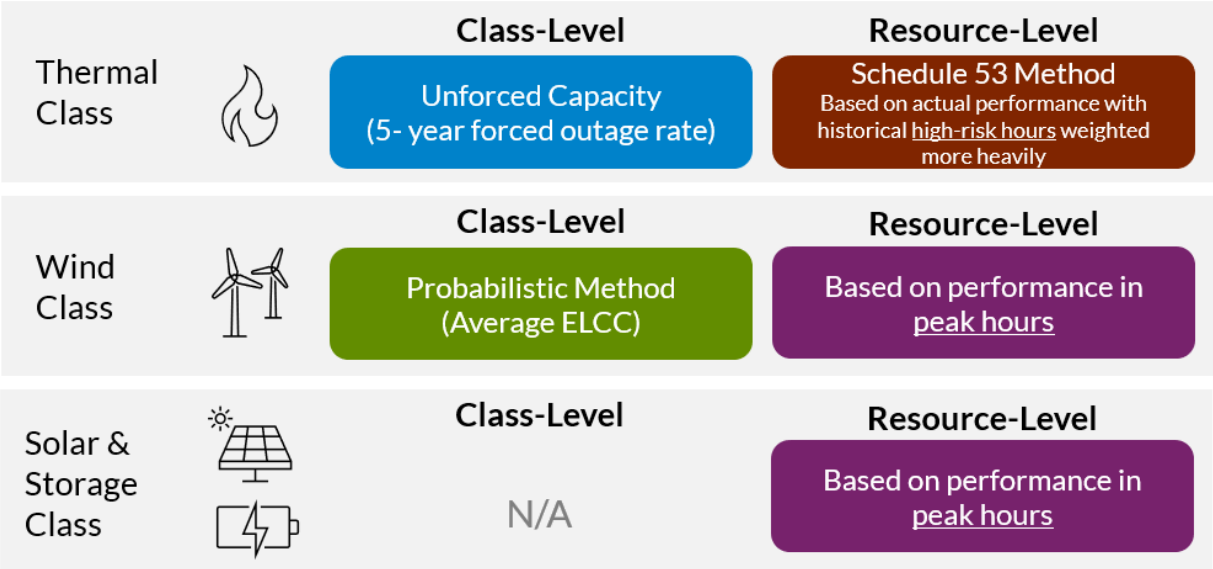

Figure 3: MISO's current accreditation methodology

Q. WHAT ARE THE KEY ISSUES WITH OR LIMITATIONS OF MISO'S CURRENT ACCREDITATION METHODOLOGIES?

A. MISO's current accreditation methodologies have been developed and implemented over time as the resource fleet and reliability needs evolved in the MISO footprint. The application of these different methodologies was appropriate relative to the reliability risks presented at the time of their development. However, and as previously stated, one of the biggest challenges for MISO's Resource Adequacy construct is that periods of highest reliability risk are shifting and are decoupling from times of highest demand. MISO's current accreditation approaches vary amongst resource types, but none of them focus on the marginal contribution of resources during expected periods of highest reliability risk in the probabilistic model. The current approaches thus may result in inaccurate, inconsistent, and potentially overstated accreditation values.

For instance, the Commission recently accepted changes to the accreditation of thermal resources as part of MISO's Seasonal Accreditation (SAC) filing, which established

Schedule 53 of the Tariff.[8] While Schedule 53 enhances the accreditation of thermal resources, it is based on performance across all hours in a Season during the past three years, which does not take into account the effects of possible future events that drive periods of higher risk (such as widespread winter storms). Moreover, by its terms, Schedule 53 is applicable only to thermal resources and Demand Response Resources. Solar and storage resources continue to be accredited based on performance during historic peak load hours, while the risk continues to shift outside of those timeframes. And wind resource accreditation is based on the average ELCC, which can overestimate the capacity value of resources. This issue is further discussed in both the Testimony of Mr. Ming and the Affidavit of Dr. Patton.[9]

This disparity in methods leads to resource accreditation results that are not consistent across resource classes and, importantly, does not allow for the substitution of the accredited capacity of resources on a comparable basis. Similarly, all these methods have the potential to inflate accredited values at the class level, which would lead to an overestimation of how resources contribute to reliability during times of risk and leads to higher reliability requirements. Relying on resources that have received capacity accreditation higher than their actual contribution can lead to incorrect signals for long-term investment and retirement decisions, as well as inefficient market outcomes because even more resources are needed to maintain system reliability.

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[8] *Midcontinent Indep. System Operator, Inc*., 180 FERC ¶ 61, 141 (2022).

[9] *See* Testimony of Mr. Ming ("Ming Testimony") at Q44 and Affidavit of Dr. Patton ("IMM Affidavit") at P21.

Q. IS MISO'S DLOL-BASED METHODOLOGY A TYPE OF MARGINAL ACCREDITATION?

A. Yes.

Q. DESCRIBE HOW MISO'S DLOL-BASED ACCREDITATION METHDOLOGY IS SIMILAR TO A MARGINAL ELCC ACCREDITATION METHOD.

A. MISO's DLOL-based accreditation methodology is consistent with a marginal ELCC framework. The proposed method measures each resource's marginal contribution to reliability during periods of the highest risk (i.e., Critical Hours), and by design it will always capture the risk driven by the evolving resource portfolio in the MISO footprint. As discussed in the Direct Testimony of Mr. Zachary Ming, the marginal ELCC framework measures the reliability value of the next incremental addition of a specific resource type, which is equivalent to measuring the availability of all resources of that resource type during the periods of highest reliability risk. Moreover, the proposed DLOL-based methodology enhances MISO's application of a marginal ELCC accreditation framework by accrediting individual resources based on their historical availability during times of risk.

Q. WHY DOES MISO REFER TO ITS PROPOSED METHODOLOGY AS THE DLOL-BASED METHODOLOGY?

A. While MISO's proposed accreditation methodology is conceptually similar to marginal ELCC, MISO refers to its methodology as "DLOL" because it uses the Critical Hours (loss of load hours plus low margin hours) directly from the probabilistic model to determine the accredited value of each Resource Class (as described in detail below). It is effectively marginal because it measures each resource's marginal contribution during the Critical

Hours, which are representing the periods of highest reliability need. And it is inherently dynamic such that it will always capture the risk driven by the evolving resource portfolio in the MISO footprint.

Q. HOW DOES THE PROPOSED ACCREDITATION METHODOLOGY ALIGN WITH MISO'S MARKET VISION AND MARKET DESIGN GUIDING PRINCIPLES?

A. As discussed in Mr. Ramey's testimony, MISO's market vision is to foster wholesale electricity markets that deliver reliable and economically efficient outcomes. MISO's Market Design Guiding Principles are an important guide to evaluating and developing market enhancements, including this proposed accreditation reform. These guiding principles are listed below:

- Support an economically efficient wholesale market system that minimizes cost to distribute and deliver electricity;
- Facilitate non-discriminatory market participation regardless of resource type, business model, sector or location;
- Develop transparent market prices reflective of marginal system cost and cost allocation reflective of cost-causation and service beneficiaries;
- Support Market Participants in making efficient operational and investment decisions; and,
- Maximize alignment of market requirements with system reliability requirements.

The proposed accreditation methodology is consistent with MISO's Market Design guiding principles supporting efficient wholesale markets as it aligns market requirements with system reliability requirements, facilitates non-discriminatory market participation, results

in transparent market prices that accurately reflect the marginal reliability contributions during Critical Hours, and supports efficient operational and investment decisions.

Q. WHAT ARE THE PRIMARY BENEFITS OF THE PROPOSED ACCREDITATION APPROACH?

A. The proposed accreditation methodology is a balanced approach that captures a range of reliability risks in both the planning and operations horizons by incorporating forward-looking probabilistic analysis along with a resource's actual performance during recent periods of high system risk. The DLOL-based methodology uses a probabilistic model to estimate the expected contribution to reliability of each Resource Class under a wide range of system conditions, while Tier 1 and Tier 2 RA Hours (as currently defined in Schedule 53 and to be incorporated in Schedule 53A of the Tariff) deterministically measure the actual performance of individual resources during historical periods of highest system risk. The combination of the Resource Class-level accreditation and resource-level allocation methodologies accounts for both expected risks in the future and operational risk that has been realized in the recent past (Figure 4 below).

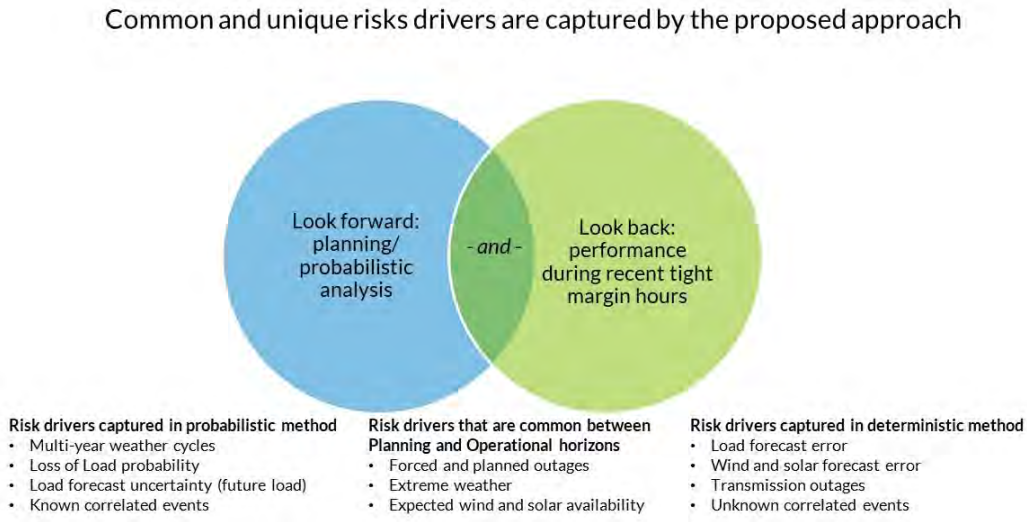

Figure 4: A wide range of risks challenge resource adequacy; a new accreditation approach is needed to capture different risk factors

The proposed DLOL-based accreditation methodology provides the following significant benefits when compared to other accreditation methodologies including:

1. Aligns accredited resource values with expected performance during high-risk hours of operation;
2. Provides a consistent determination of accreditation across all Resource Classes, which is an improvement over the current practice of employing different approaches for different classes. By accrediting all resources during the same time periods and using the same methodology, direct substitution from one class to another is possible as they offer equivalent marginal reliability contribution per accredited MW. This allows resource owners to make the most rational decision for their needs and occurs without altering the overall reliability of the system;
3. Aligns the determination of the system Planning Reserve Margin Requirements (PRMR), Local Reliability Requirements (LRR), and resource accreditation

values used to meet these requirements through the same underlying probabilistic model;

4. Reflects interactions between Resource Classes. Under the DLOL-based methodology, correlations between Resource Classes and their availability during periods of highest system risk are accounted for through the use of a single probabilistic analysis. As each Resource Class has a unique set of operating characteristics, there is value in having a diversified system portfolio and capturing the interactions between all Resource Classes within the same probabilistic analysis. This results in more accurate accreditation and recognizes how the composition of Resource Classes within the system influences system risk;
5. Disentangles random factors that may have occurred historically, such as severe weather or catastrophic outages, from the expected performance characteristics of a resource under the wide variety of events that are captured in the probabilistic model. Relying only on historic events may distort a resource's accreditation causing that resource to appear to have a reliability value that is different than what it truly possesses. The DLOL-based methodology allows the true reliability value of all resources to be more accurately estimated;[10]

[10] A good example of this is provided by wind resources. During a three-year lookback period, there may have been random events that can cause wind resources to have performed significantly better or worse than their expected performance. By using a probabilistic model that captures a wide variety of conditions, the true expected performance signal can be distinguished from the short-term fluctuations that may cause a resource to be mis-accredited.

6. Unlike certain other accreditation methodologies (e.g., those based on average resource accreditation), the DLOL-based methodology does not alter the risk profile on the system and allows for measurement of the actual contribution of resources during times of greatest risk; and,
7. Informs efficient investment in and retirement decisions of resources. By accrediting Resource Classes using the DLOL-based methodology, resource owners are sent the proper signals to invest in resources that offer the greatest reliability value and most economically achieve target reliability. The DLOL-based accreditation methodology provides resource owners with the information necessary to ensure integrated resource plans include resources with the necessary attributes to maintain resource adequacy within the MISO Region.

These benefits work together to generate a system that is economically efficient and achieves the target reliability performance level. The proposed method provides the proper incentives to maintain a diversified resource mix while recognizing the different performance characteristics of the designated Resource Classes. It does this in a computationally and intuitively efficient way without the need for artificial adjustments that may be arbitrary and complex. Additional benefits of this "blended" approach are further described in Section VI of my testimony.

Q. WHY IS THE PROPOSED DLOL-BASED METHODOLOGY (OR MARGINAL ACCREDITATON) A JUST AND REASONABLE RESOURCE ACCREDITATION APPROACH IN THE MISO REGION?

A. The proposed accreditation methodology is just and reasonable for the MISO region because of the following key benefits and aspects that I have described in detail above:

1. It is non-discriminatory and equally applicable to all types of Resources irrespective of fuel-type and/or technology;
2. It addresses the challenges I described above with the current methodologies – specifically, it accredits resources based on their expected performance during the periods of highest reliability risks; and provides direct alignment between accreditation and planning reserve requirements;
3. It provides appropriate signals for long-term investment and retirement decisions by accurately capturing resources' marginal contribution to reliability; and,
4. It will reduce overall cost and improve the ability to achieve and maintain target system reliability during operations, by accurately capturing resources' marginal contribution to reliability.

I also note that the Commission has already accepted the resource-specific accreditation methodology incorporated in the current proposal, which is currently set forth in Schedule 53 of the Tariff. The proposed DLOL-based methodology builds on the deterministic, resource-specific accreditation approach set forth in Schedule 53 by adding a probabilistic component to determine Resource Class accreditation values, and by applying the proposed methodology to all Schedule 53A Resources.

Q. WHY IS IT IMPORTANT THAT MISO CHANGE ITS RESOURCE ACCREDITATION METHODOLOGY AT THIS TIME?

A. As described above and in Mr. Ramey's testimony, MISO is at an inflection point in its resource portfolio evolution. Increasing penetration of wind and solar generation are shifting the nature of system risk.[11] Existing accreditation methods are not sufficiently robust to capture those risks and are unable to send the proper signals to help ensure the availability of resources needed during Critical Hours. As Market Participants plan rapid changes to their generation fleet, it is important for MISO to adopt an accreditation method that captures performance and availability of resources during the periods of system risks to ensure Resources needed to maintain overall reliability of the Bulk Electric System are appropriately incentivized. Inaccurate accreditation sends the wrong signals for the resources needed to maintain system reliability and can leave the MISO system ill-prepared for high-risk operations when resources are most needed. It is essential to make a course correction in MISO's accreditation methodology as soon as possible to provide proper guidance to Market Participants and regulators who are actively planning future resource additions and changes to the grid.

IV. PROPOSED ACCREDITATION METHODOLOGY

A. OVERVIEW OF DLOL-BASED ACCREDITATION METHODOLOGY

[11] *See* MISO's Attributes Roadmap (December 2023), available at: https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf;

See also MISO's Renewable Integration Impact Assessment, Summary Report (February 2021), available at: https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf

Q. PLEASE DESCRIBE THE ACCREDITATION METHODOLOGY MISO IS PROPOSING.

A. MISO is proposing to reform its capacity accreditation methodology for all Schedule 53A Resources, using a two-step process.

First, Resource Class-level accreditation, in megawatts (MW), will be calculated directly from MISO's LOLE analysis (which is a probabilistic analysis). This step calculates the expected availability of each resource during Critical Hours, which include loss-of-load hours and low margin hours, within the probabilistic model and aggregates these values to the Resource Classes that are established in Schedule 53A of the Tariff.

The second step of the proposed accreditation methodology utilizes the same concept that has been previously accepted by the Commission and currently implemented for Schedule 53 Resources. The Resource Class-level accredited value (MW), determined by the probabilistic component of DLOL-based methodology described above, is allocated among the individual resources in a Resource Class on a pro-rata basis using their contribution to the class-level historical performance. Historical performance, or Intermediate Seasonal Accredited Capacity (ISAC), is calculated using a two-tiered weighting structure based on an individual resource's average real-time availability during Tier 1 and Tier 2 RA Hours, as currently defined in Schedule 53 of the Tariff and as incorporated in the proposed Schedule 53A. Tier 2 RA Hours are identified based upon the prior three years of operational experience. These hours represent the periods of highest risk and greatest need during a Season and throughout the year during the past three-year period. They include Emergency Declaration periods and the hours when the operating margin is at its lowest. Tier 2 RA Hours receive 80 percent of the weight, while Tier 1

Hours, which include all other hours during the Season, are weighted at 20 percent. Allocating the Resource Class-level accredited value among the individual resources in a Resource Class based on their historical performance during the periods of highest risk will create performance incentives for individual resources and is expected to improve performance over time when those resources are needed the most. Figure 5 below provides a high-level summary of the design features of the proposed accreditation methodology.

Design Feature	Resource Class-level UCAP	Individual Resource ISAC
Approach	Probabilistic/Prospective	Deterministic/Retrospective
Hours Used	Critical Hours = Loss of Load (LOL) hours + low margin hours Loss of load hours = hours with unserved energy Low margin hours = hours with incremental generation ≤ 3% of the load	Tier 1 and Tier 2 RA hours
Hour Cap	If # of LOL hours ≥ 1,950 in a Season, No Cap If # of LOL hours < 1,950 in a Season, Cap of 1,950 Hours per Season	If # Max Gen hours per Season per Planning Year < 65 Hours, Tier 2 RA Hours capped at 65 Hours
Margin Calculation	Low margin hours are determined from the difference between modeled generation and load + net imports then capped at 3% of load	Operating margin to determine the hours to use for Tier 2 RA hours is based on historical margin as defined in the Schedule 53A
Availability Calculation	Average availability during Critical Hours	(Average availability in Tier 1 hours * 20%) + (average availability in Tier 2 RA hours * 80%)
Planned and forced outage treatment	Included utilizing 5-year annualized planned maintenance rates and 5-year seasonal forced outage rates	Included unless a planned outage meets exemption criteria
# of years analyzed	30 historical correlated load and weather years, 5 load forecast errors and numerous outage draws	3 years

Figure 5: Comparison of key design features for each step of the proposed two-step accreditation methodology

B. CLASS-LEVEL ACCREDITATION CALCULATION

Q. PLEASE DESCRIBE THE KEY COMPONENTS OF THE PROPOSED DLOL-BASED ACCREDITATION METHODOLOGY?

A. The key components of the proposed accreditation methodology include: the determination of Resource Classes; identification of Critical Hours; the determination of LOLE and PRMR through MISO's probabilistic analysis; and, the determination of Tier 1 and Tier 2 RA Hours. Each of these key components is described in detail below.

Q. PLEASE DESCRIBE HOW THE RESOURCE CLASS-LEVEL ACCREDITATION IS CALCULATED USING THE DLOL-BASED METHODOLOGY.

A. The Resource Class-level accreditation value will be determined directly from MISO's probabilistic analysis that is currently used by MISO to meet its annual and seasonal LOLE targets. This step determines the expected availability of each Resource Class during Critical Hours observed in the probabilistic model. Critical Hours are defined as the set of loss of load hours (all hours with unserved energy) and hours in which the difference between available generation (including net imports) and load is equal to or less than three percent (3%) of the load in the probabilistic model. For those Seasons with greater than or equal to 1,950 loss of load hours, Critical Hours will include all loss of load hours. For any Season with less than 1,950 loss of load hours, Critical Hours will also include low margin hours comprised of those hours where available generation in excess of load is less than or equal to 3% of load in that hour in the Season. Once the Critical Hours are identified for each Season, weights are calculated for each of the Critical Hours such that the hours with lowest margin (or highest unserved energy) receive the largest weight while the highest margin hours will receive the lowest weight. After calculating the weights for each Critical Hour, Critical Hours will be capped at 1,950 hours for each Season that has less than 1,950 loss of load hours. Finally, the Resource Class-level accredited value (MW) will be calculated as the weighted average of each Resource Class's performance during the Critical Hours by Season. MISO has proposed to adjust its definition of Unforced Capacity (UCAP), to reflect this Resource Class-level accredited value. Figure 6 illustrates the sequence of events described above.

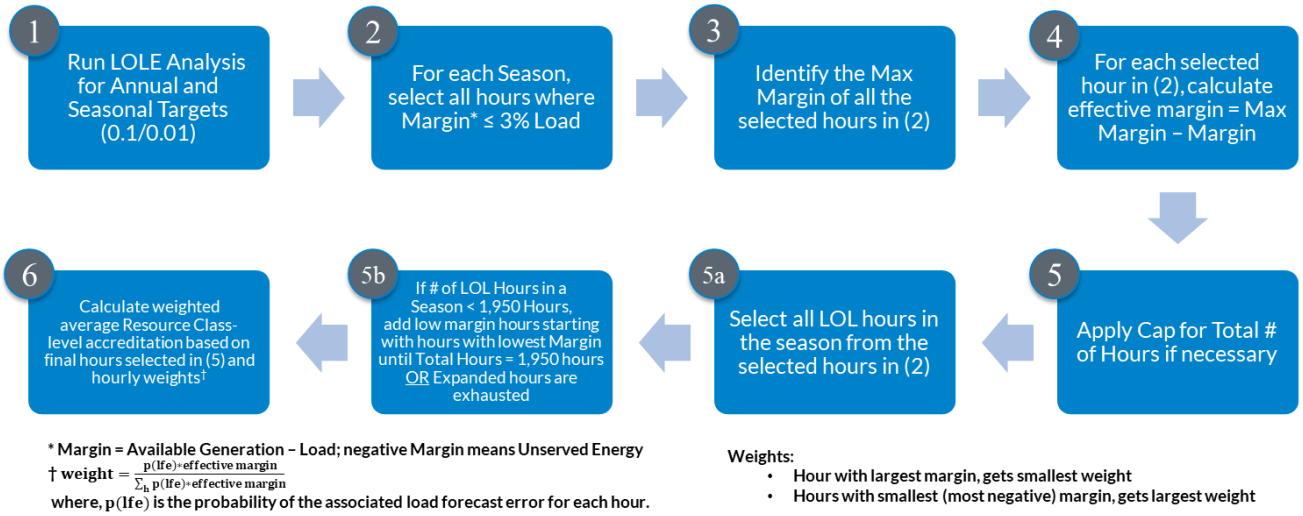

Figure 6: Flow chart of Resource Class-level Accreditation Calculation

Q. PLEASE GIVE AN OVERVIEW OF MISO'S PROBABILISTIC ANALYSIS USED FOR CALCULATION OF RESOURCE CLASS-LEVEL ACCREDITATION.

A. As described above, the Resource Class-level accreditation value will be determined directly from MISO's probabilistic analysis that is currently used by MISO to meet its annual and seasonal LOLE targets. MISO's LOLE analysis includes a Monte Carlo probabilistic simulation using 30 years of correlated load and weather data for each of five load forecasts that incorporates economic uncertainties and associated probabilities into the forecasts. MISO determines the adjustment to capacity in the probabilistic model that would bring the MISO system to the 1 day in 10 years LOLE standard on an annual basis. Under MISO's Seasonal Resource Adequacy Construct, the annual LOLE of 0.1 days/year is not evenly applied across each Season and is dependent on observed risk in the model, although each Season must show a minimum LOLE of 0.01 days/year. If, on an annual basis, a Season is not showing a minimum of 0.01 LOLE, modeled capacity is further reduced through a negative adjustment unit to find the point at which risk is at least equal to the minimum LOLE target of 0.01 days/year. Further details about the application of

MISO's resource adequacy LOLE modelling process are described in Section V of my testimony.

Once the Monte Carlo simulations are complete and seasonal LOLE targets are met, MISO will calculate the Resource Class-level accreditation and seasonal Resource Adequacy Requirements as further described below.

Q. PLEASE DESCRIBE HOW MARGIN IS CALCULATED TO IDENTIFY CRITICAL HOURS FROM THE LOLE MODEL.

A. MISO calculates margin for each hour of each Season for all iterations included in its LOLE analysis. The margin is calculated as the difference between total available generation, including net imports, and load, for the hour. The MW adjustment to reach the seasonal LOLE targets is included in the total available generation.

$$margin = \sum generation - load + net\ imports$$

Once margin is calculated, MISO identifies all hours with margin that is equal to or less than 3% of the load for the hour in each Season. This includes two subsets of hours: i) a loss of load hour, where there was a loss of load due to available generation being less than the required load, i.e. when margin is negative, and ii) low-margin hours, where there was no loss of load, i.e. when margin is positive, but less than 3% positive margin.

Q. WHY WAS A 3% MARGIN CHOSEN FOR USE IN THE DETERMINATION OF CRITICAL HOURS?

A. MISO chose a margin of 3% as it provides a good balance between stability of results and highest-risk hours. These highest-risk hours are representative of periods when MISO typically would issue Emergency Declarations in real-time. MISO originally considered only the loss of load hours as the Critical Hours in its proposed design. Through the review

of preliminary results based on its original design of considering loss of load hours only, and stakeholder discussions on the proposed original design, MISO identified possible scenarios where Seasons may experience too few loss of load hours and where hours with increased reliability risks may not otherwise be included. This could occur, for example, where the available generation is just enough and slightly higher than the load but not enough where there is sufficient margin to be considered as low reliability risk. Additionally, the scenario of low number of loss of load hours in any Season also introduces the possibility of instability in the year-over-year results. In response to these issues, MISO expanded the number of hours used to develop the Resource Class-level accreditation to include low margin hours.

The decision to expand hours for stability and accredit performance during the highest risk hours, however, also creates a tension. Margins as high as 5% dilute the signal being sent by the highest-risk hours, while a margin as low as 1% may potentially skip hours with increased reliability risks and may potentially introduce instability in the results year-over-year, especially for the Seasons when LOLE target is as small as 0.01 day in a year. The proposal to use 3% margin to identify low margin hours for inclusion in Critical Hours from the probabilistic model provides an appropriate balance between the need for stability and the need for accurately reflecting the resource performance during the periods of highest reliability risks.

Q. PLEASE DESCRIBE HOW MISO CALCULATES WEIGHTS AND THE CAP FOR CRITICAL HOURS.

A. After selecting all loss of load hours and low margin hours for each Season, MISO will use the following steps to calculate weights for each selected hour and then apply a cap, if necessary, to calculate Resource Class-level accreditation:

1) Within each Season, the hour with the maximum positive margin is identified from all the low margin hours. This "max margin" is the single maximum margin across all 30 weather years such that there are four (4) total max margin values, one (1) for each Season.

2) Next, for each hour identified in Step 1, effective margin is calculated relative to the max margin hour. This ensures that all values are positive, which is necessary for a weighted sum operation and ensures that the hour with largest unserved energy has the greatest weight, while the hour with the largest margin receives the smallest weight. If the hour with the max margin is included, this hour will receive zero weight.

$$effective\ margin = \max margin - margin$$

3) The number of Critical Hours to be used is capped within each Season based on the following procedure:

   i. All loss of load hours are used in the final calculation, regardless of the number of loss of load hours. Using all loss of load hours regardless of the number of loss of load hours is vital to fully capture all the expected reliability risks observed in the probabilistic model.

ii. If there are fewer than 1,950 loss of load hours per Season, MISO proposes to use low margin hours for the Resource Class-level accreditation calculations but cap the total number of Critical Hours at 1,950. For this step, hours with positive margin are selected beginning with the smallest effective margin until the cap is reached or until all low-margin hours within the Season have been selected. If the total number of Critical Hours are fewer than 1,950 hours between the loss of load hours and low-margin hours, then all loss of load hours and low-margin hours are used, and the cap will not be reached. Loss of load hours will never be excluded, and hours with greater than a 3% margin will never be included in the final selection of Critical Hours for Resource Class-level accreditation calculations. Figure 7 provides an example of how MISO will utilize loss of load hours and low margin hours to identify Critical Hours used for the Resource Class-level accreditation calculations.

Case	Type of hour	Summer	Fall	Winter	Spring
PY23-24	Loss of Load (LOL)	2,703	265	201	240
	LOL + low margin hours*	7,394	934	1,118	1,562
	Used for Resource Class-level UCAP calculations	2,703	934	1,118	1,562

*Low margin hours are all non-LOL hours with margin < 3% load

Figure 7: Example of loss of load hours and low margin hours to identify Critical Hours

4) Next, the weights are calculated and normalized using: a) the probability associated with the load forecast error scenario within the probabilistic model that the selected Critical Hour belongs to, and b) the effective margin developed in Step 2 above. The weights are normalized so that the sum equals one (1).

$$weight = \frac{p(lfe) * effective\ margin}{\sum_h p(lfe) * effective\ margin},$$

where $p(lfe)$ is the probability of the associated load forecast error for each hour. The load forecast error (LFE) values are included in the probabilistic analysis to account for economic load uncertainty and is documented in further detail in MISO's LOLE Study Report.[12] By way of example, the probability associated with each load forecast error that was used in the Planning Year 2023-2024 LOLE Study can be found in Figure 8 below.

LFE Levels				
-2.0%	-1.0%	0.0%	1.0%	2.0%
Probability assigned to each LFE				
4.8%	24.1%	42.1%	24.1%	4.8%

Figure 8: Probability associated with each load forecast error

5) Finally, the total availability is calculated for a Resource Class for each Critical Hour designated in step 3, and those values are averaged for each Season using the weights discussed in step 4. This results in the Resource Class-level accreditation, referred to as Resource Class-level UCAP in the MISO Tariff.

The seasonal Resource Class-level UCAP calculated using the steps described above represents the megawatts that a Resource Class is expected to contribute during times of highest reliability risk expected during the Season.

[12] See Section 3.3.2 in the PY2023-2024 LOLE Study Report

Q. WHY IS MISO WEIGHTING THE HOURS?

A. Weighting the hours based on margin recognizes that not all the simulated events are equal, by assigning greater weights to those hours that have the highest unserved energy. It also provides a distinction between loss of load hours (with negative margins) and low margin hours (with zero or small positive margins), by providing higher weights to the former. The weighting system ensures that the expected reliability risk during Critical Hours is being appropriately accounted for in the Resource Class-level accreditation calculation.

Q. WHY WAS THE PROPOSED WEIGHTING SCHEME CHOSEN?

A. MISO considered alternative weighting schemes, ranging from equal weights for all hours, weights based on the amount of unserved energy, combining the loss of load hours and low margin hours with a fixed ratio (similar to the combination of Tier 1 and Tier 2 RA hours in Schedule 53), and alternative weighting based on margin. The selected scheme was chosen because it provides consistent emphasis on the hours with highest unserved energy, thereby appropriately accounting for the magnitude of expected reliability risks in each hour. Moreover, the approach chosen preserves the ordering of hours with respect to margins (so hours with larger positive margins always receive smaller weights), and it is numerically stable regardless of whether the group of hours include only loss-of-load hours, a few low margin hours, or a large number of low margin hours.

Q. PLEASE EXPLAIN WHY A CAP ON THE NUMBER OF LOW MARGIN HOURS IS NEEDED.

A. Because system risk is not evenly distributed across Seasons, the number of loss of load hours found in the probabilistic model varies widely across Seasons. Figure 7 above, shows that for the Planning Year 2023-2024 simulations, the Summer Season experienced

2,703 hours with unserved energy, but the rest of the Seasons did not exceed 265 hours. Critical Hours were considered to avoid calculating accreditation values in a small group of hours for the less critical Seasons, which could lead to numerical instability and large variations in results year over year.

Hours are capped to establish a balance between improving numerical instability (by including low number of hours) and diluting the contribution of loss of load hours, if they represent too small of a fraction of the total Critical Hours. The cap for number of system hours and the use of the weighting described above work together to prioritize the hours that are most critical from reliability risk perspective and take advantage of the larger pool of hours for the calculations.

Q. WHY IS A CAP OF 1,950 HOURS WHEN LOW MARGIN HOURS ARE INCLUDED IN THE CRITICAL HOURS REASONABLE?

A. Applying the logic of 65 Tier 2 Resource Adequacy (RA) hours per Season from the current Schedule 53 calculations for each of the 30 weather years used in the probabilistic model, MISO selected 65 hours times 30 weather years, which equals 1,950 hours per Season as the cap when low margin hours are included in the number of hours for the Resource Class-level UCAP calculations. As Figure 7 above shows, the number of loss of load hours in the Summer exceeds the cap in the example for Planning Year 2023-24 and the cap is not binding in the rest of the Seasons.

C. ALLOCATION OF CLASS-LEVEL UCAP TO INDIVIDIUAL RESOURCES

Q. PLEASE DESCRIBE HOW RESOURCE CLASS ACCREDITATION IS ALLOCATED TO INDIVIDUAL RESOURCES WITHIN A RESOURCE CLASS.

A. MISO's resource-level accreditation proposal builds on the Commission-approved SAC methodology for Schedule 53 Resources. As described above, once Resource Class-level accreditation values have been determined based on the probabilistic analysis, MISO will then allocate the Resource Class-level accreditation values (MW) to individual resources within the Resource Class based on their historic performance (ISAC) as set forth in Schedule 53A.

Tier 1 and Tier 2 RA Hours over the previous three years of operations are used to determine resource availability for calculating seasonal ISAC. Tier 1 Hours will determine each resource's real-time availability during normal operating condition hours, and Tier 2 RA Hours will determine each resource's real-time availability during hours with the most difficult operating conditions, including declared maximum generation events. Tier 2 RA Hours are more heavily weighted so that most of a resource's real-time availability will be based on its availability during times of greatest reliability need.

All foundational aspects of MISO's current Schedule 53 Tariff, including outage exemptions, tier weighting, and lead time considerations, remain unchanged except the process to determine a resource's availability for the deficient hours (currently referred as Annual Average Offered Capacity in Schedule 53), when there are less than 65 Tier 2 RA hours in a Season, as discussed further below.

The use of Tier 1 and Tier 2 RA Hours ensures that individual resources are compared to other resources within their Resource Class when the system experiences the highest operational risk. For instance, resources in the solar class may have no output during evening risk hours, but all resources would be affected in the same manner and the allocation within the class would not be impacted. Resources with better performance

during Tier 1 and Tier 2 RA Hours receive a larger slice of the overall Resource Class-level UCAP.

The allocation of Resource Class-level UCAP among all Resources in the Resource Class can be described using the following equation:

$$SAC_i = Resource\ Class\text{-}Level\ UCAP * \frac{Resource\ ISAC_i}{Resource\ Class\text{-}level\ ISAC}$$

Q. PROVIDE AN EXAMPLE OF HOW RESOURCE CLASS-LEVEL UCAP IS ALLOCATED TO INDIVIDUAL RESOURCES WITHIN A RESOURCE CLASS TO DETERMINE THE SEASONAL ACCREDITED CAPACITY.

A. Figure 9 below provides a simplified example of how the Resource Class-level UCAP determined by the DLOL-based methodology is allocated to individual resources in a five-resource class. First, the ISAC for each resource is calculated by weighing Tier 1 Hours at 20% and Tier 2 RA Hours at 80%. The Seasonal Accredited Capacity (SAC) for each resource is calculated by distributing the Resource Class-level UCAP from the probabilistic model, 50 MW, among the units, proportional to their ISAC value. Lastly, each resource's percentage credit is calculated by dividing the resource's SAC by its Installed Capacity (ICAP) value.

Resource	ICAP	Tier 1 Hour Availability	Tier 2 RA Hour Availability	Intermediate SAC (ISAC)	Final SAC	% Credit (SAC/ICAP)
Resource Class-Level UCAP determined by DLOL method from LOLE analysis = 50 MW [U]						
Unit 1	5	2	3	2.8	2.6	52%
Unit 2	10	7	8	7.8	7.3	73%
Unit 3	15	12	14	13.6	12.7	85%
Unit 4	20	10	16	14.8	13.9	69%
Unit 5	25	12	15	14.4	13.5	54%
Total	75	43	56	53.4	50	67%
Formula	[A]	[B]	[C]	[D] = 0.2 * [B] + 0.8 * [C]	[E] = [U]*([D]/Total of [D])	[F] = [E]/[A]

ISAC = (Avg. Tier 1 Hour Availability x 20%) + (Avg. Tier 2 RA Hour Availability x 80%)

Final SAC = Resource Class-level UCAP * (Individual Resource ISAC/Resource Class-level ISAC)

Figure 9: Example of allocation of Resource Class-level accreditation among all Resources within the Resource Class.

Q. WHY IS MISO PROPOSING TO REPLACE ANNUAL AVERAGE OFFERED CAPACITY (AAOC) WITH SEASONAL RESOURCE CLASS-LEVEL UCAP, AS A PERCENTAGE OF RESOURCE CLASS-LEVEL INSTALLED CAPACITY?

A. If there are less than 65 Tier 2 RA Hours in a Season (deficient hours), seasonal Resource Class-level UCAP, as a percentage of Resource Class-level ICAP, is used to determine a resource's availability during those deficient hours. The Resource Class-level ICAP is the sum of the individual ICAP of all resources in a Resource Class. This is a slight deviation from the existing Schedule 53 methodology for filling deficient hours as this process will replace AAOC. MISO is proposing to change only this aspect of the current Schedule 53 methodology to ensure both that the availability of highly variable resources (e.g., wind and solar) is appropriately accounted for in the calculation of a resource's ISAC and to have a uniform method for accreditation of all resources. The current AAOC approach for the deficient RA Hours in any Season works well with Schedule 53 Resources because

their availability across the year does not significantly vary. In contrast, intermittent resources are highly variable in nature and their availability during an RA Hour (or Maximum Generation event) in a Season is likely to be different than their availability during RA Hours in other Seasons. For example, the availability of wind resources in a deficient RA Hour occurring during Summer peak conditions would not likely be similar to the average availability of those resources during RA Hours in the rest of the Seasons. Applying the AAOC approach, however, would result in application of those otherwise non-comparable hours during Seasons when there is an RA Hour deficiency. MISO therefore adopted the new proposed methodology to "backfill" deficient RA Hours to help ensure the comparability of all RA Hours being evaluated. When there is a deficient RA Hour in any Season, it is better to use the expected availability of such resources from the probabilistic model than to use their availability during other times of the year. MISO considered having a different approach than AAOC only for the intermittent resources but decided to not pursue that option to have a consistent approach for all resources.

D. SUMMARY OF KEY TARIFF CHANGES AND DESIGN CONSIDERATIONS FOR THE PROPOSED METHOD

Q. WHY IS MISO PROPOSING TO UPDATE THE DEFINITION OF UCAP AND SAC IN MODULE A?

A. MISO is proposing to change the definition of UCAP because UCAP sets the baseline expected availability of a resource for capacity accreditation and the proposal changes the way that baseline is calculated. The existing UCAP definition sets this baseline based on historic forced outage rates or historic availability and does not adequately account for resource availability observed in the probabilistic model. The DLOL-based methodology

marks a fundamental change in determining UCAP such that the probabilistic model is used to set baseline resource availability at the class level, which is then used in place of the previous baseline. Changing the definition of UCAP does not otherwise fundamentally change subsequent Resource Adequacy processes and calculations such that modifying the definition of UCAP is most consistent with MISO's Resource Adequacy construct. I note that both PJM and NYISO have taken similar approaches within their recent capacity market reforms.[13]

Upon receiving stakeholder feedback related to the Tariff redline changes shared with the RASC, MISO reconsidered the definition of SAC and decided to update it to better reflect how the term is currently used in the PRA. This modification is needed to align with the updated definition of UCAP so that the two definitions are distinguishable. SAC is the final accredited capacity, after accounting for the two-step accreditation process, that is convertible to Zonal Resource Credits for use in the PRA.

Q. WILL THE SYSTEM-WIDE UCAP TO ISAC CONVERSION RATIO STILL EXIST UNDER MISO'S ACCREDITATION REFORM PROPOSAL?

A. No. The system-wide UCAP to ISAC conversion ratio that is currently included in Schedule 53 of MISO's Tariff is no longer relevant under the proposed DLOL-based accreditation methodology. As explained in detail above, the proposed methodology is a two-step process. The first step is to calculate the Resource Class-level UCAP from the probabilistic model and the second step is to allocate the Resource Class-level accreditation to individual Resources within the same Resource Class based on their historical

[13] *See* fn.3, supra.

performance in last three Planning Years. The proposed two-step accreditation process no longer requires the system wide UCAP to ISAC conversion ratios to scale the ISAC values.

Q. WHY DID MISO REMOVE THE SYSTEM-WIDE UCAP TO ISAC CONVERSION RATIO IN SCHEDULE 53A?

A. The system wide UCAP to ISAC conversion ratio was put in place to ensure SAC was aligned with how requirements were determined during the probabilistic analysis. In other words, it brought accreditation into the same terms or currency as the requirements. MISO's proposed accreditation methodology naturally aligns accreditation with requirements since both are produced from the same probabilistic model. Therefore, there is no longer a need for the system wide UCAP to ISAC conversion ratio. As a result, MISO decided to adjust the language in Schedule 53A to better describe the process to establish the final SAC value for each resource. The proposed Tariff language aligns with the two-step process described above.

Q. HOW DID MISO ESTABLISH THE PROPOSED RESOURCE CLASSES?

A. The proposed Tariff includes general criteria for determining Resource Classes as well as establishing the specific Resource Classes that will initially apply. MISO considered the operating characteristics, technology, fuel type, and the expected performance of resources in its forward-looking probabilistic model to evaluate the criteria for defining Resources Classes. Ultimately, MISO decided to establish Resource Classes based on similar operating characteristics of individual resources within the class and generally reflect the same or similar technologies. The specific Resource Classes are: Gas (including oil), Combined Cycle, Coal, Hydro, Nuclear, Pumped Storage, Solar, Wind, Storage, Run-of-River, and Biomass. These Resource Classes each possess unique properties that

differentiate themselves from one another and produce a complete set of classes into which each resource can be uniquely assigned. Although Resource Classes are being defined in the Tariff with this filing, MISO intends to periodically review the set of Resource Classes and work with Stakeholders on any proposed changes before making a Tariff filing that would update the defined Resource Classes.

Q. DID MISO CONSIDER COMBINING ALL THERMAL RESROUCES INTO A SINGLE RESOURCE CLASS?

A. Yes. MISO evaluated combining all thermal resources into a single Resource Class. However, MISO decided not to pursue this approach for three reasons. First, there is a significant disparity in the operating characteristics of the different types of thermal resources during various weather events (e.g. cold weather snaps affect Gas resources differently than Nuclear resources). Second, thermal resources are appropriately modeled differently in the probabilistic analysis corresponding to their respective operating characteristics (e.g. Coal, Gas, and Combined Cycle resources have a cold weather outage adder modeled in MISO's probabilistic analysis). Third, such an approach will not provide the appropriate signals to inform retirement and investment decision making with respect to specific Resource Classes, which is one of the primary objectives of the proposed reforms.

Q. HOW WILL MISO DETERMINE WHETHER THE LIST OF RESOURCE CLASSES NEEDS TO BE UPDATED?

A. MISO will continue to monitor its generator interconnection queue, and the changes in its generation fleet to evaluate if the proposed Resource Classes established in the Tariff (Schedule 53A) need to be updated. MISO will also work with stakeholders to determine

whether additional Resource Classes should be established in the future as new technologies emerge and as MISO gains experience with the performance of resources under the DLOL-based methodology.

Q. HOW DOES MISO ENSURE THAT THE PERFORMANCE OF A SINGLE RESOURCE IN THE PROBABILISTIC MODEL DOES NOT UNDULY INFLUENCE THE RESOURCE CLASS-LEVEL UCAP FOR SMALL RESOURCE CLASSES?

A. MISO acknowledges that a single resource can theoretically unduly influence the Resource Class-level UCAP of a small Resource Class. MISO has evaluated preliminary results calculated using the probabilistic model for Planning Year 2023 – 2024 to determine how individual resources in a small Resource Class may impact the Resource Class-level UCAP. For small Resource Classes, particularly Nuclear and Pumped Storage, each resource's modeling and assumptions within the class were consistent in the probabilistic analysis relative to the other resources within the class.

Nevertheless, MISO is planning to establish a quality control/quality assurance (QA/QC) procedure in the Resource Adequacy Business Practices Manual that will track year-over-year changes for the main parameters that determine the performance of each resource in the probabilistic model (e.g., forced outages rates or maintenance rates for thermal units). If this QA/QC check determines that a single resource is unduly influencing the Resource Class-level UCAP, MISO will address the modeling of such resource and/or Resource Class-level UCAP calculations for the corresponding Resource Class on a case-by-case basis.

Q. CAN AN INDIVIDUAL RESOURCE HAVE A HIGHER SAC, AS A PERCENTAGE OF ICAP, THAN THE RESOURCE CLASS-LEVEL UCAP, AS A PERCENTAGE OF ICAP?

A. Yes, some individual Resources will perform better than the Resource Class when comparing their SAC as a percentage of their ICAP if they have better historical performance relative to other resources within their Resource Class. The only situation in which all resources in a Resource Class would have their SAC as a percentage of their corresponding ICAP match the Resource Class-level UCAP to the Resource Class-level ICAP percentage is if all the resources have the exact same behavior during Tier 1 and Tier 2 RA Hours, so that their individual ISAC values are all proportional to ICAP. In all other situations, some individual resources will perform better, and some will perform worse than the Resource Class average. As illustrated by way of the example in Figure 9 above, the Resource Class-level UCAP percentage is 67% of Resource Class-level ICAP, but individual resource SAC values range from 52% to 85% of their respective ICAP values.

Q. HOW WILL PLANNED OUTAGES AFFECT RESOURCE CLASS-LEVEL UCAP?

A. Planned outages are modeled using maintenance rates for each resource in the probabilistic model. Planned outages will reduce capacity availability of Resource Classes within the probabilistic model and commensurately reduce accreditation. By incorporating planned outages, the model will appropriately make resources unavailable to meet load for a period that correlates with their historic average maintenance rates, and along with other resources' availability in the model provides an overall picture of the Resource Class's availability in the probabilistic model. Recognizing planned outages in the probabilistic

model is essential to identify periods of reliability risks and allows the simulated outcomes to better reflect expected availability of resources, especially given that MISO has implemented a seasonal resource adequacy construct. Accounting for planned outages in Resource Class-level UCAP calculations will ensure each Resource Class's contribution to reliability is appropriately accounted for and the approach is aligned with the key objectives of resource accreditation.

Q. HOW ARE ACTUAL PLANNED OUTAGES IN THE RECENT PAST ACCOUNTED FOR IN THE ISAC CALCULATION OF INDIVIDUAL RESOURCES?

A. MISO essentially is leveraging the existing planned outage exemption process that is used for the calculation of ISAC for all Schedule 53 Resources. Under MISO's proposed accreditation methodology, exemptions will also be granted for planned outages as described in Schedule 53A and in MISO's Business Practice Manual (BPM) for Outage Operations. Without an exemption, a planned outage is treated like any other outage and a resource receives zero (0) credit of availability for that hour. With an exemption, the availability of a resource will be calculated by multiplying the seasonal Resource Class-level UCAP as a percentage of Resource Class-level ICAP by the resource's ICAP instead of a zero (0) for that hour during the exempted planned outage. As set forth in Schedule 53A, however, solar resources will not receive planned outage exemptions at night. The specific hours for this exception will be provided in MISO's Business Practices Manual for Resource Adequacy and will be Local Resource Zone (LRZ) and local time specific, in such a way that any daytime operating hour interval will allow for an exemption. As an example, if the sun sets at 20:01, then an exemption will be allowed for

the hour beginning at 20:00. If the sun rises at 06:59, then there will be an exemption allowed for the hour beginning at 06:00 hour. However, no exemption would be provided in this example for a solar resource planned outage scheduled to take place between 21:00 hours and 06:00 hours.

Q. WHY ARE EXEMPTIONS FOR PLANNED OUTAGES APPROPRIATE FOR CALCULATIONS USING THE DETERMINISTIC APPROACH BUT NOT FOR RESOURCE CLASS-LEVEL UCAP CALCULATIONS USING THE PROBABILISTIC APPROACH?

A. Exemptions for planned outages under current Schedule 53 provide an incentive for resource owners to plan outages for their resources in advance and at times most beneficial to operational reliability. Exemptions are also only used to allocate the Resource Class-level UCAP to the individual resources within the Resource Class. This provides an incentive for resource owners with resources within each Resource Class to plan their outages well in advance because they will receive a bigger slice of the overall Resource Class-level UCAP compared to resources within the class that do not plan their outages well in advance. Applying exemptions for planned outages in the prospective probabilistic analysis under Schedule 53A, which is used to calculate Resource Class-level UCAP, would be inappropriate because the probabilistic model needs to identify all possible risks that may impact the reliability of the system. All outages need to be captured to ensure target system reliability is maintained. A planned outage increases the probability of reliability risk being present and this risk should not be ignored in the establishment of a resource's contribution to reliability and determination of Resource Adequacy Requirements. Therefore, for the planning horizon an exemption for a planned outage is

inappropriate while over the operating horizon an exemption is appropriate and improves reliability through prudent outage planning. MISO's operations and outage coordination groups have already started seeing changes in outage scheduling patterns and have also begun to realize some of the associated benefits through the implementation of Schedule 53 outage exemption rules effective for Planning Year 2023 - 2024.

Q. IS THERE A RISK OF "DOUBLE COUNTING" BECAUSE PLANNED OUTAGES ARE CONSIDERED IN THE RESOURCE CLASS-LEVEL UCAP CALCULATIONS AND IN THE CALCULATION OF AN INDIVIDUAL RESOURCE'S ISAC?

A. No. Although planned outages are included in each step of the two-step proposed accreditation process, they are treated differently by design. As described in the two-step process above, Resource Class-level UCAP determines the size of the pie and individual resource ISAC will determine how that pie is split up. The fact that planned outages are included in the two calculations has no bearing on the result because the ISAC is merely used to determine how much of the Resource Class-level UCAP each resource in the Resource Class will receive. All resources within the class are treated the same in regard to outages in their ISAC calculation. Additionally, properly planned resource outages are eligible to receive an exemption for purposes of the ISAC calculation pursuant to Schedule 53A. Providing this exemption for properly planned outages is a mechanism to encourage Market Participants to minimize the number of planned outages during expected periods of highest reliability risk. Resources that plan their outages well in advance will receive a larger portion of the Resource Class-level UCAP. For these reasons, planned

outages are not double-counted in either the Resource Class-level UCAP or ISAC calculation.

Q. SHOULD CRITICAL HOURS IDENTIFIED IN THE LOLE MODEL BE EXPECTED TO MATCH RESOURCE ADEQUACY HOURS THAT ARE USED TO ALLOCATE RESOURCE CLASS-LEVEL UCAP TO INDIVIDUAL RESOURCES?

A. No. As explained previously, the proposed accreditation methodology is a balanced approach that captures a range of reliability risks in both the planning and operations horizons by incorporating forward-looking probabilistic analysis with a resource's actual performance during recent periods of high system risk. By design, therefore, perfect alignment between Critical Hours and RA Hours is not expected. Critical Hours identified in the probabilistic model include a wide range of system conditions (e.g., 30 years of weather data, five different load forecast errors, and hundreds of random outage draws). On the other hand, the three years of operational data used to determine RA Hours represent a limited number of snapshots of different system conditions that were experienced operationally. It is also important to note that Tier 1 and Tier 2 RA Hours are only used to distribute the Resource Class-level UCAP to individual resources and every resource in the Resource Class and Planning Region will utilize the same set of hours.

Also, it is important to note that results from the probabilistic analysis are not expected to and should not exactly match results of the deterministic approach. As indicated previously in my testimony, one of the benefits of the proposed approach is that it disentangles random factors that may have occurred historically from the expected performance characteristics

of a resource and Resource Class under the wide variety of events that are captured in the probabilistic model.

Q. WHY ARE SOLAR RESOURCES TREATED DIFFERENTLY REGARDING SCHEDULE 53A PLANNED OUTAGE EXEMPTIONS?

A. Exemptions are provided to incentivize minimizing the number of planned outages in any given hour. To receive an exemption, a resource generally must plan the outage to occur at least 120 days in advance. Solar is a unique resource where knowledge of fuel unavailability (i.e., when the sun will rise and set) is known 120 days in advance. For other resources, such as wind or gas, fuel unavailability cannot be predicted 120 days in advance. Therefore, there is the ability for solar resource owners to claim exemptions when they know they cannot provide energy. Allowing solar resources to receive an exemption for planned outages taken during night-time hours, and thereby receiving the corresponding seasonal Resource Class-level UCAP value as a percentage of the Resource Class-level ICAP, would distort the accredited capacity value of such solar resources as they appear to be available when it would otherwise be impossible to inject energy into the grid.

Q. HOW IS MISO PROPOSING TO ACCREDIT HYBRID AND CO-LOCATED RESOURCES?

A. Co-located resources that share an interconnection service limit will be accredited according to each of the resources' chosen participation model and their accreditation would equal the sum of the individual components. For example, co-located solar and storage resources will be accredited under the solar and storage Resource Classes, respectively. Because the resources share an Interconnection Service Limit, though, their total Intermediate SAC will be limited by that Interconnection Service Limit since the

combined set of resources cannot deliver MWs above that limit. Resource-level metering and sum of the parts accreditation for co-located resources allows for proper resource accreditation for each potential combination while accounting for a shared interconnection constraint. Even if separate component capabilities could exceed the interconnection service limit, the interconnection limit provides a total upper bound on possible contributions for each interconnection agreement.

Given the above, MISO proposes accrediting single-offer hybrid resources according to their chosen participation model. For example, a solar plus storage hybrid resource operating as a solar Dispatchable Intermittent Resource (DIR) will be accredited under the Solar Resource Class. Creating an accreditation Resource Class for hybrid resources is potentially intractable given the countless combinations of resources that could make up a hybrid resource. Moreover, creating different Resource Classes for each hybrid combination is unmanageable. Solar and storage resources in combination can have significantly different operating characteristics such that a single class for this fuel-type combination would not be meaningful (e.g., differing storage and solar capacity ratios, DC- or AC-coupled design, grid charging or non-grid charging).

Q. ARE LOAD MODIFYING RESOURCES (LMR) INCLUDED IN MISO'S ACCREDITATION REFORM PROPOSAL?

A. No, the proposed methodology does not apply to LMRs. MISO will continue to determine LMR accreditation through the current methods, derived from their past performance (forced outage rates for Behind the Meter Generation LMRs, and testing documentation submitted to MISO for Demand Resource LMRs), as provided in the Business Practice Manual for Resource Adequacy. MISO is currently engaging with stakeholders through its

RASC to improve the accreditation methodology for LMRs, but that effort is separate from the proposed accreditation methodology discussed in this testimony. MISO expects to make a separate filing for LMR accreditation reforms in the future after the design for the proposed changes is final and discussed with the stakeholders.

Q. WHAT IS MISO'S PLAN FOR ACCREDITING EXTERNAL RESOURCES?

A. MISO will continue to accredit External Resources through the current methods, which are derived from historical forced outage rates. Hourly real-time availability data is not currently collected for External Resources as these resources do not participate in MISO markets analogously to other resources. Because External Resources do not participate in the same manner as resources internal to MISO, they are also being treated differently here. MISO will evaluate methods to move all resources, including External Resources, under the proposed methodology in the future.

V. RESOURCE ADEQUACY MODELING

Q. WHAT IS THE LINK BETWEEN MISO'S PROBABILISTIC MODEL AND THE PROPOSED ACCREDITATION METHODOLOGY?

A. The probabilistic model is at the heart of MISO's proposed accreditation methodology because resource accreditation and Resource Adequacy Requirements will be directly determined using the same probabilistic model. Because the probabilistic model is central to the proposed accreditation methodology, I will briefly describe certain aspects of that model in this section of my testimony. Further information on MISO's probabilistic model

is available on MISO's website on the Resource Adequacy page and the Loss of Load Expectation Working Group page.[14]

Q. PLEASE BRIEFLY DESCRIBE THE PROBABILISTIC MODEL USED BY MISO IN ITS RESOURCE ADEQUACY CONSTRUCT.

A. MISO uses Astrapé's Strategic Energy Risk Valuation Model (SERVM) software to conduct the LOLE analysis. The SERVM software uses a sequential Monte Carlo simulation to step through time chronologically on an hourly basis and considers many combinations of random system conditions to evaluate how often system load can be covered by resources. The random system conditions include features such as planned and forced outages at the resource-level, import availability from neighboring system, as well the representation of 30 years of correlated load and other weather-dependent datasets, such as wind or solar generation and cold-weather outages.

Aside from assumed future capacity additions, typically only Capacity Resources that have cleared the most recent PRA are considered in the model. The probabilistic model data is generally updated on a yearly basis. Enhancements to modeling inputs and assumptions are constantly incorporated, based on the needs identified for the MISO footprint, new developments, industry best-practices, and stakeholder feedback.

Q. HOW HAS THIS MODEL PREVIOUSLY BEEN USED FOR MISO'S PRA?

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[14] *See* MISO's Resource Adequacy site, available at: https://www.misoenergy.org/planning/resource-adequacy2/resource-adequacy/#t=10&p=0&s=FileName&sd=desc

See MISO's Loss of Load Expectation Working Group site, available at: https://www.misoenergy.org/engage/committees/loss-of-load-expectation-working-group/

A. MISO has performed LOLE analysis using a probabilistic model for more than fifteen years, and has used the current software, SERVM, since 2015 in establishing Resource Adequacy Requirements (both PRMR and LRR). MISO's probabilistic model has also been used to perform the studies that determine the seasonal capabilities of wind and solar resources for the determination of requirements, as well as to accredit wind resources that plan to participate in the PRA. The proposed accreditation methodology will improve the alignment between accreditation and requirements in the MISO RA construct. MISO will continue to use the probabilistic model to set Resource Adequacy Requirements and will expand the use of the model to establish Resource Class-level UCAP.

Q. PLEASE EXPLAIN LOLE.

A. As discussed above, LOLE is the measure of how often, on average, the probabilistic model experiences days in which resource availability falls short of the load demand. LOLE is a commonly used metric in the electric industry, particularly in North America, to measure the expected frequency of resource adequacy events in a year, a season, or any other pre-defined period. As part of the LOLE analysis process, MISO calculates the following three probabilistic risk metrics:

- LOLE, which measures the frequency (in days) of load shed events;
- Loss of Load Hours (LOLH), which measures the expected number of hours per year expected to experience load shed events; and
- Expected Unserved Energy (EUE), which is an estimate of the energy that would otherwise have been used by end use customers but for a supply interruption during a predefined period (e.g., a year).

Q. PLEASE DISCUSS THE LOLE CRITERION TO WHICH MISO PLANS.

A. The MISO Resource Adequacy criteria for determining the Planning Reserve Margin Requirements is the industry-accepted LOLE objective of 1 day in 10 years on an annual basis. This LOLE criterion is also used by other ISOs, including NYISO and PJM, as discussed in their recent accreditation filings. Commencing with implementation of MISO's seasonal PRA in the Planning Year 2023-24, MISO evaluates LOLE for each Season and establishes corresponding seasonal Planning Reserve Margins. The seasonal LOLE analysis is determined as follows:

a) the system is adjusted until the annual LOLE reaches 1 day in 10 years;

b) the seasonal distribution of annual LOLE values is measured ;

c) any Season with a LOLE value below 0.01 is further adjusted until the LOLE in that Season reaches that value; and

d) any Season with a LOLE value at or above 0.01 receives the adjustment to capacity that drives that annual LOLE to 1 day in 10 years.

In the most recent LOLE analysis, most of the annual LOLE has been concentrated in the Summer Season, and all other Seasons had to be adjusted to meet the minimum of 0.01 LOLE.

Q. PLEASE DISCUSS THE LOLE MODEL INPUTS.

A. There are three broad categories of LOLE model inputs: load, generation resources, and system parameters. Load inputs consist of a demand and energy forecast, and load forecast errors. Generation inputs include operating parameters, unit forced outage rates, planned maintenance rates, hourly generation level for variable renewable resources, and dispatch

limits for demand response and interruptible load. System parameter inputs include zone and pool definitions, external tie limits, and external system energy imports.

Q. PLEASE DISCUSS HOW MISO MODELS LOAD IN ITS LOLE ANALYSIS.

A. MISO develops hourly load profiles that are used in the simulation of the probabilistic models. To ensure a representation of a wide range of system conditions, 30 load profiles are created, based on observed weather for the last 30 weather years, primarily driven by temperature values. The process to create the load data profiles can be summarized as follows:

MISO uses the previous 5 years of historical load data with Load Modifying Resource load reductions added back into the load, as an input to train a neural-net model to predict weather-correlated load shapes for each of these 30 weather years.

MISO also performs validations and corrections on the predicted neural-net load shapes to ensure proper load shape and peak values. This training allows the model to evaluate the risk that could materialize in the upcoming Planning Year if similar weather patterns were to be experienced again.

MISO applies the Zonal Coincident Peak Forecasts provided by the Load Serving Entities to develop zonal- and monthly-specific load forecast scaling factors which scale the average of the 30 load shapes based on provided forecasts.

This procedure creates hourly load profiles for the 30 weather years, which are consistent with expected load forecasts. During the LOLE simulations, each load profile is further adjusted to account for economic load uncertainty using economic load forecast error (LFE) scalars, resulting in five load profiles for each weather year. These include the expected load profiles, plus an increase of the load by ±1% and ±2%. Corresponding

probabilities are assigned to each load forecast error level, which are published by MISO every year. These probabilities can vary depending on the Planning Year. For example, the probabilities for Planning Year 2023-2024 were previously provided in Section IV. The 30 years of load data are also provided to Market Participants by MISO prior to the beginning of each Planning Year.

Q. PLEASE DISCUSS HOW MISO MODELS GENERATION IN ITS LOLE ANALYSIS.

A. MISO uses data from several different sources to model generation in its LOLE analysis. MISO begins with its annual, base Commercial Model and uses eligible capacity as determined by the annual PRA. Thermal units are modeled as must-run and perform at their full capacity whenever units are not on outage. The primary data source for forced outage rate statistics, planned maintenance statistics, and net dependable capacity (NDC) for monthly capacity profiles are obtained from the Generator Availability Data System (GADS).

Retirements are accounted for based upon the Attachment Y process in the MISO Tariff, while new resources are included based upon their position in the Generator Interconnection Queue. Imports are modeled based on firm capacity contracts from external areas to serve MISO load, as well as a probabilistic distribution of non-firm support from external areas.

MISO models wind and solar resources using hourly output profiles that reflect their variable nature. Each of the 30 weather years modeled have a unique hourly output for wind and solar resources to align with the load profiles which are described in more detail

below. Prior to each Planning Year, MISO shares the 30 weather years of hourly data for wind and solar resources with Market Participants.

Other renewable resources, like run-of-river and biomass are modeled at a flat capacity value.

Q. DOES MISO CONSIDER HOW COLD-WEATHER OUTAGES IMPACT GENERATION IN ITS LOLE ANALYSIS?

A. Yes, Astrapé, the entity that manages the SERVM software used for LOLE analysis, performed an analysis showing that as the temperatures decreased, the average megawatts (MW) of forced outages for coal and gas resources increases.[15] Based on that analysis, a MW/degree relationship was developed and modeled so that at each temperature, there is a specific MW amount of incremental cold weather outage captured for each zone. The incremental cold weather outages are not assigned to a particular resource but rather represent the aggregate Resource Class-level impact on the system to the Coal, Gas, and Combined Cycle Resource Classes.

Q. HOW ARE WIND RESOURCES SPECIFICALLY MODELED IN THE LOLE MODEL?

A. MISO models wind resources with hourly generation profiles for each of the 30 weather years. Profiles from 2013 and on use observed historical data, aggregated by LRZ. Minor increases to the profile are included from 2013 to 2015 to account for technology improvements as detailed in the Astrapé Seasonal Inputs Study.[16] Synthetic profiles are

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[15] Section 5 of the report available at 20220707 LOLEWG Supplemental MISO Seasonal Inputs Documentation Astrape625466.pdf (misoenergy.org).

[16] Astrapé Seasonal Inputs Study: Astrapé Seasonal Inputs Study.

generated for each LRZ and weather year prior to 2013 by choosing wind output from the observed days based on (a) the maximum daily temperature in the April through October months, and (b) the minimum daily temperature during November through March. The temperature to provide a match is aggregated at the LRZ level.[17]

Q. HOW ARE SOLAR RESOURCES SPECIFICALLY MODELED IN THE LOLE MODEL?

A. Solar generation profiles are created in a similar fashion to that for the wind resources. First, hourly irradiance data for sites across the MISO footprint are downloaded from the National Renewable Energy Laboratory's (NREL's) National Solar Radiation Database (NSRDB). The irradiance data is converted to hourly power generation data using NREL's System Advisory Model software. Given that the NREL irradiance data is only available starting with year 1998, data for prior weather years are developed by selecting daily solar profiles from the day that most closely matched the peak temperature out of all days ($\pm$ 6 days) from the available data.

Q. HOW ARE STORAGE RESOURCES MODELED IN THE LOLE MODEL?

A. Storage resources are treated as energy-limited resources in the LOLE model. Pumped storage resources are currently modeled with seasonalized forced outage rates, an annualized planned outage rate, and monthly capability. Electric Storage Resources have a

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[17] This matching procedure begins by matching a day prior to 2013 to the same calendar day for a year that is observed, where the matching occurs if the temperatures on the two dates are equal. If they are not equal, the previous and subsequent calendar date is evaluated. This continues until a band of $\pm$10 days has been searched. If no matches have occurred, the temperature is allowed to be different by 1°, and the search repeats. For example, for April 11th, 1998, the dates April 11th, 2013, April 11th, 2014, and so on are evaluated. If one of these days has the same max temperature as the 1998 year, then the wind profile from that matched day is used. If not, April 10th and April 12th are evaluated. This continues until a range encompassing April 1st through April 20th has been searched.

4-hour duration with a cycle efficiency of 85% and a maximum hourly output value determined by the capacity of the individual resource. Electric Storage Resources are dispatched in the model when load cannot be served by other resources (except emergency resources). The probabilistic model keeps track of the stored energy in these resources and will allow generation until the energy is exhausted. At that point, the storage resources will need to replenish its stored energy before they are available for dispatch in the model.

As a part of its LOLE modeling enhancements effort, MISO intends to continue working with stakeholders to evaluate how the modeling of storage resources in the LOLE model needs to be adjusted to reflect how they are being operated in the operational time frames or real time markets, and how their energy-limited nature may influence the determination of risk across simulated hours.

Q. HOW DOES MISO CONDUCT EXTERNAL SUPPORT MODELING FOR THE LOLE ANALYSIS?

A. Firm imports from the most recent PRA are included in the LOLE analysis and modeled as resources. In addition, MISO models non-firm imports as a probabilistic distribution based on historic imports from the most recent 3 planning years. As the model steps through the simulated hours, it randomly draws from this distribution of imports to serve the demand. Non-firm imports reduce the PRMR, which results in MISO relying on neighboring regions to serve some of its demand. Historic non-firm imports during historical Tier 2 RA hours are used to create a probabilistic distribution of non-firm support. This process is completed for each of the four Seasons to capture seasonal variability. As SERVM steps through the hourly Monte Carlo simulations, the model will randomly draw import values from seasonal distributions.

Q. WHY IS IT REASONABLE TO RELY ON THE CURRENT PROBABILITIC MODEL TO DETERMINE RESOURCE CLASS-LEVEL UCAP?

A. MISO has relied on a probabilistic model to determine the Resource Adequacy Requirements for over 15 years. Over that time, MISO has continually improved the underlying modeling and input data, incorporating best practices as they are developed by the industry and in collaboration with stakeholders. Use of MISO's current probabilistic model is therefore fully appropriate to be applied to the proposed DLOL-based accreditation methodology.

MISO is committed to further the evolution of the probabilistic model as this is both necessary and appropriate to better capture the changing composition of the Bulk Electric System and to continually improve the representation of the sources of system risk. MISO has communicated a plan to stakeholders to research, design, and implement specific aspects of the probabilistic model, including a revision of planned outages, cold-weather outages, load forecasting, and storage modeling.[18] The planned model enhancements will further refine that alignment between risk, needs, and availability, as will other additional improvements made in the future.

VI. DEVELOPMENT OF THE PROPOSED METHODOLOGY

Q. PLEASE PROVIDE AN OVERVIEW OF THE PROCESS MISO USED TO DEVELOP THE ACCREDITATION PROPOSAL THAT IS THE SUBJECT OF THIS FILING.

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[18] *See* 20240228 RASC Item 05c RA Model Enhancement Presentation631891.pdf (misoenergy.org)

A. In January 2022, following MISO's Seasonal Construct and SAC filing, MISO initiated a stakeholder process through the RASC to work with stakeholders to develop the resource accreditation reform that is the subject of this filing. MISO has followed the product development process shown in Figure 10 below. The goal of the product development process is to ensure the right solutions are built at the right time and solve the right issues. MISO began by defining the scope of the initiative, which included drafting a problem statement. Once the problem statement and scope were defined, MISO began evaluating potential solutions and ultimately recommended the proposed accreditation methodology that is the subject of this filing. From there, MISO began working through and refining the conceptual design. Once that process was complete, MISO made this filing with the Commission and, if accepted, will implement the proposed accreditation methodology for Planning Year 2028-2029. Pursuant to the proposed Schedule 53A, during the three-year period leading up to actual implementation, MISO will provide stakeholders with indicative information about expected Resource Class and resource level accreditation values to assist state regulators and LSEs with integrated resource planning.

Figure 10: MISO Product Development Process

Q. WHAT IS THE PROBLEM STATEMENT THAT MISO DEVELOPED IN COLLABORATION WITH THE STAKEHOLDERS AT THE BEGINNING OF THE ACCREDITATION REFORM EFFORTS?

A. The resource accreditation reform problem statement was first presented to stakeholders at the January 2022 RASC meeting. Stakeholders were provided an opportunity to comment on the problem statement, but generally agreed with it as presented. The problem statement has essentially remained the same and remains the focus of the resource accreditation reform effort. The problem statement is:

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's existing accreditation methods for non-thermal resources require further evaluation to ensure that the accredited capacity value reflects the capability and availability of the resource during the periods of highest reliability risk.

Q. WHAT IS THE SCOPE OF MISO'S RESOURCE ACCREDITATION REFORM EFFORT?

A. The scope of the accreditation reform as identified at the January 2022 RASC was to revisit the established accreditation practices for non-thermal resources with a priority focus on those with the greatest reliability impact in the near-term (i.e., wind and solar). In response to stakeholder feedback concerning comparability between resources and the Commission's comments in response to MISO's Seasonal Resource Adequacy Construct and SAC filing, MISO recommended extending the scope of the resource accreditation

reform effort to cover additional accreditation changes for all Capacity Resources (excluding external resources) at the January 2023 RASC.

Q. WHY DID MISO RECOMMEND EXTENDING THE SCOPE OF ACCREDITATION REFORM TO INCLUDE ALL CAPACITY RESOURCES AND NOT JUST NON-THERMAL RESOURCES?

A. The methodology developed for non-thermal resources was resource type agnostic and found to be applicable to all resources in the MISO footprint. This provided several advantages: (a) it does not discriminate based on resource type, which allows all Schedule 53A Resources to be treated equally, (b) it improves consistency and efficiency by bringing the entire accreditation process under one probabilistic modeling effort compared to many different methods under the existing process, (c) it provides alignment between the determination of the need (requirements) and availability of resources (accreditation) by ensuring both processes are performed with the same information and model, (d) it improves the thermal accreditation process by including new sources of risk, such as correlated and coincidental risks and weather-dependent derates, and (e) it allows for reliability-neutral substitution between resource types.

Q. WHAT WAS MISO'S APPROACH TO EVALUATING ACCREDITATION METHODOLOGIES?

A. MISO approached the evaluation of accreditation reform by examining a wide range of possible methods to address the problem statement. The evaluated methodologies for accreditation can be broadly divided into two categories: 1) average accreditation approach, such as average ELCC, and 2) marginal accreditation approach, which includes marginal ELCC, marginal reliability improvement (MRI) and DLOL. MISO developed

evaluation criteria and an analysis framework to compare modeling results and help guide decisions on which method was best for the MISO footprint. This larger list of options was ultimately reduced to a smaller set of three options that were examined in quantitative analysis and discussed with MISO stakeholders: ELCC method, a fully deterministic method, and blended method.

Q. WHAT CRITERION DID MISO CONSIDER WHEN EVALUATING ACCREDITATION METHODOLOGIES?

A. MISO evaluated accreditation methodologies against the following five general criteria: impact, feasibility, flexibility, stability, and, after receiving feedback from stakeholders, comparability. These were developed based on criteria previously used for the Resource Availability and Need (RAN) initiative, presented at the October 2020 RASC, and modified based upon stakeholder input. These criterion are all related to the "pillars of accreditation" identified by the Energy Systems Integration Group (ESIG).[19]

Q. PLEASE DISCUSS THE IMPACT CRITERION.

A. A method's impact is identifying and sufficiently mitigating actual risk under current and future portfolios and grid conditions in conjunction with markets and operations. Impact ensures sufficient capacity in the planning horizon when it's needed to maintain reliability. The method should measure performance in scarcity conditions and link planning to operations. This criterion is related to the reliability pillar identified by ESIG.

[19] Energy Systems Integration Group, "Ensuring Efficient Reliability: New Design Principles for Capacity Accreditation" (2023), available at: https://www.esig.energy/new-design-principles-for-capacity-accreditation/.

Q. PLEASE DISCUSS THE FEASIBILITY CRITERION.

A. Feasibility is the practicality, scalability, and ability of MISO and its Market Participants to implement the proposed methodology. The feasibility criterion also takes into consideration the clarity and transparency of the process. Both MISO and Market Participants need to be able to reasonably predict the expected accredited values of resources to ensure a reliable resource mix and make appropriate investment and retirement decisions. The feasibility criterion is rooted in the transparency pillar identified by ESIG.

Q. PLEASE DISCUSS THE FLEXIBILITY CRITERION.

A. Flexibility is a measure of how robustly a method holds up over time and responds to a changing system portfolio. As the resource portfolio evolves and technologies develop that change the load profile, an accreditation methodology needs to remain relevant and capable of properly accrediting resources. Without this flexibility, a system becomes in danger of mis-accrediting capacity values potentially leading to system reliability risks and an inefficient allocation of resources. This criterion is tied to the robust pillar identified by ESIG.

Q. PLEASE DISCUSS THE STABILITY CRITERION.

A. Stability is the ability to reasonably inform state and utility resource planning processes that rely on accreditation information as an input to long-term decision making. The method should not only remain robust under changing conditions but should be able to reflect changing conditions as system resource mix and load profiles evolve. Finally, these capacity values should remain predictable over time and only move when structural changes to the system have occurred which shift risk and alter the generation profile of the fleet. Greater volatility in capacity accreditation leads to lower investments as decision

makers face greater risk. A method that minimizes accreditation volatility increases investment certainty resulting in a more efficient system. This criterion aligns with the predictable pillar identified by ESIG.

Q. PLEASE DISCUSS THE COMPARABILITY CRITERION.

A. The comparability criteria refers to how comparable two different resource class accreditation values are to one another. Utility planners should be able to directly compare one resource class to another across a broad range of factors to make the most efficient investment and retirement decisions. A methodology that makes comparison between resource classes difficult may result in a less efficient and riskier resource portfolio. Conversely, a methodology that allows for comparability makes investment and retirement decisions easier to analyze and provides an accurate measure of the marginal cost and benefits associated with different amounts of different resource classes. This criterion is related to the non-discriminatory pillar identified by ESIG.

Q. PLEASE DESCRIBE THE ELCC METHOD.

A. The ELCC method belongs to a class of accreditation methodologies that determine capacity values based upon a probabilistic assessment of availability during loss of load hours. MISO analyzed two different types of ELCC methodologies. The first method, average ELCC, determines accreditation for each resource class by first modeling the system at the LOLE target criteria. Next, the resource class of interest is removed from the system and perfect capacity is added until the model returns to criteria. The amount of perfect capacity added is the accredited value of the class and referred to as the ELCC MW. This option is currently used at MISO for wind resources and served as the reference case. The second method, marginal ELCC, is identical in procedure to the average ELCC

approach, except instead of removing a resource class, an incremental resource is removed (or added) to the system.

Q. PLEASE DESCRIBE THE DETERMINISTIC METHOD CONSIDERED.

A. The deterministic method considered would have measured accreditation using only historical performance. This approach could take several forms, such as applying only the Schedule 53 Tier 1 and Tier 2 RA hours framework, relying upon historical GADS data, or some other strictly backward-looking approach based upon historical resource performance. This method is conceptually similar to how thermal units are currently accredited.

Q. PLEASE DESCRIBE THE BLENDED METHOD.

A. The blended method combines a probabilistic and deterministic approach. Each of the two approaches has its merits and shortcomings. A probabilistic approach allows for the expected capacity value of a resource to be estimated under a broad range of conditions. However, the quality of this assessment is limited by the standard modeling limitations, namely quality of the inputs and the model. Deterministic approaches have the advantage of demonstrating what has occurred and do not rely upon a model to calculate. Their drawback is that what happened yesterday may not accurately reflect what may happen tomorrow. If there are structural differences in events that are not captured, then a backwards-looking only framework may fail to properly realize the value of a resource and create improper incentives towards investment and retirement decisions.

The blended method attempts to merge these two perspectives into a single view and capitalize on each method's strengths while minimizing each method's weaknesses. With a blended method, accreditation would be based upon expected performance during

projected probabilistic risk periods as well as historical performance. Additionally, proper signals can be sent in both the operational and planning horizons by tying accreditation to both periods. Resource owners are rewarded for improving the operation of their units from the deterministic portion of the accreditation while sending more reliable signals about which assets to invest in or retire based upon the probabilistic portion.

Q. WHAT ACCREDITATION METHODOLOGY IS MISO PROPOSING?

A. MISO has chosen a blended approach combining a probabilistic approach, capacity values determined through the probabilistic modeling (the first step in the proposed DLOL-based methodology), with a deterministic approach, historical performance measured by the proposed Schedule 53A Tier 1 and Tier 2 RA hours for all Capacity Resources, excluding External Resources.

Q. WHEN WEIGHING THE IMPACT CRITERIA, EXPLAIN HOW MISO DECIDED TO RECOMMEND THE PROPOSED APPROACH.

A. MISO's proposed methodology identifies expected risk by accrediting resources during periods when the system is at highest risk, as measured by the margin between generation and load in the probabilistic model. The identification of these risky periods is independent of the resource portfolio. Because availability during Critical Hours is used to set Resource Class-level UCAP, the method naturally measures performance during scarcity conditions. Further, it also uses historical performance to establish capacity values and therefore incentivizes resources to perform in a manner that increases system reliability. Therefore, it links planning to operations and provides the greatest impact of the options considered.

Q. WHEN WEIGHING THE FEASIBILITY CRITERION, EXPLAIN HOW MISO DECIDED TO RECOMMEND THE PROPOSED APPROACH.

A. The proposed methodology uses a single probabilistic model run to set Resource Class-level UCAP and Resource Adequacy Requirements, limiting the computational complexity of the required calculations. It can be implemented in the same manner no matter the size of the resource portfolio, which gives it scalability. With similar input data, MISO and Market Participants could implement and replicate results. This feasibility allows for the ability for efficient investment and retirement decisions to be made with confidence that the projected accreditation values would be realized.

Q. WHEN WEIGHING THE FLEXIBILITY CRITERION, EXPLAIN HOW MISO DECIDED TO RECOMMEND THE PROPOSED APPROACH.

A. The proposed accreditation methodology will be applied to all Capacity Resources, except External Resources, in the same manner which gives it the flexibility needed to handle any resource portfolio composition. Therefore, as MISO's fleet evolves, the proposed accreditation methodology will inherently adapt to such changes. Moreover, MISO will continue to evaluate the efficacy of the DLOL-based methodology and continue discussions with stakeholders about potential enhancements going forward.

Application of the proposed accreditation methodology to all Capacity Resources, except External Resources, contrasts with the current accreditation methodologies, which are not robust enough to account for significant changes to the generation fleet. Lastly, as electrification and technological progress alters the shape of the load profile, the methodology will remain robust and provide a proper measure of the high-risk hours. Therefore, the proposed methodology satisfies the flexibility criterion as it is sufficiently robust to change in both load and generation.

Q. WHEN WEIGHING THE STABILITY CRITERION, EXPLAIN HOW MISO DECIDED TO RECOMMEND THE PROPOSED APPROACH.

A. It is important to have stability in the results. Accrediting a resource using only historical performance may subject it to significant shifts in its final accredited value, and worse off, may be lagging in representing the operational risk being experienced. By using a probabilistic model to measure the expected performance of a resource during critical hours, the method provides stability and certainty that resource accreditation will not suddenly decrease. Conversely, a method that focuses only on future expected performance could also subject a resource to dramatic shifts in capacity values if there is a significant shift in system risk. Therefore, a method that uses both historical performance and expected future performance attenuates any large shifts providing stability of accredited values. Finally, because the model is portfolio agnostic, the addition or subtraction of a set of resources will not have significant effects on existing resources, ensuring stability of capacity values for existing resources even as other Market Participants make investment decisions.

Q. WHEN WEIGHING THE COMPARABILITY CRITERION, EXPLAIN HOW MISO DECIDED TO RECOMMEND THE PROPOSED APPROACH.

A. The proposed methodology satisfies the comparability criterion by calculating accredited values for each type of Capacity Resource, except External Resources, in an identical manner. This means that a MW of accredited capacity from one type of resource can be substituted for a MW of accredited capacity from another resource without fear of the capacity values changing. Therefore, resource owners and Market Participants can directly make a cost-benefit calculation without requiring any additional calculations. This reduces

the uncertainty of investments leading to a more efficient resource portfolio. This also ensures a technology agnostic capacity valuation ensuring a non-discriminatory result.

Q. PLEASE DISCUSS THE KEY DIFFERENCES BETWEEN MARGINAL ELCC AND AVERAGE ELCC.

A. Average accreditation approaches (including average ELCC) accredit the entire class of a resource based on the contribution of the entire fleet of that class of resources, while marginal accreditation approaches measure the contribution of the next incremental addition to the resource class. By utilizing a marginal addition to the system, the marginal ELCC approach better captures how that incremental resource contributes to the needs of the system at criteria. This concept aligns with the assumption that capacity exchange in the capacity market is fungible and aligns best with something the average ELCC method is not able to provide.

VII. IMPACTS OF THE PROPOSED METHODOLOGY TO OTHER ASPECTS OF THE PRA

Q. BRIEFLY DESCRIBE HOW THE PRMR IS CURRENTLY DETERMINED.

A. The PRMR for each Season is determined as the sum of UCAP values for all resources, plus the MW adjustment to drive the probabilistic model to criteria in that Season. The current determination of UCAP values relies on a combination of accreditation methods, including EFORd based UCAP for thermal resources, seasonal capabilities for LMRs, contracted MW for firm External Resources, and average ELCC for wind and solar resources as shown in Figure 11 below.

Resource Type	Current method to establish capacity for PRMR*
Thermal	GVTC * (1 – Seasonal EFORd)
Wind/Solar	Effective Load Carrying Capability (ELCC)
Run-of-River/Biomass	Hourly output during peak hours
Storage	GVTC * 95% or hourly output during peak hours
Demand Response	Seasonal capability and # of calls
BTMG	GVTC* (1 – Seasonal EFORd)
External Resources	Firm external seasonal capability

*July for Summer, September for Fall, January for Winter and May for Spring

Figure 11: Overview of current methods for PRMR calculation

Q. PLEASE DESCRIBE HOW MISO IS PROPOSING TO CHANGE THE DETERMINATION OF PLANNING RESERVE REQUIREMENTS.

A. MISO is proposing to maintain the calculations of the PRMR and simply account for the determination of UCAP for Schedule 53A Resources, based on the proposed accreditation method. The PRMR will be determined as the sum of accredited values for all Schedule 53A Resources, Load Modifying Resources, Firm External Resources, within the LOLE model plus the MW adjustment to drive the probabilistic model to the LOLE target. As shown in Figure 12 below, MISO expects the seasonal PRMR to decrease under the proposed DLOL-based methodology compared to current season PRMR due to the

expected reduction in Resource Class-level accreditation. This result is further discussed in the Affidavit of Dr. Patton.[20]

MISO's current accreditation methodologies are misaligned with a resource's marginal contribution to reliability risk leading to over-accrediting and similarly results in higher PRMR that increases total cost to maintain Resource Adequacy at the target. The proposed accreditation method will improve alignment between accreditation and PRMR, lower PRMR and result in more efficient market outcomes.

PY 23/24 - PRMR	Summer		Fall		Winter		Spring		Formula Key
Resource Class	Current	Proposed	Current	Proposed	Current	Proposed	Current	Proposed	
Gas	30,251	29,541	28,595	29,745	28,582	23,605	28,962	23,657	[A]
Combined Cycle	27,558	27,326	28,635	27,015	28,552	23,650	27,929	22,997	[B]
Coal	40,545	39,955	39,888	38,812	39,914	32,539	39,280	32,641	[C]
Hydro (includes diversity contracts)	2,120	2,122	2,104	2,118	926	916	1,350	1,287	[D]
Nuclear	11,410	10,850	11,522	10,304	11,627	10,493	11,063	9,640	[E]
Pumped Storage	2,530	2,523	2,345	2,504	2,299	1,216	2,359	1,763	[F]
Storage	28	28	28	28	54	52	55	55	[G]
Solar	2,151	1,700	1,603	1,937	698	188	1,824	2,221	[H]
Wind	4,639	2,731	5,993	3,859	11,389	4,477	6,500	4,601	[I]
Run-of-River	966	966	966	966	966	966	966	966	[J]
BTMG	4,196	4,196	4,218	4,218	4,163	4,163	4,240	4,240	[K]
Demand Response	7,397	7,397	7,041	7,041	5,388	5,388	6,280	6,280	[L]
Firm External Support	1,707	1,707	1,714	1,714	1,857	1,857	1,778	1,778	[M]
Adj. {1d in 10yr}	(4,000)	(4,000)	(10,000)	(10,000)	(6,200)	(6,200)	(12,750)	(12,750)	[N]
PRMR	**131,498**	**127,042**	**124,652**	**120,261**	**130,215**	**103,310**	**119,836**	**99,376**	[O]= sum of [A] through [N]

Figure 12: Comparison of Current PRMR vs Proposed PRMR

Q. PLEASE DESCRIBE HOW MISO CURRENTLY CALCULATES LRR.

A. The calculation of LRR is similar to that of the PRMR, wherein the capacity is accounted for in the same way, but each LRZ is modeled independently without support from other

[20] IMM Affidavit at P 26.

LRZs or external areas, and each LRZ has its own MW adjustment to reach the seasonal LOLE criteria. Each LRZ's LRR MW is divided by the corresponding modeled zonal coincident peak forecast (LRZ load at the time of MISO's Coincident Peak Demand) to determine the LRR % that is applied to the updated LSE load forecasts for the PRA. This establishes each LRZ's LRR MW for the PRA.

Q. PLEASE DISCUSS HOW MISO PLANS TO CALCULATE LRR USING THE PROPOSED METHODOLOGY.

A. Like PRMR, LRR calculations are being updated to use accreditation by Resource Class as determined by the DLOL-based methodology. The overall approach will remain unchanged. The LRR for each LRZ is determined by aggregating the capacity accreditation of the resources in the Zone, plus a MW adjustment used to bring the LOLE model of the isolated LRZ to criteria.

As is the case with the PRMR, the main difference introduced in this proposal is the capacity accreditation for the internal resources in each LRZ (excluding LMRs). Ideally, the LRR would be determined by aggregating the final SAC values of all resources in an LRZ. However, those two values are determined at different points in time. LRR values need to be finalized in November prior to the Planning Year and final SAC values are not determined until the following February 15.

Given these scheduling challenges, MISO will produce LRR with an approximation of the final resource SAC values by combining data of the current and previous Planning Years, as follows:

1. The total Resource Class-level UCAP are determined for the current Planning Year (same values used to determine the current Planning Year PRMR).

2. Resource Class-level UCAP will be allocated to individual resources in the Resource Class using the Proposed Schedule 53A logic described earlier but utilizing the ratio of individual resource's ISAC to the corresponding Resource Class ISAC from the previous Planning Year. This provides estimated SAC values for individual resources that will only be utilized for LRR calculations.

3. The estimated SAC values are aggregated to the LRZ level, and that value is used as an input into the LRR calculations, similar to how the current method utilizes UCAP, average ELLC, or established capacity for thermal, wind, and solar resources, respectively.

Because the Schedule 53A process proposes to use the previous three years to determine Tier 1 and Tier RA 2 hours, the current and previous Planning Years, should have an overlap equal to two thirds of the hours. These should ensure a reasonable alignment between preliminary estimated and final SAC values at both the resource and LRZ levels. MISO presented an illustrative example of a system with two LRZs and four resources at the February 28, 2024 RASC meeting to explain proposed methodology for LRRs.[21]

Q. PLEASE DESCRIBE HOW MISO ALLOCATES PRMR TO INDIVIDUAL LOAD SERVING ENTITIES TODAY.

---

[21] See Slides 11-12 of the MISO accreditation presentation from Feb 28th RASC meeting.

A. Through the probabilistic analysis, MISO establishes PRMR for each Season for an LSE's Load within any given LRZ. The seasonal PRMR values are converted to a Planning Reserve Margin (PRM) percentage by subtracting the modeled seasonal Coincident Peak Demand from the PRMR and dividing by the modeled seasonal Coincident Peak Demand. The PRMR used in the PRA is set by applying the seasonal PRM percentage determined from the previous step plus a transmission loss percentage to the LSE-submitted updated Coincident Peak Forecasts. MISO uses PRM % as established through the process described above and in Figure 13 unless an alternate PRM is established by a state regulatory authority. In such an event, MISO will use the alternate PRM set by the state regulatory authority for the geographic area in its jurisdiction. MISO converts any state regulatory authority provided PRM to a comparable UCAP basis.

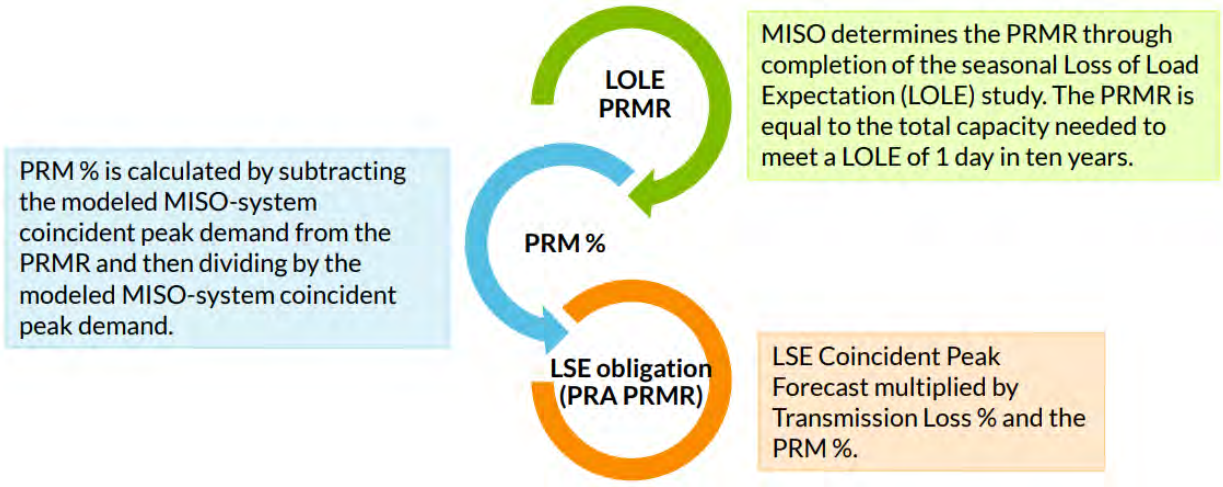

Figure 13: PRM % for Planning Resource Auction

Q. DOES MISO ADDRESS THE ALLOCATION OF PRMR TO LOAD SERVING ENTITIES WITHIN THIS FILING?

A. No. MISO is not proposing any change to the process of allocating PRMR to Load Serving Entities (LSEs) within this filing. MISO initiated stakeholder discussion on allocation of

PRMR in 2023 and concluded that any changes to the allocation process will require deliberate and careful considerations regarding substantive changes that may be needed to the processes and potentially to the systems used by LSEs to submit load forecast data to MISO. The current allocation methodology has been deemed by FERC to be just and reasonable and MISO is not proposing any changes to it. And as noted above, the proposed DLOL-based methodology will improve alignment between resource accreditation and establishment of the PRMR.

Q. DOES MISO PLAN TO ADDRESS THE ALLOCATION OF PRMR IN THE FUTURE?

A. Yes. MISO has already started conversations with stakeholders to transition from today's allocation mechanism that purely relies on the contribution to MISO's seasonal Coincident Peak Demand. MISO will consider alternative mechanisms that also incorporate recognition that risk periods in the future may not solely be determined by times of high load, as drivers of risk evolve over the next decades. MISO will evaluate these allocation mechanisms against a comprehensive set of criteria, which will be used, along with stakeholder discussions and input, to develop a final design for any future changes to how the PRMR is allocated.

Q. HOW DOES MISO'S RESOURCE CLASS-LEVEL UCAP (DLOL-BASED METHODOLOGY) ALLOW ALIGNMENT BETWEEN ACCREDITATION AND RESOURCE ADEQUACY REQUIREMENTS?

A. Under the proposed methodology, the Resource Class-Level UCAP becomes an input to the determination of PRMR and LRR. Accreditation and Resource Adequacy Requirements under the proposed accreditation methodology are determined based on the

same probabilistic model simulation and hours, increasing consistency in the process and alignment between system risks, needs, and accreditation. This improves the current situation where accreditation is separated across three different, distinct processes for thermal, wind, and solar resources, which is currently disconnected between how capacity is accounted for in the requirement calculations.

Q. HOW WILL THIS SEND THE RIGHT SIGNALS TO INVEST IN THE RIGHT MIX OF RESOURCES NEEDED TO MAINTAIN RELIABILITY IN THE MISO FOOTPRINT?

A. The proposed accreditation methodology aligns the times of system risk and need with the contribution of each Resource Class during those same periods. By consistently applying this approach to all Resource Classes, Market Participants will be able to compare how each Resource Class's ability to contribute to resource adequacy changes over time and continue to find the right balance to ensure system reliability. These signals will be complemented with forward-looking estimates for Resource Class accreditation values, which are described in Section IX.

Q. WHAT IMPACT DOES MISO'S RELIABILITY BASED DEMAND CURVE (RBDC) PROPOSAL HAVE ON THE INSTANT FILING?

A. There is no change to the RBDC proposal because of the proposed accreditation reforms. The seasonal Planning Reserve Margin Requirements, that act as the starting point of the Marginal Reliability Impact (MRI) Curve calculations, will be based on the Resource Class-level UCAP as determined through the proposed DLOL-based methodology as described above.

VIII. STAKEHOLDER ENGAGEMENT

Q. HAS MISO SOLICITED AND CONSIDERED STAKEHOLDER INPUT IN DEVELOPING THE PROPOSED ACCREDITATION METHODOLOGY?

A. Yes, MISO's proposed accreditation methodology is based on robust stakeholder discussions over the last two years (Figure 14). The stakeholder discussions on accreditation reforms began in January 2022 following Tariff filings for reforms to thermal resource accreditation and seasonal Resource Adequacy construct. As described in Section VI above, MISO used its product development process to frame the issue or problem statement and evaluate options throughout 2022. In November 2022, MISO recommended the proposed two-step accreditation methodology for wind and solar resources. At the January 2023 RASC, MISO recommended extending the scope of the accreditation reform effort to cover accreditation changes for all Capacity Resources, except External Resources. One of the main reasons for this extension of scope was the stakeholder feedback to have a uniform accreditation methodology for all resources. Subsequently, throughout 2023 and in early 2024, MISO engaged stakeholders at the RASC and solicited their input to develop a detailed design for the proposed methodology.

Figure 14: Accreditation Reform Stakeholder Engagement Timeline

Q. DID MISO CHANGE ITS PROPOSED DESIGN TO ADDRESS STAKEHOLDER FEEDBACK?

A. MISO has made several improvements to its accreditation proposal based on feedback provided as a part of the stakeholder process. Stakeholder discussion and feedback played a substantial role in shaping the design of the accreditation reform proposed herein.

As discussed earlier, the initial scope of the instant accreditation reform included non-thermal resources including solar and wind resources. Stakeholders provided feedback and MISO agreed that accreditation across all fuel types should be comparable. In response to this feedback and to bring resources under the same accreditation methodology, MISO extended the scope of the accreditation reform to apply to all applicable Capacity Resources. This change, in response to stakeholder feedback, provides improved and consistent accreditation across resources of different fuel types.

Stakeholders also had concerns that basing accreditation on only modeled loss of load hours may not adequately account for reliability risks. Feedback from stakeholders suggested that MISO expand the hours considered in the DLOL-based methodology to include additional hours with increased reliability risk. After evaluation, MISO agreed with stakeholders that relying on only loss of load hours could result in scenarios where reliability risks during hours, when available generation is just sufficient to meet the demand (e.g., total available generation is 50 MW above load in a given hour), is not captured in the calculation. Additionally, relying on only loss of load hours could also result in year-over-year volatility especially when the number of loss of load hours in a particular Season is smaller. Upon consideration, MISO expanded its definition of Critical

Hours to include additional low margin hours in addition to loss of load hours. The expanded Critical Hours provides stability improvements to the resulting accreditation.

Along with expanding hours, MISO also considered Stakeholder feedback that modeled results should be weighted by expected unserved energy (EUE) in the probabilistic model that would weight results by the severity of modeled risk. Although the MISO design team was in favor of weighting hours by severity of risk, using only EUE to weight results would provide weight for only loss of load hours, giving any low margin hours no weight at all. To provide both weighting and consideration of expanded hours, the weighting methodology proposed above provides the most weight to the hours with the greatest reliability risk and provides comparable weights to hours with similar risk around the loss of load threshold.

Although occurring late in the design process, Stakeholder feedback helped shape the Local Resource Requirement design provided above. The revised LRR design proposal is a result of substantial opposition to the originally proposed design. In response to this overwhelming opposition, the MISO design team crafted a new LRR proposal. The resulting positive stakeholder feedback suggests that the revised approach described above is the right balance within the proposed accreditation reform.

Throughout the Stakeholder process, the feedback was clear that there was a need for better understanding of the probabilistic model. To help stakeholders better understand MISO business practices around LOLE modeling and probabilistic analysis, MISO hosted a LOLE modeling and Accreditation Reform workshop for stakeholders in September

2023.[22] As a part of stakeholder process for the proposed accreditation reforms, MISO and stakeholders discussed and agreed that LOLE modeling improvements are important to align the probabilistic model with the expected operation of resources. As discussed further below, improving and enhancing the probabilistic model is an iterative and ongoing process. In response to extensive stakeholder feedback, MISO has recently kicked off a formal stakeholder process for LOLE modeling enhancements.

Stakeholders also voiced concerns about the timing for implementation of the proposed accreditation methodology. Among other concerns, stakeholders noted that resource planning and investment decisions are already being implemented and that sufficient time is needed before applying the new accreditation methodology in the Planning Resource Auction. In response to this stakeholder feedback, MISO is proposing the three-year transition period described below. In addition, MISO is committed to providing stakeholders with indicative information about the impact of the proposed changes both during the transition period and going forward.

Q. WHAT ARE MISO'S PLANS AND COMMITMENTS TO IMPROVING THE PROBABILISTIC MODEL?

A. As described above, the Resource Class accreditation values established through the proposed methodology are a direct outcome from the probabilistic model. It is important to note that MISO regularly evaluates its LOLE process to determine whether enhancements can be implemented to reflect changing system conditions more accurately. Recent improvements that have been made to the probabilistic model include the addition

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[22] *See* MISO's LOLE Modeling & Accreditation Reform Workshop - September 22, 2023 (misoenergy.org)

of a cold-weather outage adder, use-limited modeling of Electric Storage Resources, renewable profiles, inclusion of a probabilistic distribution of non-firm external support, and the addition of seasonal forced outage rates. This is an ongoing process that is necessary to help ensure the LOLE results are consistent with the underlying risk parameters. MISO is committed to continuing this process of enhancing the probabilistic model to better reflect risks across the year. Any future changes to the probabilistic model to better reflect risk will then be reflected in both the Resource Adequacy Requirements and accreditation values. Improving the probabilistic model is the best way to capture risk more accurately, which will better reflect the contribution to reliability of the resources modeled. As mentioned previously in Section V, MISO has communicated a plan to stakeholders to research, design, and implement specific aspects of the probabilistic model, including a revision of planned outages, cold-weather outages, load forecasting, and storage modeling. For example, through several discussions with stakeholders, MISO recognizes that SERVM may not currently distribute planned outages consistently across Resource Classes which may have inadvertent impacts on Resource Class-level UCAP. MISO has already initiated discussions at the RASC to further investigate this potential issue and address it as needed prior to implementation. The planned model improvements will further refine alignment between risk, needs, and availability, as will further improvements performed in the future.

Q. IS MISO COMMITTED TO IMPROVING STORAGE DISPATCH MODELING?

A. Starting with Planning Year 2024-2025, MISO started representing Electric Storage Resources with SERVM's native model for energy-limited resources. MISO is planning to simulate future-looking cases, with increased penetration of storage to better understand

how the advent of these resources affect the probabilistic model results and the distribution of risk in the MISO footprint in the future.

Q. WHAT IS MISO DOING TO PROVIDE MORE TRANSPARENCY REGARDING THE DATA AND INPUTS TO THE PROBABILISTIC MODEL?

A. MISO currently makes available to stakeholders many of the inputs to the probabilistic model, e.g., shapes for 30 years of load, wind, and solar, as well as documents the development process for other inputs.[23] Throughout the stakeholder engagement period, MISO has produced Resource Class estimates for the proposed accreditation methodology under a variety of assumptions and configurations, as well as the resulting impacts on PRMR and LRR values. MISO has also shared with individual Market Participants their specific resource-level estimates.

Additionally, MISO has engaged with stakeholders on several occasions to explain the current limitations, including specific data items, that prevent MISO from sharing the probabilistic model and has requested feedback to overcome said limitations. MISO's Tariff, however, prohibits MISO from sharing resource-specific information, which is the property of the various Market Participants, including outage rates and granular load forecasts without express approval from all Market Participants. MISO has initiated conversations at the January and February 2024 RASC meetings to improve upon data transparency.[24] MISO is committed to establishing a new process to provide additional data

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[23] *See* Astrapé Consulting: *MISO Seasonal Inputs for the 2022 LOLE Study* available at: https://cdn.misoenergy.org/20220707%20LOLEWG%20Supplemental%20MISO%20Seasonal%20Inputs%20Documentation%20Astrape625466.pdf

[24] See LOLE Model Data Transparency, February 28, 2024 RASC available at: https://cdn.misoenergy.org/20240228%20RASC%20Item%2005b%20LOLE%20Data%20Transparency631895.pdf

annually to stakeholders related to the probabilistic model's generation inputs while continuing to share shapes for 30 years of load, wind and solar. The additional data will be masked, rolled up, or provided with class averages so that stakeholders can replicate results while maintaining data confidentiality, consistent with the requirements of its Tariff and recent stakeholder feedback.

IX. TRANSITION PERIOD AND IMPLEMENTATION TIMELINE

Q. WHAT EFFECTIVE DATE HAS MISO REQUESTED FOR THE RESOURCE ACCREDITATION REFORM PROPOSAL?

A. MISO has requested an effective date of September 1, 2024, for the reporting requirement included in the Tariff. Pursuant to the proposed Tariff Schedule 53A, beginning September 1, 2024, MISO will be required to publish Resource Class-level indicative results and provide resource-level indicative results by Market Participant to individual resource owners as requested prior to the PRA beginning with the 2025 PRA for Planning Year 2025 – 2026 and continuing for the next two Planning Years.

Q. WHEN DOES MISO PLAN TO IMPLEMENT THE PROPOSED ACCREDITATION METHODOLOGY?

A. MISO plans to use the proposed accreditation methodology to accredit resources beginning with the 2028 PRA for Planning Year 2028 – 2029 (Figure 15). During the three-year transition period, beginning with Planning Year 2025 – 2026, MISO will provide resource-level results as requested to Market Participants using the proposed methodology so that they understand the impact on their resources prior to implementation.

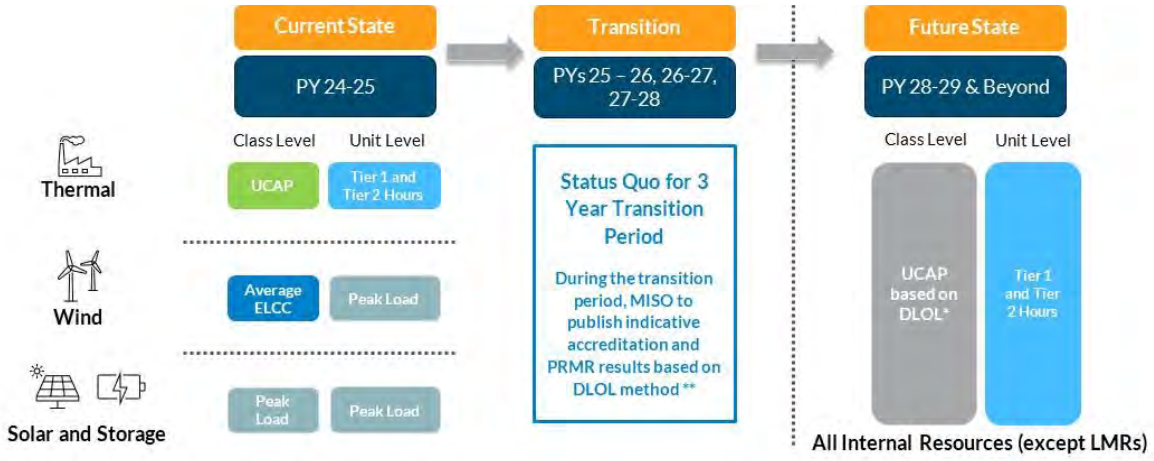


Figure 15: Effective Date and Transition Plan shared with stakeholders

Q. WHY HAS MISO CHOSEN A SEPTEMBER 1, 2024 EFFECTIVE DATE GIVEN IT DOES NOT INTEND TO IMPLEMENT THE PROPOSED METHODOLOGY UNTIL PLANNING YEAR 2028 – 2029?

A. The three-year transition period is an important aspect of the overall proposal and, as discussed above, was developed to address stakeholder concerns regarding implementation timing. MISO recognizes that the change in the accreditation methodology is a significant one and has designed the transition period to provide Market Participants an opportunity to adjust to the change. This transition period will assist LSEs with integrated resource planning by equipping them with the data they need to make long-term investment decisions.

Q. HOW WILL MISO PROVIDE INDICATIVE RESULTS TO STAKEHOLDERS DURING THE TRANSITION PERIOD?

A. For each of the Planning Years during the transition period, MISO will provide indicative results for the proposed accreditation methodology. The Resource Class-level UCAP, PRMR, and LRR estimates will be made available to stakeholders and will be based on the same probabilistic model simulation results used to determine the PRMR in that Planning

Year. Market Participants will also be provided with the indicative Schedule 53A SAC values for their own resources as requested. Indicative results will be generated concurrent with existing processes and MISO will produce them as soon as feasible.

Q. HOW WILL MISO PROVIDE FORWARD-LOOKING RESOURCE ACREDITATION ESTIMATES?

A. To assist LSEs with integrated resource planning needed to make long-term investment and retirement decisions, MISO will provide future year (5 and 10 year forward) estimated Resource Class-level accreditation values annually as part of MISO's Renewable Resource Assessment (RRA) study starting in 2024. Additional data needs and sensitivities will be considered as these estimates are developed. Just as with all future predictions, the degree of uncertainty in the inputs alone (future demand growth, change in consumer behavior, future generation technologies, rate of retirements and deployment, etc.) can substantially vary the outcome of RA needs and LOLE analysis for such long timeframes.

Q. HOW WILL RESOURCES BE ACCREDITED DURING THE TRANSITION PERIOD?

A. The transition proposal includes keeping the status quo accreditation methodologies for all resource types until PY 2028-2029. Following the transition period, MISO intends to apply the proposed accreditation methodology to all Capacity Resources including thermal, wind, solar and Electric Storage Resources.

X. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Affidavit of Zakaria Joundi

COUNTY OF HAMILTON)
)
STATE OF INDIANA)

Zakaria Joundi, being duly sworn, deposes and states that he prepared the Prepared Direct Testimony of Zakaria Joundi, and the statements contained therein are true and correct to the best of his knowledge and belief.

Zakaria Joundi

SUBSCRIBED AND SWORN BEFORE ME, this 27 day of March, 2024.

Rhiannon Rena Shelley
(*Notary Public Signature*)

Commissioned in Clinton county.
Commission Number: 705772
Commission Expires: 9/27/2025

RHIANNON RENA SHELLEY
Clinton County
My Commission Expires
September 27, 2025

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

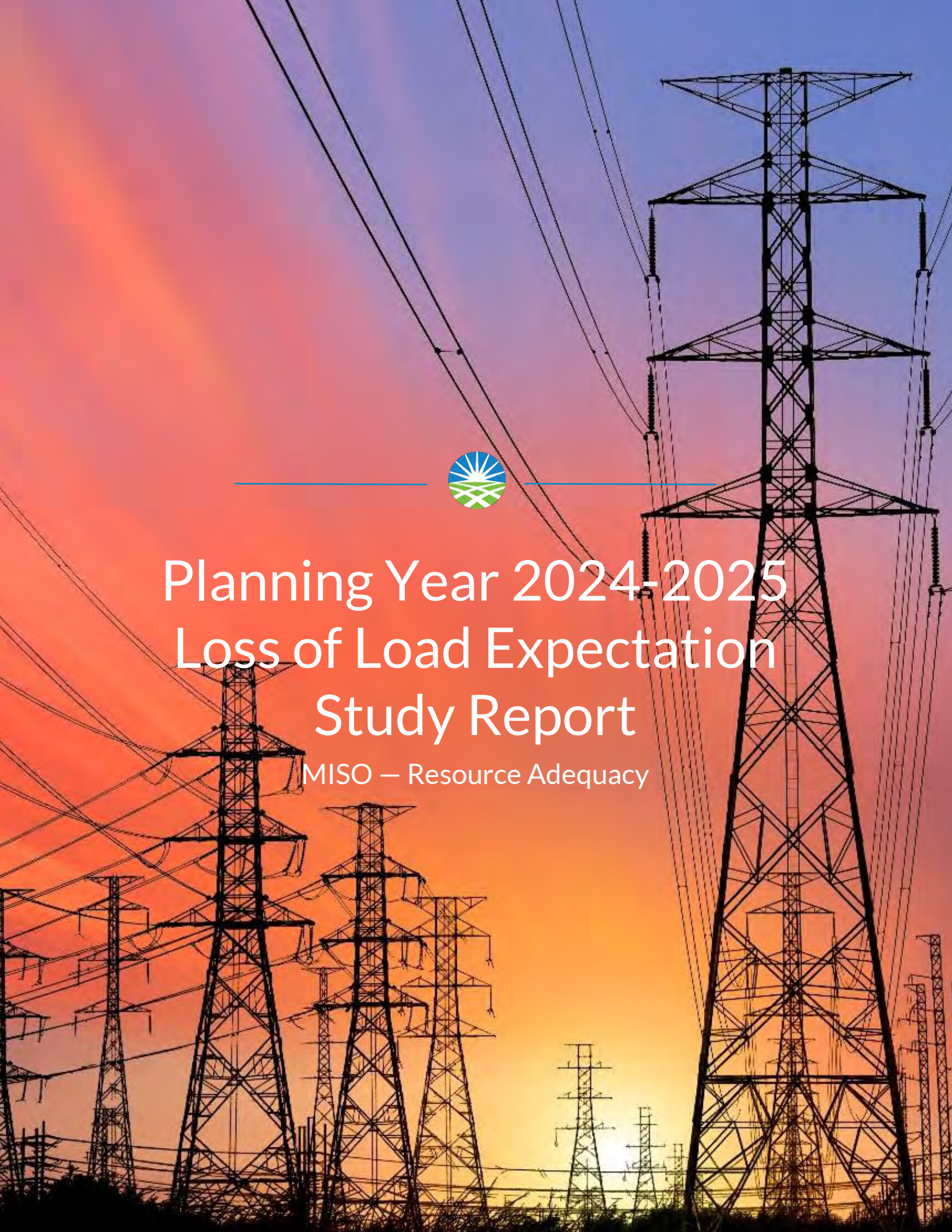
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-7

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

Filed September 5, 2025

Exhibit 82

MISO 2024-25 LOLE Study Report



Planning Year 2024-2025 Loss of Load Expectation Study Report

MISO — Resource Adequacy

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April 2024 Update: Outyear Planning Reserve Margin (PRM) and additional EFORd results added to report.

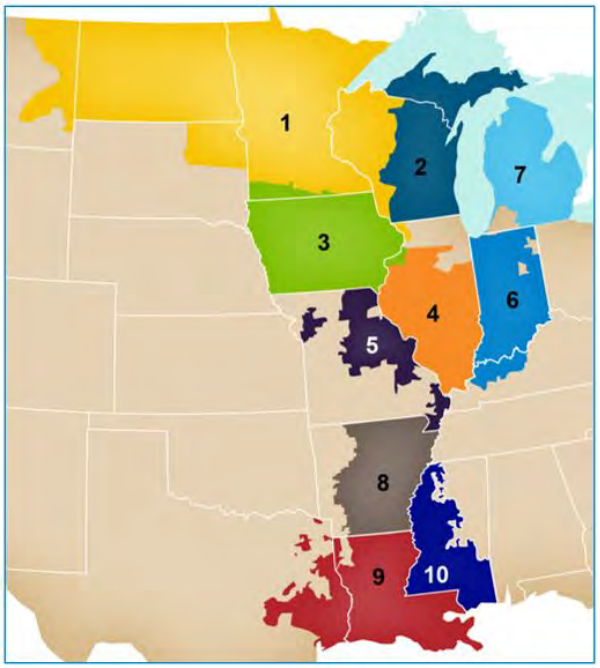
Executive Summary

In preparation for the annual Planning Resource Auction, MISO conducts an annual Loss of Load Expectation (LOLE) study to determine Resource Adequacy Requirements for the upcoming Planning Year 2024-2025. These requirements are identified on a seasonal basis for each Local Resource Zone within MISO.

Planning Reserve Margin (PRM) determined through this year's study are:

Season	PRM UCAP %
Summer 2024	9.0%
Fall 2024	14.2%
Winter 2024-2025	27.4%
Spring 2025	26.7%

MISO is divided into ten Local Resource Zones (LRZs) as shown in the figure below.



Local Resource Zone	Local Balancing Authorities
1	DPC, GRE, MDU, MP, NSP OTP, SMP
2	ALTE, MGE, MIUP, UPPC, WEC, WPS
3	ALTW, MEC, MPW
4	AMIL, CWLP, GLH, SIPC
5	AMMO, CWLD
6	BREC, CIN, HE, HMPL, IPL, NIPS, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	EMBA, SME

The report also determines zonal Local Reliability Requirements (LRRs). Additionally, initial values for zonal Capacity Import Limits (CIL), Capacity Export Limits (CEL), Zonal Import Ability (ZIA), and Zonal Export Ability (ZEA) for each season are also determined. These quantities are described in section 2.3.

Tables ES-1 through ES-4 below show results for each season.

PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
Summer 2024 PRM UCAP	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%
LRR UCAP per-unit of LRZ Peak Demand	1.132	1.113	1.278	1.291	1.331	1.190	1.161	1.392	1.135	1.518
Capacity Import Limit (CIL) (MW)	6,462	4,506	5,009	10,790	3,208	7,463	4,500	3,536	5,613	3,564
Capacity Export Limit (CEL) (MW)	4,537	3,971	5,450	2,730	4,644	5,637	5,709	6,171	2,359	1,840
Zonal Import Ability (ZIA) (MW)	6,460	4,506	4,911	9,857	3,208	7,197	4,490	3,444	4,794	3,564
Zonal Export Ability (ZEA) (MW)	4,539	3,971	5,548	3,663	4,644	5,903	5,719	6,263	3,178	1,840

Table ES-1: Initial Planning Resource Auction Deliverables — Summer 2024

PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
Fall 2023 PRM UCAP	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%
LRR UCAP per-unit of LRZ Peak Demand	1.235	1.199	1.345	1.323	1.441	1.257	1.311	1.496	1.190	1.667
Capacity Import Limit (CIL) (MW)	6,502	5,719	6,789	6,637	3,786	8,954	4,400	5,040	6,435	4,736
Capacity Export Limit (CEL) (MW)	5,711	4,512	6,913	3,863	5,402	3,519	5,381	4,212	3,602	2,889
Zonal Import Ability (ZIA) (MW)	6,500	5,719	6,684	5,699	3,786	8,661	4,390	4,942	5,608	4,736
Zonal Export Ability (ZEA) (MW)	5,713	4,512	7,018	4,801	5,402	3,812	5,391	4,310	4,429	2,889

Table ES-2: Initial Planning Resource Auction Deliverables — Fall 2024

PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
Winter 24-25 PRM UCAP	27.4%	27.4%	27.4%	27.4%	27.4%	27.4%	27.4%	27.4%	27.4%	27.4%
LRR UCAP per-unit of LRZ Peak Demand	1.442	1.363	2.006	1.338	1.285	1.227	1.607	1.560	1.328	1.864
Capacity Import Limit (CIL) (MW)	4,693	5,523	5,704	6,731	4,477	8,526	4,666	4,336	5,420	3,219
Capacity Export Limit (CEL) (MW)	5,174	4,772	8,975	4,650	6,229	1,407	5,743	5,808	2,103	2,993
Zonal Import Ability (ZIA) (MW)	4,691	5,523	5,600	5,811	4,477	8,286	4,656	4,262	4,623	3,219
Zonal Export Ability (ZEA) (MW)	5,176	4,772	9,079	5,570	6,229	1,647	5,753	5,882	2,900	2,993

Table ES-3: Initial Planning Resource Auction Deliverables — Winter 2024-2025

PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
Spring 2024 PRM UCAP	26.7%	26.7%	26.7%	26.7%	26.7%	26.7%	26.7%	26.7%	26.7%	26.7%
LRR UCAP per-unit of LRZ Peak Demand	1.329	1.363	1.531	1.662	1.618	1.371	1.322	1.610	1.334	1.878
Capacity Import Limit (CIL) (MW)	4,943	5,034	6,626	6,003	3,892	8,015	4,893	6,124	6,417	4,628
Capacity Export Limit (CEL) (MW)	6,318	4,601	5,761	5,081	4,984	3,444	5,591	4,936	3,994	2,740
Zonal Import Ability (ZIA) (MW)	4,941	5,034	6,514	5,083	3,892	7,730	4,883	6,030	5,598	4,628
Zonal Export Ability (ZEA) (MW)	6,320	4,601	5,873	6,001	4,984	3,729	5,601	5,030	4,813	2,740

Table ES-4: Initial Planning Resource Auction Deliverables — Spring 2025

The stakeholder review process played an integral role in this study. MISO would like to thank the Loss of Load Expectation Working Group (LOLEWG) and the Resource Adequacy Subcommittee (RASC) for its assistance and input.

1 LOLE Study Process Overview

In compliance with Module E-1 of the MISO Tariff, MISO performed its annual LOLE Study to determine, for each season of Planning Year 2024-2025, the system Unforced Capacity (UCAP) Planning Reserve Margin (PRM) and the per-unit Local Reliability Requirements (LRR) of Local Resource Zone (LRZ) Peak Demand.

In addition to the LOLE analysis, MISO performed seasonal transfer analyses to determine seasonal Zonal Import Ability (ZIA), Zonal Export Ability (ZEA), Capacity Import Limits (CIL) and Capacity Export Limits (CEL). CIL, CEL, and ZIA are used, in conjunction with the LOLE analysis results, in the Planning Resource Auction (PRA). ZEA is informational and not used in the PRA.

The PY 2024-2025 per-unit seasonal LRR UCAP multiplied by the updated LRZ seasonal Peak Demand forecasts submitted for the 2024-2025 PRA determines each LRZ's seasonal LRR. Once the seasonal LRR is determined, the ZIA values and non-pseudo tied exports are subtracted from the seasonal LRR to determine each LRZ's seasonal Local Clearing Requirement (LCR) consistent with Section 68A.6 of Module E-1[1]. An example LCR calculation pursuant to Section 68A.6 of the current effective Module E-1 shows how these values are reached (Table 1-1).

Local Resource Zone (LRZ) EXAMPLE	Example LRZ	Formula Key
Installed Capacity (ICAP)	17,442	[A]
Unforced Capacity (UCAP)	16,326	[B]
Adjustment to UCAP (1d in 10yr)	50	[C]
Local Reliability Requirement (LRR) (UCAP)	16,376	[D]=[B]+[C]
LRZ Peak Demand	14,270	[E]
LRR UCAP per-unit of LRZ Peak Demand	114.8%	[F]=[D]/[E]
Zonal Import Ability (ZIA)	3,469	[G]
Zonal Export Ability (ZEA)	2,317	[H]
Local Clearing Requirement (LCR) EXAMPLE	**Example LRZ**	**Formula Key**
Non-Pseudo Tied Exports (UCAP)	150	[J]
Local Reliability Requirement (LRR) (UCAP)	16,376	[K]=[F]*[E]
Local Clearing Requirement (LCR)	12,757	[L]=[K]-[G]-[J]

Table 1-1: Example Local Clearing Requirement Calculation

The actual effective PRM Requirement (PRMR) for each season of Planning Year 2024-2025 will be determined after the updated LRZ Seasonal Peak Demand forecasts are submitted by November 1, 2023, for the 2024-2025 PRA. The ZIA, ZEA, CIL and CEL values are subject to updates in March 2024 based on changes to exports of MISO resources to non-MISO load, changes to pseudo tied commitments, and updates to facility ratings following the completion of the LOLE Study.

[1] https://www.misoenergy.org/legal/tariff
Effective Date: September 1, 2022

Finally, the Simultaneous Feasibility Test (SFT) is performed as part of the PRA where the deliverability of cleared generation is validated through transfer analysis modeling to ensure transmission reliability. If constraints arise, they are mitigated by adjusting CIL and CEL values as needed.

1.1 Study Improvements

The Planning Year 2024-2025 LOLE Study incorporated additional study improvements, building on those incorporated in the prior studies. Improvements for the PY 2023-2024 LOLE Study included modeling of seasonal outage rates, correlated cold weather outage adder profiles, a probabilistic distribution of non-firm support, and 30 years of hourly wind and solar profiles. Details for these changes can be found in the PY 2023-2024 LOLE Study Report.

The PY 2024-2025 LOLE Study included the following improvements:

- **Enhanced modeling of battery storage resources:** Previously, battery storage was modeled as a must-run resource that is always available at nameplate capacity, unless on a forced outage (assumed to be a rate of 5% for every season). Now, battery storage is modeled as use-limited with a duration of 4 hours.

- **Realistic commercial operation dates for future resources**: PY 2024-2025 study considered more realistic anticipated commercial operation dates (CODs) for future resource additions with executed generation interconnection agreements (GIAs), factoring in macroeconomic and regulatory realities. Interconnection customers have indicated to MISO that factors such as supply-chain issues, regulatory approvals, contractor availability, and other economic factors such as PPAs, are requiring GIA projects to delay commercial operations. Correspondingly, declared anticipated CODs were adjusted based on GIA projects in the queue per customer feedback.

- **Improved consideration of outages driven by extreme cold temperatures**: Accounting of additional forced outages during extreme cold temperatures in the Winter season was updated in the PRM and LRR calculations. For context, the LOLE model has historically utilized a 5-year average EFORd based on historic GADS data. These resource-specific forced outage rates were annualized under the prior annual construct and were seasonalized in the PY 2023-2024 LOLE Study, which better captured the seasonal availability of resources as observed in operations.

  Additional thermal forced outages are added to the model during times of extreme cold temperatures to better capture the magnitude of observed correlated outages. The magnitude of forced outages added increases as temperatures decrease based on the relationship between outages and temperature determined from historic GADS and weather data. The modeling of additional forced outages in the Winter season due to the adder induces a higher volume of forced outages in the model beyond just the average Winter EFORd. Each LRZ has a unique outage/temperature profile based on actual historical forced outages. The incremental cold weather outages are not assigned to a particular resource but instead represent the aggregate impact on the system for coal, gas, and combined cycle resources.

  The accounting of reduced Winter Unforced Capacity resulting from additional extreme cold weather outages was improved in the most recent PRM and LRR calculations. A comparative probabilistic analysis, with and without the cold weather outage adder, was performed to quantify the impact of modeling the cold weather outage adder profiles on the system-wide requirements. This impact was distributed pro-rata to the zonal level based on the average magnitude of the zonal cold weather outage adder profiles used in the LRR calculations.

2 Transfer Analysis

2.1 Calculation Methodology and Process Description

Transfer analyses determined CIL and CEL values for LRZs in each season for Planning Year 2024-2025. Annual adjustments are made for Border External Resources and Coordinating Owner Resources to determine the ZIA and ZEA in each season. Further adjustments are made for exports to non-MISO loads to arrive at the CIL and CEL values. The objective of the transfer analyses is to determine constraints caused by the transfer of capacity between zones and the associated transfer capability. Multiple factors impacted the analysis when compared to previous studies, including:

- Approximately 800 MW of retirements and/or suspensions
- New intermittent resources
- Base model dispatch in MISO and seams

2.1.1 Generation Pools

To determine an LRZ's import or export limit, a transfer is modeled by ramping generation up in a source subsystem and ramping generation down in a sink subsystem. The source and sink definitions depend on the limit being tested. The LRZ studied for import limits is the sink subsystem and the adjacent MISO LBAs are the source subsystem. The LRZ studied for export limits is the source subsystem and the rest of MISO is the sink subsystem. These are the same in all seasons for the upcoming Planning Year.

Transfers can cause potential issues, which are addressed through the study assumptions. First, an abundantly large source pool spreads the impact of the transfer widely which can cause differences in studied zones' transfer capabilities and the identified constraints. Second, ramping up generation from remote areas could cause electrically distant constraints for any given LRZ, which should not determine a zone's limit. For example, export constraints due to dispatch of LRZ 1 generation in the northwest portion of the footprint should not limit the import capability of LRZ 10, which covers the MISO portion of Mississippi.

To address these potential issues, the transfer studies limit the source pool for the import studies to the Tier 1 and Tier 2 adjacent LBAs to the study zone. Since the generation that is ramped up in export studies are contained in the study LRZ, these issues only apply to import studies. Generation within the zone studied for an export limit is ramped up and constraints are expected to be near or in the study zone.

2.1.2 Redispatch

Limited redispatch is applied after performing transfer analyses to mitigate constraints. Redispatch ensures constraints are not caused by the base dispatch and aligns with potential actions that can be implemented for the constraint by MISO control room operators. Redispatch scenarios can be designed to address multiple constraints, as required, and may be used for constraints that are electrically close to each other or to further optimize transfer limits for several constraints requiring only minor redispatch. The redispatch assumptions include:

- The use of no more than 10 conventional fuel plants or intermittent resources
- Redispatch limit at 2,000 MW total (1,000 MW up and 1,000 MW down)
- No adjustments to nuclear units
- No adjustments to the portions of pseudo-tied units committed to non-MISO load

2.1.3 Sensitivity

New to the transfer analyses this year is the ability for Transmission Owners in a specific zone to request a sensitivity be included in the generation-to-generation transfer to allow for the True Transfer Limit to be identified. The sensitivity would allow excluded units to be included in the generation-to-generation transfer for a zone's CIL. Excluded units mainly include nuclear units and units not to be used in zonal transfers from the latest MTEP model. This sensitivity can only be requested for a CIL study. A sensitivity would only be accepted for a particular zone if they are in the situation portrayed below by the chart in Figure 2-1.

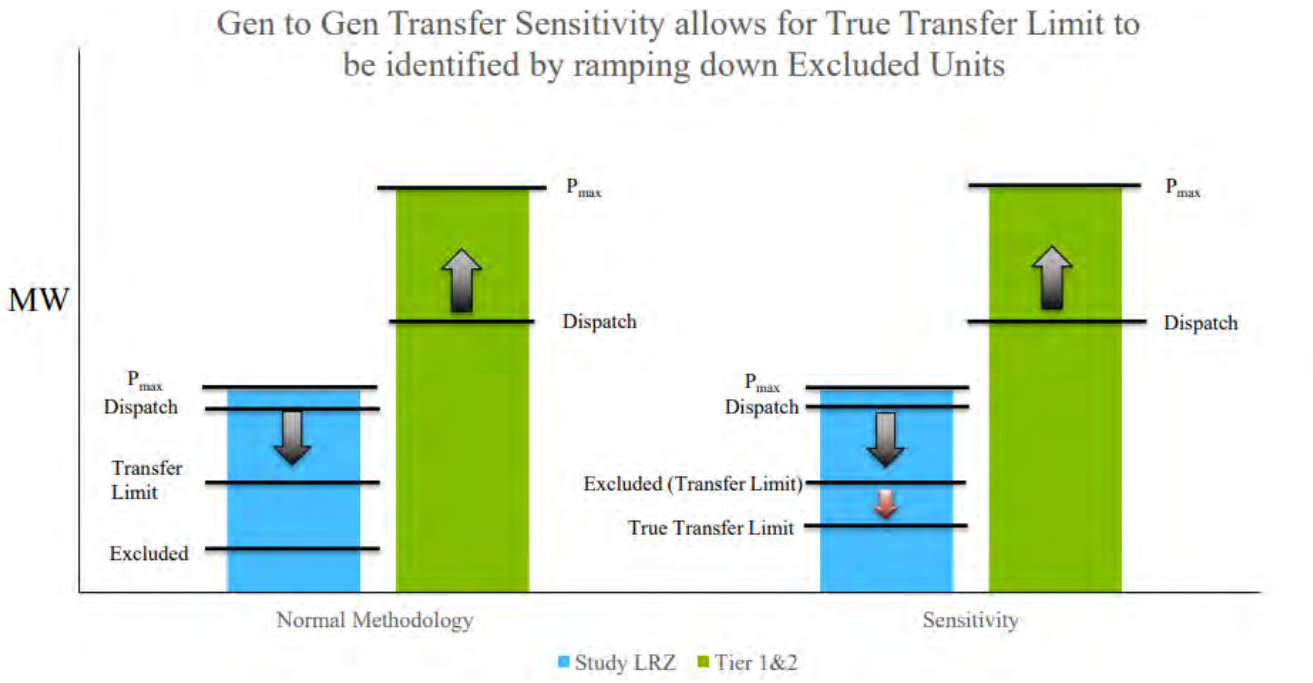


Figure 2-1: Generation-to-Generation Transfer Sensitivity

The two bars shown for the Normal Methodology would not allow for a sensitivity to be requested by a Transmission Owner. In this situation, since the transfer limit is already identified before hitting the excluded units, a request for a generation-to-generation transfer sensitivity would not be accepted. The two bars shown for the Sensitivity identify a situation where a request for a generation-to-generation transfer sensitivity would be accepted. When ramping down generation, the excluded units are hit before the True Transfer Limit, but since the rest of the units are excluded, the transfer limit would be identified as the point where the generation-to-generation stops at the excluded units. With a sensitivity in place, the generation-to-generation transfer would continue into the excluded units and the True Transfer Limit would be identified.

LRZ 10 was the only Local Resource Zone to utilize a generation-to-generation transfer sensitivity and have the results of which included in their Capacity Import Limit for Planning Year 2024-2025.

2.1.4 Generation Limited Transfer for CIL/CEL and ZIA/ZEA

When conducting transfer analysis to determine import or export limits, the source subsystem might run out of generation to dispatch before identifying a valid constraint caused by a transmission limit. MISO developed a Generation Limited Transfer (GLT) process to identify transmission constraints in these situations, when possible, for both imports and exports.

After running the First Contingency Incremental Transfer Capability (FCITC) analysis to determine limits for each LRZ, MISO will determine whether a zone is experiencing a GLT (e.g. whether the first constraint would occur only after all the generation is dispatched at its maximum amount). If the LRZ experiences a GLT, MISO will adjust the base model depending on whether it is an import or export analysis and re-run the transfer analysis.

For an export study, when a transmission constraint has not been identified after all generation has been dispatched within the exporting system (LRZ under study), MISO will decrease load and generation dispatch in the study zone. The adjustment creates additional capacity to export from the zone. After the adjustments are complete, MISO will re-run the transfer analysis. If a GLT reappears, MISO will make further adjustments to the load and generation of the study zone.

For an import study, when a transmission constraint has not been identified after all generation has been dispatched within the source subsystem, MISO will decrease load and generation in the source subsystem. This increases the export capacity of the adjacent LBAs for the study zone. After the adjustments are complete, MISO will run the transfer analysis again. If a GLT reappears, MISO will make further adjustments to the model's load and generation in the source subsystem.

FCITC could indicate the transmission system can support larger thermal transfers than would be available based on installed generation for some zones—however, large variations in load and generation for any zone may lead to unreliable limits and constraints. Therefore, MISO limits load scaling for both import and export studies to 50 percent of the zone's load. In a GLT, redispatch, or GLT plus redispatch scenario, the FCITC of the most limiting constraint might exceed Zonal Export/Import Capability. If the GLT does not produce a limit for a zone, either due to a valid constraint not being identified or due to other considerations as listed in the prior paragraph, MISO shall report that LRZ as having no limit and ensure that the limit will not bind in the first iteration of the Simultaneous Feasibility Test (SFT).

2.1.5 Voltage Limited Transfer for CIL/CEL and ZIA/ZEA

Zonal imports may be limited by voltage constraints due to a decrease in the generation in the study zone. Voltage constraints might occur at lower transfer levels than thermal limits determined by linear FCITC. As such, LOLE studies may evaluate power-voltage curves for LRZs with known voltage-based transfer limitations identified through existing MISO or Transmission Owner studies. Such evaluation may also occur if an LRZ's import reaches a level where the majority of the zone's load would be served using imports from resources outside of the zone. MISO will coordinate with stakeholders as it encounters these scenarios. For Planning Year 2024-2025, only Local Resource Zones 1, 4, and 7 import analyses included voltage screening and study. No studies identified a voltage limit with lower transfer capability than the thermal limit for Planning Year 2024-2025.

2.2 Powerflow Models and Assumptions

2.2.1 Tools Used

MISO used the Siemens PTI Power System Simulator for Engineering (PSS/E) and PowerGEM Transmission Adequacy and Reliability Assessment (TARA) tools.

2.2.2 Inputs Required

Thermal transfer analysis requires powerflow models and related input files. MISO used contingency files from MTEP[2] reliability assessment studies. Single-element contingencies in MISO and seam areas were also evaluated.

MISO developed a subsystem file to monitor its footprint and seam areas which was used for all seasons. LRZ definitions were developed as sources and sinks in the study. See Appendix C for tables containing adjacent area definitions (Tiers 1 and 2) used for this study. The monitored file includes all facilities under MISO functional control and single elements in the seam areas of 100 kV and above.

2.2.3 Powerflow Modeling

The MTEP23 models were built using MISO's Model on Demand (MOD) model data repository, with the following base assumptions (Table 2-1).

Scenario	Effective Date	Projects Applied	External Modeling	Load and Generation Profile	Wind %	Solar %
Summer 2024	July 15th	MTEP Appendix A and Target A	ERAG MMWG 2022 Series 2024 Summer Peak Load Model	Summer Peak	18%	50%
Fall 2024	October 15th	MTEP Appendix A and Target A	ERAG MMWG 2022 Series 2024 Spring Light Load Model	Fall Peak	28.5%	0%
Winter 2024-2025	January 15th	MTEP Appendix A and Target A	ERAG MMWG 2022 Series 2024 Winter Peak Load Model	Winter Peak	67%	0%
Spring 2025	April 15th	MTEP Appendix A and Target A	ERAG MMWG 2022 Series 2024 Spring Light Load Model	Spring Peak	28.5%	0%

Table 2-1: Model Assumptions

MISO excluded several types of units from the transfer analysis dispatch—these units' base dispatch remained fixed.

- Nuclear dispatch does not change for any transfer without a sensitivity
- Wind and solar resources can be ramped down, but not up
- Pseudo-tied resources were modeled at their expected commitments to non-MISO load, although portions of these units committed to MISO could participate in transfer analyses

System conditions such as load, dispatch, topology, and interchange have an impact on transfer capability. The model was reviewed as part of the base model built for MTEP23 analyses, with study files made available on MISO ShareFile.

[2] Refer to the Transmission Planning BPM (BPM-20) for more information regarding MTEP input files. https://www.misoenergy.org/legal/business-practice-manuals/

MISO worked closely with Transmission Owners and stakeholders to model the transmission system accurately, as well as to validate constraints and redispatch. Like other planning studies, transmission outage schedules were not included in the analyses. This is driven partly by limited availability of outage information as well as current transmission planning standards. Although no outage schedules were evaluated, single element contingencies were evaluated. This includes Bulk Electric System lines, transformers, and generators.

Contingency coverage covers most of category P1 and some of category P2 outlined in Table 1 of NERC Reliability Standard TPL-001.

2.2.4 General Assumptions

MISO uses TARA to process the powerflow model and associated input files to determine the seasonal import and export limits of each LRZ by determining the transfer capability. Transfer capability measures the ability of interconnected power systems to reliably transfer power from one area to another under specified system conditions. The incremental amount of power that can be transferred is determined through FCITC analysis. FCITC analysis and base power transfers provide the information required to calculate the First Contingency Total Transfer Capability (FCTTC), which indicates the total amount of transferrable power before a constraint is identified. FCTTC is the base power transfer plus the incremental transfer capability (Equation 2-1). All published limits are based on the zone's FCTTC and may be adjusted for capacity exports.

$$First\ Contingency\ Total\ Transfer\ Capability\ (FCTTC) = Base\ Power\ Transfer + FCITC$$

Equation 2-1: Total Transfer Capability

FCITC constraints are identified under base case situations in each season or under P1 contingencies provided through the MTEP process. Linear FCITC analysis identifies the limiting constraints using a minimum transfer Distribution Factor (DF) cutoff of 3 percent, meaning the transfer must increase the loading on the overloaded element, under system intact or contingency conditions, by 3 percent or more.

A pro-rata dispatch is used, which ensures all available generators will reach their maximum dispatch level at the same time. The pro-rata dispatch is based on the MW reserve available for each unit and the cumulative MW reserve available in the subsystem. The MW reserve is found by subtracting a unit's base model generation dispatch from its maximum dispatch, which reflects the available capacity of the unit.

Table 2-2 and Equation 2-2 show an example of how one unit's dispatch is set, given all machine data for the source subsystem.

Machine	Base Model Unit Dispatch (MW)	Minimum Unit Dispatch (MW)	Maximum Unit Dispatch (MW)	Reserve MW (Unit Dispatch Max – Unit Dispatch Min)
1	20	20	100	80
2	50	10	150	100
3	20	20	100	80
4	450	0	500	50
5	500	100	500	0
			Total Reserve	**310**

Table 2-2: Example Subsystem

$$\textbf{\textit{Machine 1 Incremental Post Transfer Dispatch}} = \frac{\textbf{\textit{Machine 1 Reserve MW}}}{\textbf{\textit{Source Subsystem Reserve MW}}} \times \textbf{\textit{Transfer Level MW}}$$

$$Machine\ 1\ Incremental\ Post\ Transfer\ Dispatch = \frac{80}{310} \times 100 = 25.8$$

$$Machine\ 1\ Incremental\ Post\ Transfer\ Dispatch = 25.8$$

Equation 2-2: Machine 1 Dispatch Calculation for 100 MW Transfer

2.3 Results for CIL/CEL and ZIA/ZEA

Study constraints and associated ZIA, ZEA, CIL, and CEL for each LRZ for each season were presented and reviewed through the LOLEWG with final results for Planning Year 2024-2025 presented at the October 17th, 2023 meeting. Table 2-3 below shows the Planning Year 2024-2025 CIL and ZIA with corresponding constraint, GLT, and redispatch (RDS) information.

All zones had an identified ZIA this year. If there is no valid constraint identified, the following equation will be used where the FCITC will be replaced by the Tier 1 and Tier 2 capacity.

$$\textbf{\textit{ZIA}} = \textbf{\textit{FCITC}} + \textbf{\textit{Area Interchange}} - \textbf{\textit{Border External Resources and Coordinating Owners}}$$

Equation 2-3: Zonal Import Ability (ZIA) Calculation

LRZ1	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2024	Wien - T Corners 115 kV	Arpin - Eau Claire 345 kV	10%	826MWx2	6460	6462
Fall 2024	Mitchell County - Adams 345 kV	Sherburne Country Generator	None	977MWx2	6500	6502
Winter 2024/25	Pleasant Valley - Byron 161 kV	Byron - Pleasant Valley 345 kV	None	670MWx2	4691	4693
Spring 2025	Coal Creek CR4 - Coal Creek TP4 230 kV	Coal Creek - Stanton 230 kV	None	1000MWx2	4941	4943
LRZ2	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2024	Paddock 345/138 kV Transformer	Riverside Generator	None	586MWx2	4506	4506
Fall 2024	Arpin - Sigel 138 kV	Pow STG20 Generator	None	1000MWx2	5719	5719
Winter 2024/25	Rockdale - Lakehead Cambridge Tap 138 kV	Cambridge Tap - Rockdale 138 kV	None	614MWx2	5523	5523
Spring 2025	Arpin - Sigel 138 kV	Arpin - Rocky Run 345kV	None	1000MWx2	5034	5034
LRZ3	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2024	Ottumwa 345/161 kV Transformer	Ottumwa Generator	None	617MWx2	4911	5009
Fall 2024	Ottumwa 345/161 kV Transformer	Ottumwa Generator	None	365MWx2	6684	6789
Winter 2024/25	Sub 3458 (Nebraska City) - Sub 3456 345 kV	Sub 3455 - Sub 3740 345 kV	None	440MWx2	5600	5704
Spring 2025	Ottumwa 345/161 kV Transformer	Ottumwa Generator	None	527MWx2	6514	6626
LRZ4	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2024	None	None	20%	None	9857	10790
Fall 2024	Palmyra - Marblehead North 161 kV	Herleman - Palmyra Tap 345 kV	10%	533MWx2	5699	6637
Winter 2024/25	Palmyra 345/161 kV Transformer	Herleman - Palmyra Tap 345 kV	None	1000MWx2	5811	6731
Spring 2025	Palmyra - Marblehead North 161 kV	Herleman - Palmyra Tap 345 kV	None	1000MWx2	5083	6003
LRZ5	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2024	Moro - Miles 138 kV	Roxford - Moro 345 kV	None	1000MWx2	3208	3208
Fall 2024	Moro - Miles 138 kV	Roxford - Moro 345 kV	None	202MWx2	3786	3786
Winter 2024/25	Moro - Miles 138 kV	Roxford - Moro 345 kV	None	1000MWx2	4477	4477
Spring 2025	Moro - Miles 138 kV	Roxford - Moro 345 kV	None	356MWx2	3892	3892
LRZ6	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2024	Cayuga Sub- Cayuga 345 kV	Kansas West - Sugar Creek 345 kV	5%	712MWx2	7197	7463
Fall 2024	Cayuga Sub - Cayuga 345 kV	Kansas West - Sugar Creek 345 kV	None	282MWx2	8661	8954
Winter 2024/25	Sullivan - Petersburg 345 kV	Rockport - Jefferson 765 kV	None	890MWx2	8286	8526
Spring 2025	Lawrenceville South - Vincennes 138 kV	Albion South - Gibson 345 kV	None	294MWx2	7730	8015
LRZ7	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2024	Monroe 1&2 - Brownstown (Superior) 345kV	Monroe 1&2 - Wayne 345 kV	None	1000MWx2	4490	4500
Fall 2024	Verona - J758 138 kV	J758 - Verona West 138 kV	None	373MWx2	4390	4400
Winter 2024/25	Argenta - Tompkins 345 kV	Argenta - Battle Creek 345 kV	None	1000MWx2	4656	4666
Spring 2025	Stillwell - Dumont 345 kV	Wilton Center - Dumont 765 kV	None	927MWx2	4883	4893
LRZ8	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2024	Winnfield 230/115 kV Transformer	Montgomery - Clarence 230 kV	None	1000MWx2	3444	3536
Fall 2024	Mount Olive - Vienna 115 kV	Mount Olive - Eldorado 500 kV	None	1000MWx2	4942	5040
Winter 2024/25	Little Gypsy - Fairview 230 kV	Michoud - Front Street 230 kV	None	1000MWx2	4262	4336
Spring 2025	Winnfield 230/115 kV Transformer	Mount Olive - Layfield 500 kV	10%	1000MWx2	6030	6124
LRZ9	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2024	Danville - Dodson 115 kV	Mount Olive - Layfield 500 kV	None	1000MWx2	4794	5613
Fall 2024	Daniel - Daniel Intermediate 1 230 kV	Daniel - Daniel Intermediate 2 230 kV	None	1000MWx2	5608	6435
Winter 2024/25	Bogalusa 500/230 kV Transformer	Mcknight - Franklin 500 kV	None	1000MWx2	4623	5420
Spring 2025	Bogalusa 500/230 kV Transformer	Mcknight - Franklin 500 kV	None	1000MWx2	5598	6417
LRZ10	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2024	Perryville - Baxter Wilson 500 kV	Grand Gulf Generator	None	1000MWx2	3564	3564
Fall 2024	Mcknight - Franklin 500 kV	Baxter Willson - Perryville 500 kV	21%	929MWx2	4736	4736
Winter 2024/25	Perryville - Baxter Wilson 500 kV	Grand Gulf Generator	None	1000MWx2	3219	3219
Spring 2025	Mcknight - Franklin 500 kV	Baxter Willson - Perryville 500 kV	34%	284MWx2	4628	4628

Table 2-3: Planning Year 2024–2025 Import Limits

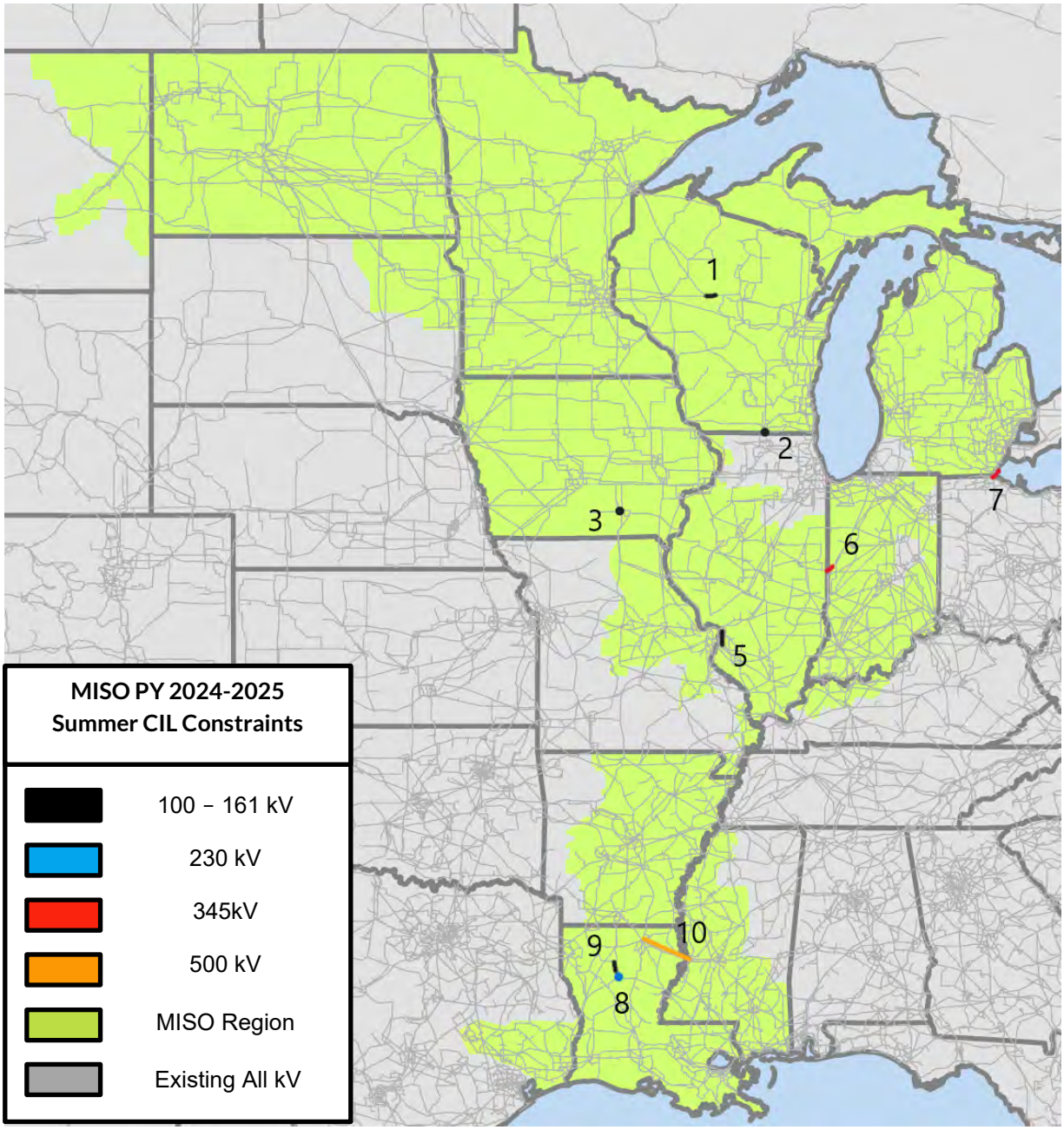


Figure 2-2: Planning Year 2024-2025 Summer Capacity Import Constraints Map

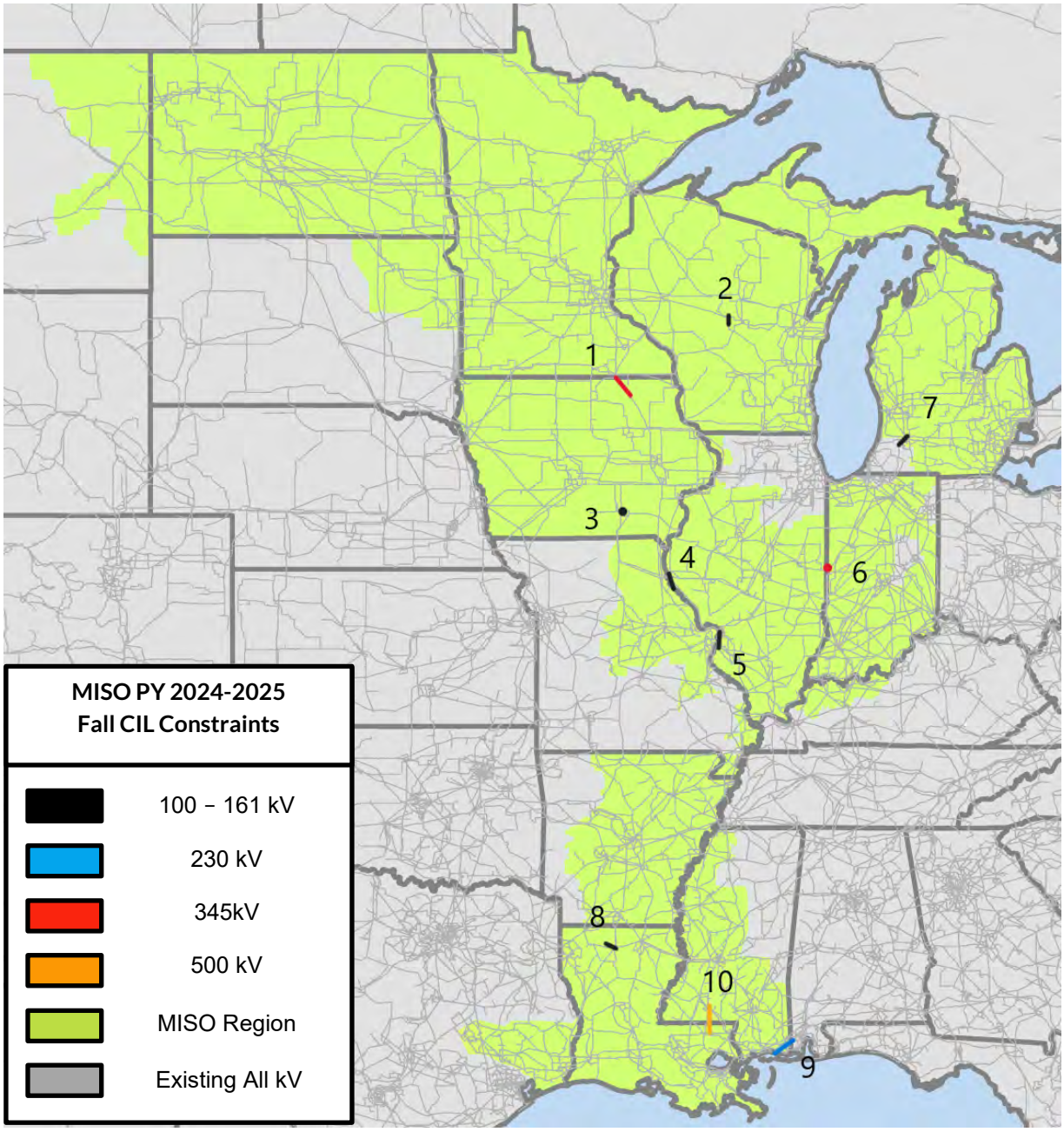


Figure 2-3: Planning Year 2024-2025 Fall Capacity Import Constraints Map

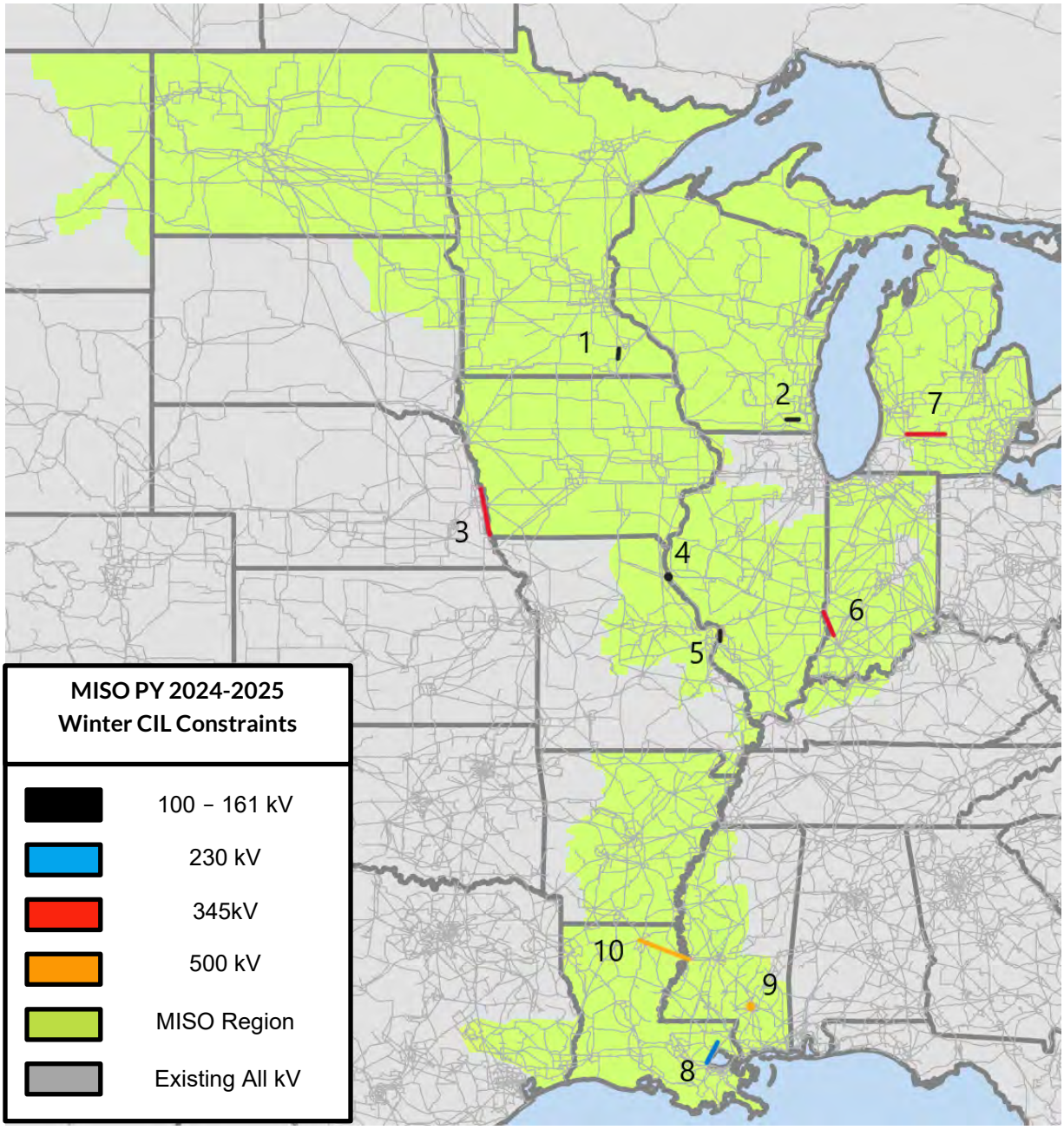


Figure 2-4: Planning Year 2024-2025 Winter Capacity Import Constraints Map

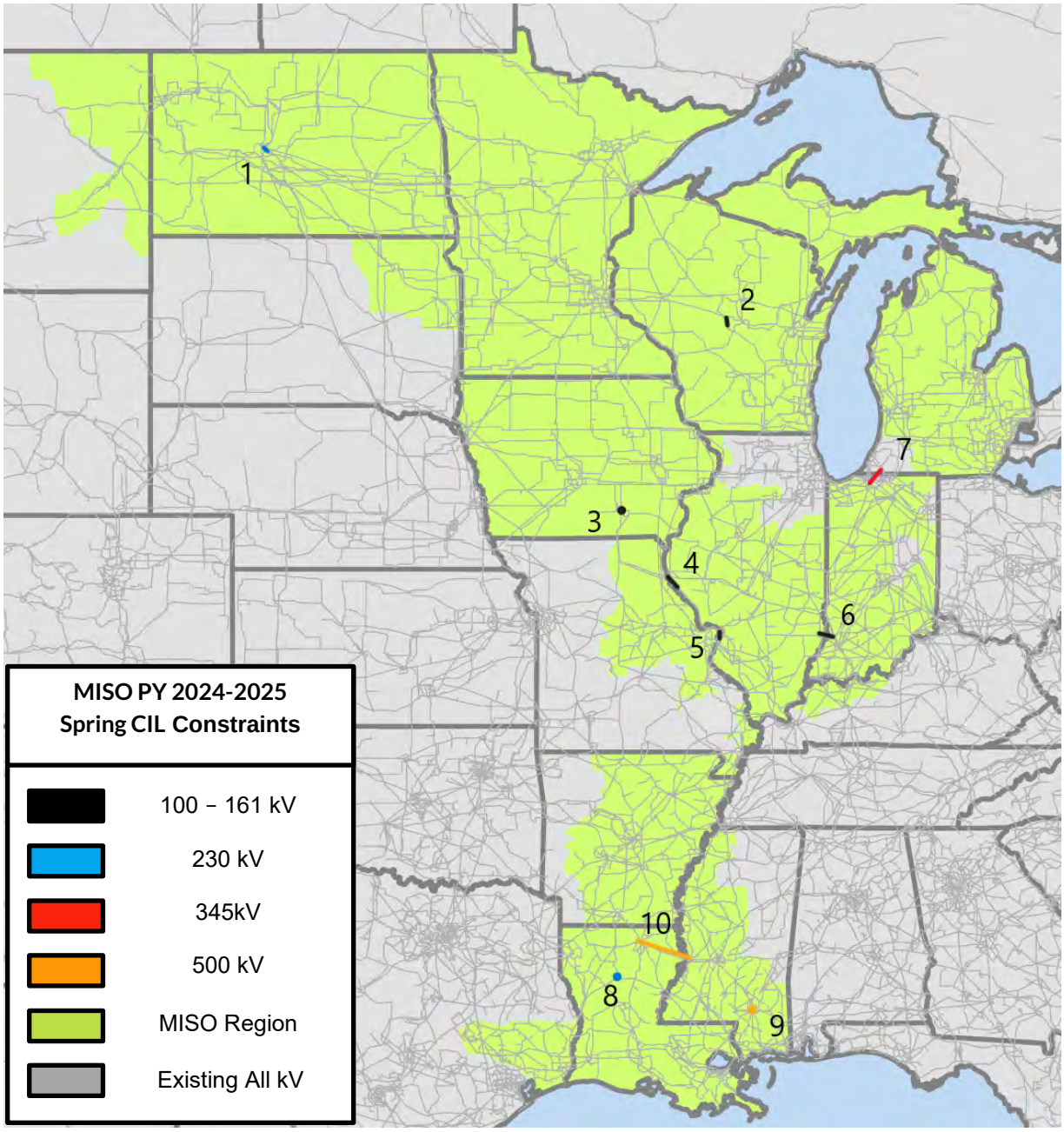


Figure 2-5: Planning Year 2024-2025 Spring Capacity Import Constraints Map

Capacity Exports Limits are found by increasing generation in the study zone and decreasing generation in the rest of the MISO footprint to create a transfer. Table 2-4 below shows the Planning Year 2024-2025 CEL and ZEA with corresponding constraint, GLT, and redispatch information.

LRZ1	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2024	Split Rock - Sioux Falls 230 kV	Split Rock - Sioux City 345 kV	10%	1000MWx2	4539	4537
Fall 2024	Arpin - Sigel 138 kV	Arpin - Rocky Run 345kV	None	302MWx2	5713	5711
Winter 2024/25	Split Rock - Sioux Falls 230 kV	Split Rock - Sioux City 345 kV	None	847MWx2	5176	5174
Spring 2025	Split Rock - Sioux Falls 230 kV	Split Rock - Sioux City 345 kV	None	194MWx2	6320	6318
LRZ2	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2024	Pleasant Prairie - Zion 345 kV	Pleasant Prairie - Zion EC 345 kV	40%	295MWx2	3971	3971
Fall 2024	Pleasant Prairie - Zion 345 kV	Pleasant Prairie - Zion EC 345 kV	None	936MWx2	4512	4512
Winter 2024/25	Pleasant Prairie - Zion EC 345 kV	Pleasant Prairie - Zion 345 kV	30%	1000MWx2	4772	4772
Spring 2025	Pleasant Prairie - Zion EC 345 kV	Pleasant Prairie - Zion 345 kV	None	1000MWx2	4601	4601
LRZ3	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2024	None	None	50%	None	5548	5450
Fall 2024	Sandburg 161/138 kV Transformer	Galesburg - Oak Grove 345 kV	40%	515MWx2	7018	6913
Winter 2024/25	Wapello County - Appanoose County 161 kV	Zachary - Hughes 345kV	None	1000MWx2	9079	8975
Spring 2025	Sandburg 161/138 kV Transformer	Galesburg - Oak Grove 345 kV	50%	285MWx2	5873	5761
LRZ4	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2024	None	None	50%	None	3663	2730
Fall 2024	None	None	50%	None	4801	3863
Winter 2024/25	None	None	50%	None	5570	4650
Spring 2025	None	None	50%	None	6001	5081
LRZ5	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2024	None	None	40%	None	4644	4644
Fall 2024	Mass 345/161 kV Transformer	Mass - Joppa 345 kV	None	360MWx2	5402	5402
Winter 2024/25	None	None	50%	None	6229	6229
Spring 2025	Mass 345/161 kV Transformer	Shawnee - Mass 345 kV	None	1000MWx2	4984	4984
LRZ6	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2024	BR Tap - Paradise 161 kV	Paradise - Paradise CC Units 3-4 161 kV	35%	93MWx2	5903	5637
Fall 2024	South - Southeast 138 kV	Hanna - Franklin Township 138 kV	None	624MWx2	3812	3519
Winter 2024/25	Grandview - Newtonville 138 kV	Daviess - Coleman EHV Substation 345 kV	None	388MWx2	1647	1407
Spring 2025	South - Southeast 138 kV	Hanna - Franklin Township 138 kV	None	575MWx2	3729	3444
LRZ7	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2024	Lallendorf - Fostoria Central 345 kV	Lemoyne - Fostoria Central 345 kV	30%	921MWx2	5719	5709
Fall 2024	Monroe 1&2 - Lallendorf 345 kV	Morocco - Allen Jct 345 kV	None	1000MWx2	5391	5381
Winter 2024/25	Morocco - Allen Jct 345 kV	Lallendorf - Monroe 345 kV	None	1000MWx2	5753	5743
Spring 2025	Monroe 1&2 - Lallendorf 345 kV	Morocco - Allen Jct 345 kV	None	564MWx2	5601	5591
LRZ8	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2024	Perryville - Baxter Wilson 500 kV	Grand Gulf Generator	30%	1000MWx2	6263	6171
Fall 2024	Independence - Moorefield 161 kV	Independence - Power Line Road EHV 500 kV	None	35MWx2	4310	4212
Winter 2024/25	Arklahoma - Hot Springs East 115 kV	Hot Springs West - Arklahoma 115 kV	50%	155MWx2	5882	5808
Spring 2025	Cash - Jonesboro 161 kV	Independence - Power Line Road EHV 500 kV	None	177MWx2	5030	4936
LRZ9	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2024	PPG - Verdine 230 kV	PPG - Manena 230 kV	None	1000MWx2	3178	2359
Fall 2024	White Bluff - Keo 500 kV	Sheridan - Mabelvale 500 kV	None	1000MWx2	4429	3602
Winter 2024/25	Adams Creek - Angie 230 kV	French Branch - Slidell 230 kV	None	1000MWx2	2900	2103
Spring 2025	Michoud - Front Street 230 kV	Mcknight - Franklin 500 kV	None	1000MWx2	4813	3994
LRZ10	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2024	Clarksdale - Lyon 115 kV	MEPS Clarkesdale - Moon Lake 230kV	None	377MWx2	1840	1840
Fall 2024	Clarksdale - Lyon 115 kV	MEPS Clarkesdale - Moon Lake 230kV	None	535MWx2	2889	2889
Winter 2024/25	Clarksdale - Lyon 115 kV	MEPS Clarkesdale - Moon Lake 230kV	None	284MWx2	2993	2993
Spring 2025	Clarksdale - Lyon 115 kV	MEPS Clarkesdale - Moon Lake 230kV	None	535MWx2	2740	2740

Table 2-4: Planning Year 2024–2025 Export Limits

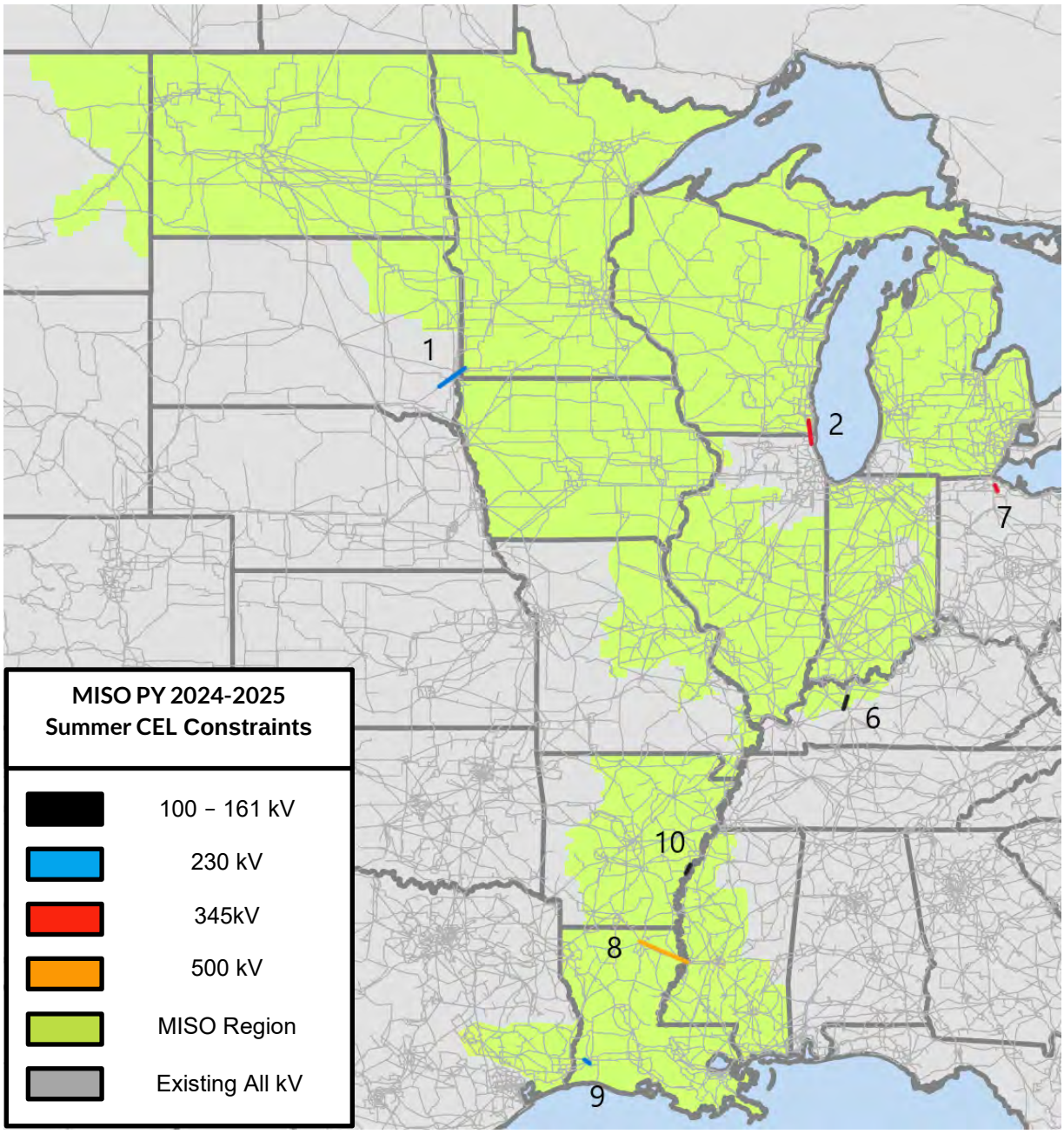


Figure 2-6: Planning Year 2024-2025 Summer Export Constraint Map

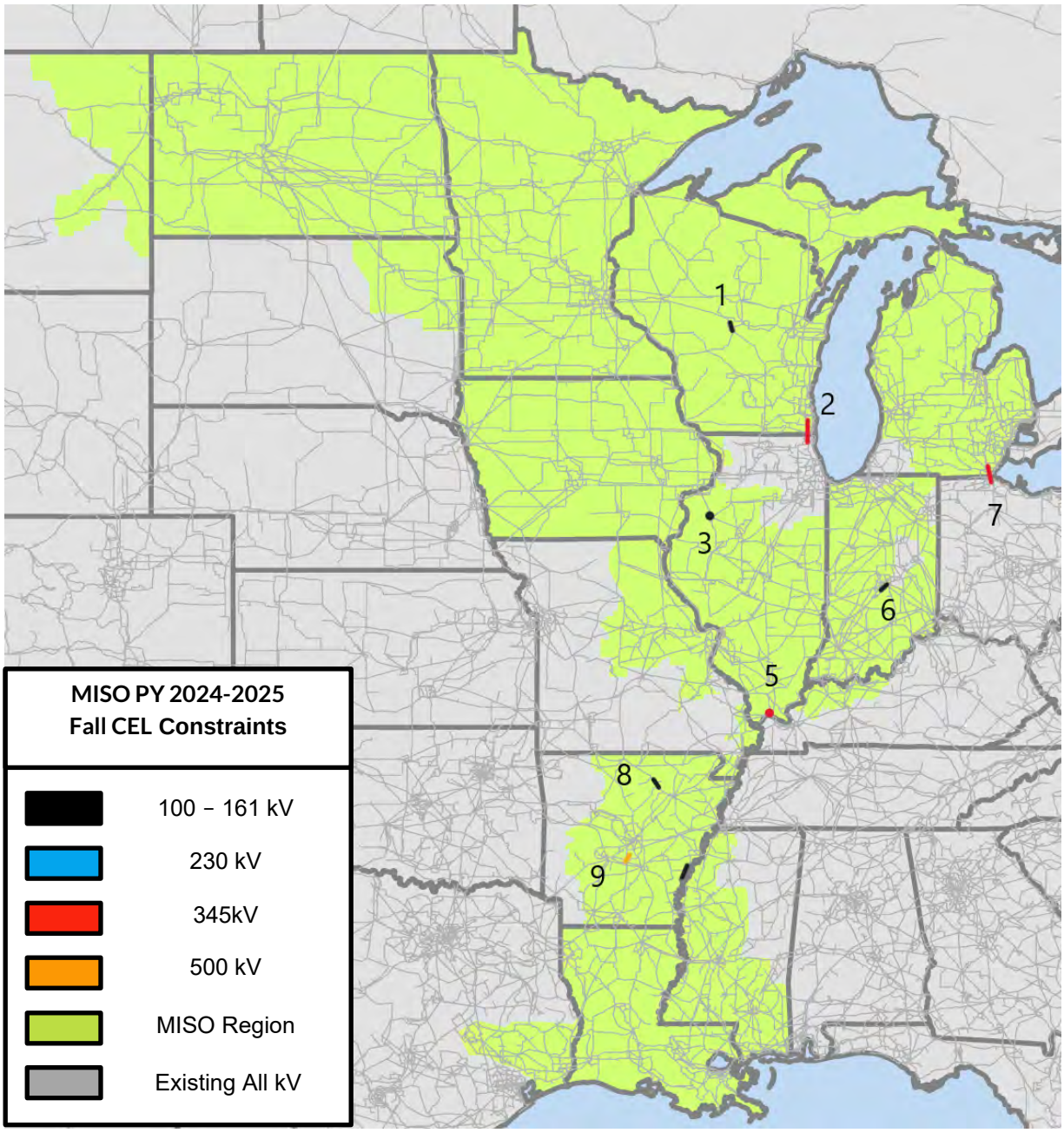


Figure 2-7: Planning Year 2024-2025 Fall Export Constraint Map

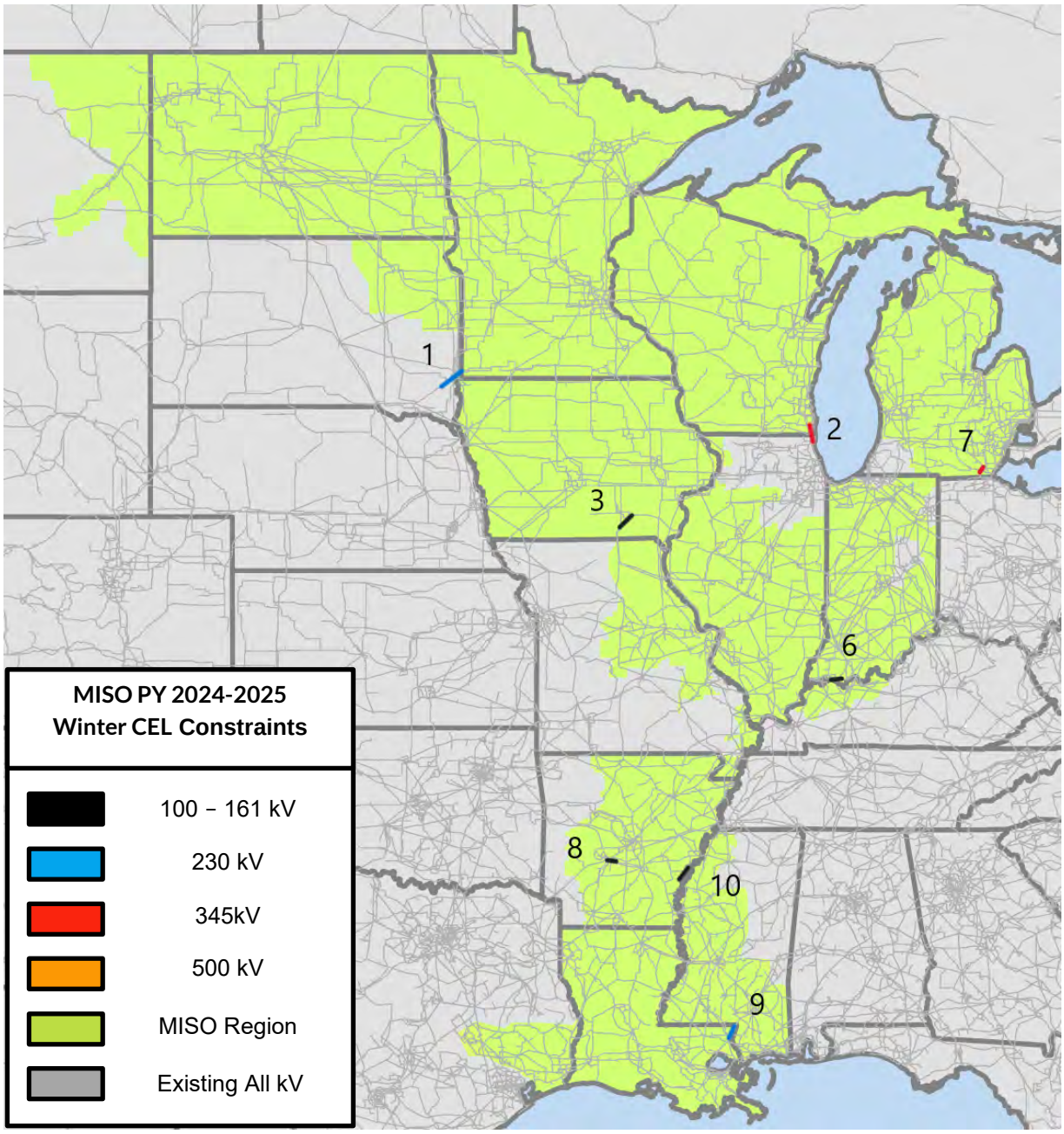


Figure 2-8: Planning Year 2024-2025 Winter Export Constraint Map

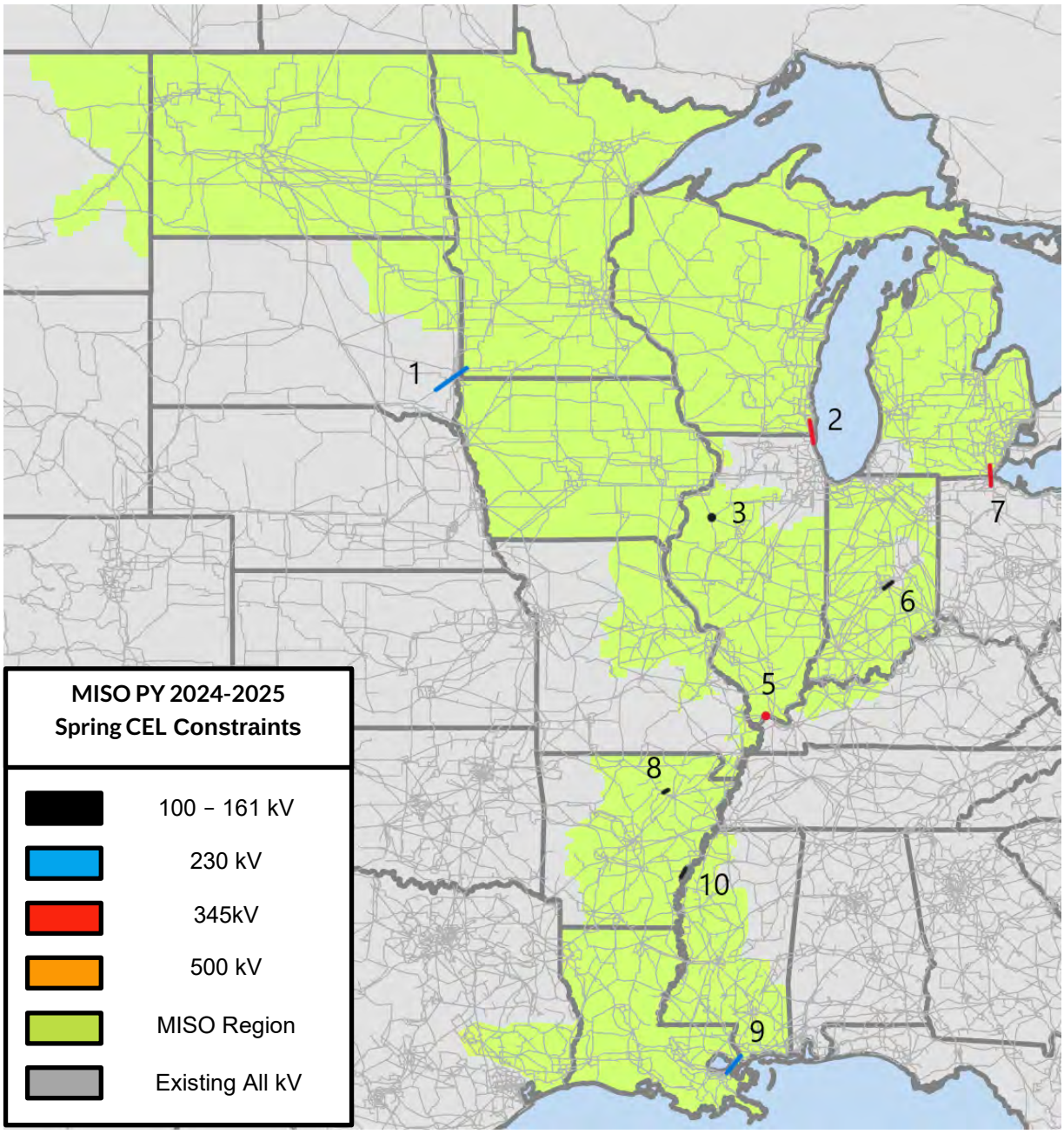


Figure 2-9: Planning Year 2024-2025 Spring Export Constraint Map

3 Loss of Load Expectation Analysis

3.1 LOLE Modeling Input Data and Assumptions

MISO uses a program developed and maintained by Astrapé Consulting called Strategic Energy & Risk Valuation Model (SERVM) to calculate LOLE for the applicable Planning Year. SERVM uses a sequential Monte Carlo simulation to model a generation system and to assess the system's reliability, based on any number of interconnected areas. SERVM calculates LOLE for the MISO system and for each LRZ by stepping through the year chronologically and taking into account generation, load, load modifying and energy efficiency resources, equipment forced outages, planned and maintenance outages, weather and economic uncertainty, and external support.

Building the SERVM model is the most time-consuming task of the LOLE Study. Several sensitivities are built in order to determine how specific inputs and variables impact the results. The base case models determine the seasonal MISO PRM Installed Capacity (ICAP), PRM Unforced Capacity (UCAP), and the Local Reliability Requirements (LRRs) for each LRZ for future Planning Years one, four, and six.

3.2 MISO Generation

3.2.1 Thermal Units

The Planning Year 2024-2025 LOLE Study used the 2023-2024 PRA converted capacity as a starting point for which resources to include in the study. This ensured that only resources eligible as Planning Resources were included in the LOLE Study. An exception was made to include resources with a signed and executed GIA that have an anticipated in-service date (adjusted for average GI delays) for PY 2024-2025. All internal Planning Resources were modeled in the LRZ in which they are physically located. Additionally, Coordinating Owner External Resources and Border External Resources were modeled as being internal to the LRZ in which they are committed to serving load.

Seasonal forced outage rates and annualized planned maintenance outage rates were calculated over a five-year period (January 2016 to December 2022) for each resource. Some resources did not have five years of historical data in MISO's Generator Availability Data System (PowerGADS)—however, if they had at least 3 consecutive months of outage data, resource-specific information was used to calculate their seasonal forced and planned maintenance outage rates. Resources with fewer than 3 consecutive months of resource-specific outage data were assigned the corresponding MISO seasonal class average forced outage rate and annualized planned maintenance outage rate based on their resource type. The overall MISO ICAP-weighted seasonal class average forced outage rates and annualized planned maintenance outage rate were applied in lieu of class averages for classes with fewer than 30 resources reporting 12 or more months of data.

Each nuclear unit has a fixed maintenance schedule, which was pulled from publicly available information and was modeled for each of the study years.

The historical class average outage rates as well as the MISO system-wide weighted average forced outage rate are provided in Table 3-1 to show the year-over-year trends, as well as in Table 3-2 on a seasonal basis.

Pooled EFORd GADS Years	2018-2022 (%)	2017-2021 (%)	2016-2020 (%)	2015-2019 (%)	2014-2018 (%)	2013-2017 (%)
LOLE Study Planning Year	**PY 2024-2025** Summer	**PY 2023-2024** Summer	**PY 2022-2023** Annualized	**PY 2021-2022** Annualized	**PY 2020-2021** Annualized	**PY 2019-2020** Annualized
Combined Cycle	5.92	5.54	5.85	5.52	5.70	5.37
Combustion Turbine (0-20 MW)	24.42	23.40	35.20	36.38	40.39	23.18
Combustion Turbine (20-50 MW)	6.54	6.30	13.65	14.20	15.29	15.76
Combustion Turbine (50+ MW)	4.88	4.07	4.36	4.76	4.65	5.18
Diesel Engines	17.14	12.79	7.25	10.05	23.53	10.26
Fluidized Bed Combustion	*	*	*	*	*	*
Hydro (0-30 MW)	*	*	*	*	*	*
Hydro (30+ MW)	*	*	*	*	*	*
Nuclear	*	*	*	*	*	*
Pumped Storage	*	*	*	*	*	*
Steam – Coal (0-200 MW)	7.91	6.34	8.72	7.12	6.34	5.83
Steam - Coal (200-600 MW)	7.81	7.57	10.27	10.20	9.85	9.60
Steam - Coal (600-1,000 MW)	9.57	8.47	8.83	8.38	8.41	8.05
Steam - Gas	14.04	12.48	11.84	12.91	12.54	11.56
Steam - Oil	*	*	*	*	*	*
Steam - Waste Heat	*	*	*	*	*	*
Steam - Wood	*	*	*	*	*	*
MISO Weighted System-wide	8.24	8.23	9.04	9.36	9.24	9.28

Table 3-1: Historical Class Average Forced Outage Rates

Pooled EFORd GADS Years	2018-2022 (%)	2018-2022 (%)	2018-2022 (%)	2018-2022 (%)
LOLE Study Planning Year 2024-2025	**Summer 2024**	**Fall 2024**	**Winter 2024-2025**	**Spring 2025**
Combined Cycle	5.92	7.43	5.38	6.55
Combustion Turbine (0-20 MW)	24.42	24.17	46.17	51.36
Combustion Turbine (20-50 MW)	6.54	18.59	50.59	34.26
Combustion Turbine (50+ MW)	4.88	7.23	10.53	5.15
Diesel Engines	17.14	14.26	24.94	8.89
Fluidized Bed Combustion	*	*	*	*
Hydro (0-30 MW)	*	*	*	*
Hydro (30+ MW)	*	*	*	*
Nuclear	*	*	*	*
Pumped Storage	*	*	*	*
Steam – Coal (0-200 MW)	7.91	9.69	8.71	11.85
Steam - Coal (200-600 MW)	7.81	10.91	9.07	8.28
Steam - Coal (600-1,000 MW)	9.57	7.78	10.32	11.41
Steam - Gas	14.04	13.26	11.11	12.07
Steam - Oil	*	*	*	*
Steam - Waste Heat	*	*	*	*
Steam - Wood	*	*	*	*
MISO Weighted System-wide	8.24	9.15	11.23	10.33

Table 3-2: Planning Year 2024-2025 Seasonal Class Average Forced Outage Rates

3.2.2 Behind-the-Meter Generation

Behind-the-Meter Generation data came from the Module E Capacity Tracking (MECT) tool. Behind-the-Meter Generation backed by thermal resources were explicitly modeled just as any other thermal generator with a monthly capability and forced outage rate. Behind-the-Meter Generation backed by intermittent resources were modeled at their expected seasonal availability.

3.2.3 Attachment Y

MISO obtained information on generating resources with approved suspensions or retirements (as of June 1, 2023) through MISO's Attachment Y process. Any resource with an approved retirement or suspension in Planning Year 2024-2025 was excluded from the year-one analysis during the months the resource has been approved to be out of service for. This same methodology is used for the four- and six-year analyses.

3.2.4 Future Generation

The LOLE model included resources with a signed and executed Generator Interconnection Agreement (as of June 1, 2022). These future resources were assigned seasonal class average forced outage rates and planned maintenance outage rates based on their resource class. Future thermal generation and upgrades were added to the LOLE model based on resource information in the MISO Generator Interconnection Queue. Resources with a planned upgrade during the study period reflect the megawatt increase for each month, beginning the month the upgrade is expected to be completed. The LOLE analysis includes future wind and solar generation, tied to the same hourly wind and solar profiles used for existing wind and solar resources in the model.

3.2.5 Intermittent Resources

Intermittent resources include solar, wind, biomass, battery storage, and run-of-river hydro. Most intermittent resources submit historical output data during seasonal peak hours, defined as hours ending 15, 16, & 17 EST for Summer, Fall, and Spring, and hours ending 8, 9, 19, & 20 for Winter. Non-CPNode wind and battery storage resources are exceptions to this and only submit historical output data for the top 8 seasonal coincident peaks for the last 3 Planning Years for which data is available. This data is averaged at the seasonal level and modeled in the LOLE analysis as seasonal effective capacity for all months within a given season. Each individual resource is modeled in the LRZ corresponding to its load obligation.

Using historical wind operational data from 253 front-of-meter wind resources from 2013 to 2022, normalized hourly capacity profiles were developed and aggregated at the LRZ level to represent hourly wind capability in the model. As a result of the LOLE analysis being based on 30 weather years (1993 – 2022), synthetic shapes were developed by Astrapé for the 1992 – 2013 period based on historical wind performance and temperatures. Once the weather and wind performance matching has been performed, the data is analyzed as a function of load to ensure the variability around the load profiles is reasonable.

Solar profiles were also developed by Astrapé using historical solar irradiance data from the NREL National Solar Radiation Database (NSRDB) from 1998 – 2022.

For more details on profile development methodology, refer to the supporting documentation Astrapé provided stakeholders at the LOLEWG detailing the development of the wind and solar profiles:
MISO Seasonal Inputs for the 2022 LOLE Study

3.2.6 Demand Response

Demand response programs and their corresponding capabilities came from the MECT tool. These resources were explicitly modeled as dispatch-limited resources. Each demand response program was modeled individually with a monthly capacity, limited by duration and the number of times each program can be called upon for each season.

3.3 MISO Load Data

The Planning Year 2024-2025 LOLE analysis used a load training process with neural net software to establish a correlated relationship in the trained and predicted load shapes between historical weather and load data. This relationship was then applied to 30 years of hourly historical load data to create 30 different load shapes for each LRZ to capture both load diversity and seasonal variations. The Zonal Coincident Peak Forecasts provided by the Load Serving Entities were used to develop zonal- and monthly-specific load forecast scaling factors which scale the average of the 30 load shapes based on provided forecasts. The results of this process are shown as the MISO System Peak Demand (Table 4-1) and LRZ Peak Demands (Table 5-1, Table 5-2, Table 5-3, & Table5-4).

Direct Control Load Management and Interruptible Demand types of demand response were explicitly included in the LOLE model as resources. Demand response is dispatched in the LOLE model to avoid load shed during simulation when all other available generation has been exhausted.

3.3.1 Weather Uncertainty

MISO has adopted a six-step load training process in order to capture the weather uncertainty associated with the most recent 50/50 load forecasts submitted by the Load Serving Entities for the development of the 30 years of hourly zonal correlated load and weather shapes in the LOLE model.

The first step of the load training process is to collect the most recent year of historical hourly net load data, as well as any hourly load reductions. Since Load Modifying Resources are modeled in the LOLE Study, the hourly load reductions are added to the net load data. MISO also collects historical temperature data from a zonal-specific weather station for the most recent weather year included in the study. Both the hourly LMR deployment and load data are taken from historical MISO energy market data for each LBA, while the historical weather data is collected from the National Oceanic and Atmospheric Administration (NOAA) for each LRZ. After collecting the data, the hourly gross load for each LRZ is calculated using the most recent five years of historical data.

The second step of the process is to normalize the five years of load data to consistent economics. This process involves zonal load growth adjustments by comparing the most recent 5 years of historical load at extreme temperatures and shifting the shapes up or down if they do not reasonably overlay on top of each other. Regression analysis is then performed at the zonal level, focusing on Summer and Winter peak periods in order to compensate for the fact that the neural net training software can occasionally over- or under-predict results for extremely high or extremely low temperatures.

The third step of the process utilizes neural net software to establish functional relationships between the most recent five years of historical weather and load data. After the load growth adjustments and regressions have been performed, the treated historical load and weather data are input into the neural net software. MISO utilizes the NeuroShell Predictor software which performs neural net training and predicting using a genetic algorithm. The neural net trains each month of zonal data individually to predict a total of 120 datasets.

In the fourth step of the process and after the neural net has finished, we check the results of the neural net at extreme temperatures to smooth out any over- or under-predicted loads by comparing against the entire 30 years of

historical correlated load and weather years. MISO looks for hours where the load is plus or minus 30% different than the previous hour and corrects those hours.

In the fifth step of the load training process, MISO undertakes extreme temperature verification on the 30 years of load shapes to ensure that the hourly load data is reasonably accurate at extremely hot or cold temperatures. This is required since there are fewer data points available at the temperature extremes when determining the neural net functional relationships. This lack of data at the extremes can result in inaccurate predictions when creating load shapes, which will need to be corrected before moving forward.

The sixth and final step of the load training process is to average the monthly peak loads of the predicted load shapes and adjust them to match each LRZ's monthly Zonal Coincident Peak Forecast provided by the Load Serving Entities for each of the study years. To calculate this adjustment, the ratio of the first year's Non-Coincident Peak Forecast to the Zonal Coincident Peak Forecast is applied to future outyears' Non-Coincident Peak Forecasts.

By adopting this methodology for capturing weather uncertainty, MISO can model multiple load shapes based on a functional relationship with weather. This modeling approach provides diversity in the load shapes, as well as in the peak loads observed within each load shape. This approach also provides the ability to capture the frequency and duration of historical severe weather patterns.

3.3.2 Economic Load Uncertainty

To account for economic load uncertainty in the Planning Year 2024-2025 LOLE model, MISO utilized a normal distribution of electric utility forecast error accounting for projected and actual Gross Domestic Product (GDP), as well as electricity usage. The historic projections for GDP growth were taken from the Congressional Budget Office (CBO), the actual GDP growth was taken from the Bureau of Economic Analysis (BEA), and the electricity usage was taken from the U.S. Energy Information Administration (EIA). Due to a lack of state-wide projected GDP data, MISO relied on aggregated United States data when calculating economic uncertainty.

To calculate the electric utility forecast error, MISO first calculated the forecast error of GDP between historical projections and actual values. The resulting GDP forecast error was then translated into electric utility forecast error by multiplying by the rate at which electric load grows in comparison to GDP. Finally, a standard deviation is calculated from the electric utility forecast error and used to create a normal distribution representing the probabilities of the load forecast errors (LFE) as shown in Table 3-3.

	LFE Levels				
	-2.0%	-1.0%	0.0%	1.0%	2.0%
Standard Deviation in LFE	Probability assigned to each LFE				
0.90%	4.8%	24.1%	42.1%	24.1%	4.8%

Table 3-3: Economic Uncertainty

3.4 External System

Firm imports from external areas to MISO are modeled at the individual resource level. The specific firm external resources were modeled with their Installed Capacity amount and their corresponding seasonal forced outage rates, or at the contracted capacity from their corresponding Power Purchase Agreement (PPA). These resources are only modeled within the system-wide MISO PRM analysis and are not modeled when calculating the zonal LRRs, as the determination of the Local Reliability Requirements is an island-type analysis. Border External Resources and Coordinating Owner External Resources are modeled as internal MISO units and are included in the PRM and LRR analyses. The external resources included as firm imports in the LOLE Study were based on the amount of capacity that was either part of a Fixed Resource Adequacy Plan (FRAP) or that offered and cleared in the Planning Year 2023-2024 Planning Resource Auction (PRA).

The LOLE analyses incorporate firm exports from MISO internal units to neighboring regions, where information was available. For units with capacity sold off-system, their monthly capacities were reduced by the megawatt amount exported. These values came from PJM's Reliability Pricing Model (RPM) as well as information on exports to other external areas taken from the Independent Market Monitor (IMM) exclusion list.

Firm exports from MISO to external areas were modeled the same as in previous years. Capacity ineligible as MISO capacity due to transactions with external areas was removed from the model. Table 3-4 shows the amount of firm imports and exports in this year's study. MISO went from being a net firm exporter to a net firm importer in the most recent PRA.

Contracts	Summer ICAP (MW)	Summer UCAP (MW)	Fall ICAP (MW)	Fall UCAP (MW)	Winter ICAP (MW)	Winter UCAP (MW)	Spring ICAP (MW)	Spring UCAP (MW)
Imports (MW)	3,217	3,052	2,865	2,758	3,771	3,613	3,247	3,105
Exports (MW)	1,142	1,086	1,160	1,124	1,125	1,062	1,159	1,094
Net	**2,075**	**1,966**	**1,705**	**1,634**	**2,646**	**2,552**	**2,088**	**2,010**

Table 3-4: Planning Year 2023-2024 Firm Imports and Exports

Non-firm imports in the Planning Year 2024-2025 LOLE Study were modeled as a probabilistic distribution of capacity value. These distributions were developed using historic seasonal NSI data which accounted for imports into MISO during emergency pricing hours. Firm imports cleared in the PRA for each Planning Year were subtracted from the NSI data to isolate the non-firm values. An additional region was included in SERVM which contained 12,000 MW of perfect generation connected to the MISO system. A distribution of the region's export capability was modeled to the upper and lower bounds. As SERVM steps through the hourly simulation, random draws on the export limits of the external region were used to represent the amount of capacity MISO could import to meet peak demand. The probability distribution of non-firm external imports used in the LOLE model has been provided in Table 3-5.

	Summer	Fall	Winter	Spring
p5	1,138	525	9	1,384
p10	1,440	903	288	1,626
p25	2,959	1,749	1,223	2,283
p50	4,260	2,601	3,292	3,717
p75	5,198	3,632	5,785	4,987
p90	5,921	4,935	8,097	6,221
p95	6,520	5,748	9,197	6,497

Table 3-5: Non-Firm External Import Distribution During Emergency Pricing Hours (MW)

3.5 Loss of Load Expectation Analysis and Metric Calculations

Upon completion of the annual LOLE Study model refresh, MISO performed probabilistic analyses to determine the seasonal PRM ICAP and PRM UCAP for Planning Year 2024-2025 as well as the seasonal Local Reliability Requirement for each of the ten Local Resource Zones. These metrics were derived through probabilistic modeling of the system, first solving to the industry standard annual LOLE risk target of 1 day in 10 years, or 0.1 day per year, and then solving to the minimum seasonal LOLE criteria of 0.01 LOLE for seasons demonstrating minimal risk.

3.5.1 Seasonal LOLE Distribution

To determine the seasonal LOLE distribution that will be used to calculate the PRM and LRRs, MISO followed the process described in Section 68A.2.1 of Module E-1 of the MISO Tariff. This process involves first solving the LOLE model to an annual value of 0.1 and then checking the seasonal distribution of the annual LOLE of 0.1. If a season had a LOLE value of at least 0.01, then it met the minimum seasonal LOLE criteria and would be set to that LOLE. If a season had less than 0.01 LOLE, additional simulations were performed until the minimum seasonal LOLE criteria of 0.01 was met.

Example: Assume the model is solved to an annual LOLE of 0.1 with 0.05 occurring in both Summer and Winter while Fall and Spring had LOLE values of 0 from this simulation. In this case, the Summer and Winter seasons would not need additional analysis since both had at least 0.01 LOLE naturally when the model was solved to an annual value of

0.1. Since Fall and Spring had 0 LOLE, they would be assigned the minimum seasonal LOLE criteria of 0.01 and additional LOLE simulations would be performed until the minimum seasonal LOLE criteria was met.

The annual distribution of LOLE across the four seasons at the industry standard of 1 day in 10 years, or 0.1 day per year, determined through the Planning Year 2024-2025 LOLE Study are shown in Table 3-6. The MISO-wide distribution results from the PRM analysis and the zonal distributions result from the LRR analyses.

Region	Summer	Fall	Winter	Spring
MISO-wide	0.1	0.01	0.01	0.01
LRZ 1	0.094	0.01	0.01	0.01
LRZ 2	0.099	0.01	0.01	0.01
LRZ 3	0.091	0.01	0.01	0.01
LRZ 4	0.022	0.01	0.075	0.01
LRZ 5	0.01	0.01	0.083	0.01
LRZ 6	0.085	0.01	0.015	0.01
LRZ 7	0.037	0.061	0.01	0.01
LRZ 8	0.014	0.01	0.078	0.01
LRZ 9	0.042	0.036	0.014	0.01
LRZ 10	0.058	0.019	0.015	0.01

Table 3-6: Planning Year 2024-2025 Seasonal LOLE Distribution

3.5.2 MISO-Wide LOLE Analysis and PRM Calculation

MISO determines the appropriate PRM for each season of the applicable Planning Year based upon probabilistic analysis of reliably serving expected demand. The probabilistic analysis will utilize a Loss of Load Expectation (LOLE) study which assumes that there are no internal transmission limitations.

To determine the PRM, the LOLE model will initially be run with no adjustments to the capacity. If the LOLE is less than the minimum seasonal LOLE criteria, a negative output unit with no outage rates will be added until the LOLE reaches the minimum seasonal LOLE criteria. This is comparable to adding load to the model. If the LOLE is greater than the minimum seasonal LOLE criteria, proxy units based on a typical combustion turbine unit of 160 MW with class average seasonal forced outage rates will be added to the model until the LOLE reaches the minimum seasonal LOLE criteria.

MISO's annual LOLE Study will calculate the seasonal PRMs based on the LOLE criteria identified in the previous section. The minimum seasonal PRM requirement will be determined using the LOLE analysis by either adding a perfectly available negative output unit or by adding proxy units until a minimum LOLE of 0.01 day per season is reached.

The formulas for the PRM values for the MISO system are:

PRM ICAP % = (Installed Capacity + Firm External Support ICAP + ICAP Adjustment to meet LOLE target – MISO Coincident Peak Demand)/MISO Coincident Peak Demand

PRM UCAP % = (Unforced Capacity + Firm External Support UCAP + UCAP Adjustment to meet LOLE target – MISO Coincident Peak Demand)/MISO Coincident Peak Demand

Where Unforced Capacity (UCAP) = Installed Capacity (ICAP) x (1 – XEFORd)

3.5.3 LRZ LOLE Analysis and Local Reliability Requirement Calculation

For the Local Resource Zone analysis, each zone included only the generating units within the LRZ (including Coordinating Owner External Resources and Border External Resources) and was modeled without consideration of the benefit of the LRZ's import capability. Similar to the MISO PRM analysis, Unforced Capacity is either added or removed in each LRZ such that an LOLE of 0.1 day per year is achieved when solving for the annual target and a minimum LOLE at least 0.01 day per season when solving for the minimum seasonal LOLE criteria. The minimum amount of Unforced Capacity above each LRZ's seasonal peak demand that was required to meet the reliability criteria was used to establish each LRZ's LRR.

The Planning Year 2024-2025 seasonal LRRs were determined using the LOLE analysis by first either adding or removing capacity until the annual LOLE reaches 0.1 day per year for the LRZ. If the LOLE is less than 0.1 day per year, a perfectly available negative output unit with no outage rates will be added until the LOLE reaches 0.1 day per year. If the LOLE is greater than 0.1 day per year, proxy units based on a typical combustion turbine unit of 160 MW with class average seasonal forced outage rates will be added to the model until the LOLE reaches 0.1 day per year.

After solving each LRZ for to the annual LOLE target of 0.1 day per year, MISO will calculate each seasonal LRR such that the summation of seasonal LOLE across the year in each zone is 1 day in 10 years, or 0.1 day per year. A minimum seasonal LOLE criteria of 0.01 will be used to calculate the LRR in seasons with less than 0.01 LOLE risk under the annual case. The seasonal Local Reliability Requirement will be determined using the LOLE analysis by either adding a perfectly available negative output unit or by adding proxy combustion turbine units until a minimum LOLE of 0.01 day per season is reached. When needed, a fraction of the marginal proxy unit was added to achieve the exact minimum seasonal LOLE criteria for the LRZ.

LRR UCAP % = (Unforced Capacity + UCAP Adjustment to meet LOLE target – Zonal Coincident Peak Demand)/Zonal Coincident Peak Demand

4 MISO System Planning Reserve Margin

4.1 Planning Year 2024-2025 MISO Planning Reserve Margin Results

For Planning Year 2024-2025, the ratio of MISO capacity to forecasted MISO system peak demand yielded a Planning Reserve Margin ICAP of 17.7 percent and a Planning Reserve Margin UCAP of 9.0 percent for the Summer season. Numerous values and calculations went into determining the MISO system PRM ICAP and PRM UCAP (Table 4-1).

MISO Planning Reserve Margin (PRM)	PY 2024-2025 Summer	PY 2024-2025 Fall	PY 2024-2025 Winter	PY 2024-2025 Spring	Formula Key
MISO System Peak Demand (MW)	124,669	112,232	104,303	99,496	[A]
Installed Capacity (ICAP) (MW)	150,187	148,755	165,924	152,092	[B]
Unforced Capacity (UCAP) (MW)	139,444	136,572	143,201	138,251	[C]
Firm External Support ICAP (MW)	3,217	2,865	3,771	3,247	[D]
Firm External Support UCAP (MW)	3,052	2,758	3,613	3,105	[E]
Adjustment to ICAP (MW)	(6,650)	(11,145)	(13,890)	(15,275)	[F]
Adjustment to UCAP (MW)	(6,650)	(11,145)	(13,890)	(15,275)	[G]
ICAP PRM Requirement (PRMR) (MW)	146,754	140,475	155,805	140,064	[H] = [B]+[D]+[F]
UCAP PRM Requirement (PRMR) (MW)	135,846	128,185	132,925	126,081	[I] = [C]+[E]+[G]
MISO PRM ICAP	**17.7%**	**25.2%**	**49.4%**	**40.8%**	[J]=[H]-[A]/[A]
MISO PRM UCAP	**9.0%**	**14.2%**	**27.4%**	**26.7%**	[K]=[I]-[A]/[A]

Table 4-1: Planning Year 2024-2025 MISO System Planning Reserve Margins

4.1.1 Additional Risk Metric Statistics

In addition to the LOLE results, SERVM has the ability to calculate several other probabilistic metrics, shown below in Table 4-2. The values for Loss of Load Hours (LOLH) and Expected Unserved Energy (EUE) are calculated at the point where the annual LOLE is at 1 day in 10 years, or 0.1 LOLE. Loss of Load Hours is defined as the number of hours during a given time period where system demand will exceed the generating capacity. Expected Unserved Energy is energy-centric and analyzes all hours of a particular Planning Year. Results are calculated in megawatt-hours (MWh). EUE is the summation of the expected number of MWh of load that will not be served in a given Planning Year as a result of demand exceeding the available generation across all deficient hours.

MISO LOLE Statistics	
Loss of Load Expectation (LOLE) [days/year]	0.100
Loss of Load Hours (LOLH) [hours/year]	0.289
Expected Unserved Energy (EUE) [megawatt-hours/year]	989.451

Table 4-2: Additional Risk Metric Statistics

4.2 Comparison of PRM Targets Across 10 Years

Figure 4-1 compares the PRM UCAP values over the last 10 Planning Years. The last two data points show the Summer PRM UCAP values following FERC acceptance of MISO's seasonal capacity construct, while the prior data points are indicative of the PRM UCAP under the annual capacity construct.

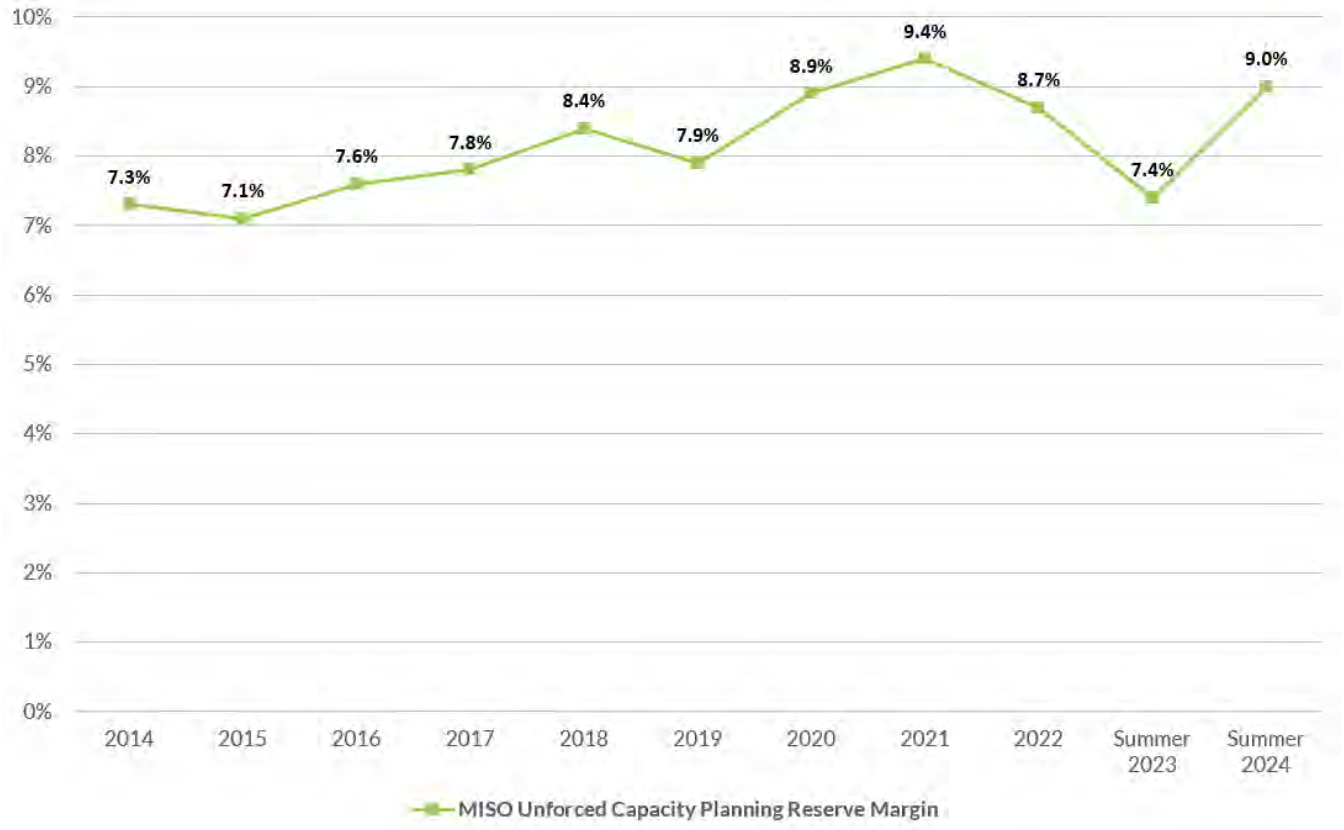


Figure 4-1: Comparison of PRM Targets Across 10 Years

5 Local Resource Zone Analysis – LRR Results

5.1 Planning Year 2024-2025 Local Resource Zone Analysis

MISO calculated the per-unit LRR of LRZ seasonal peak demand for Planning Year 2024-2025 on a seasonal basis (Table 5-1, Table 5-2, Table 5-3, & Table 5-4). The UCAP values in the seasonal LRR tables reflect the assumed seasonal UCAP within each LRZ, including Coordinating Owner External Resources and Border External Resources. The adjustments to UCAP values are the megawatt adjustments needed in each LRZ so that the seasonal LOLE criteria is met. The LRR is the summation of the zone's UCAP and adjustment to UCAP megawatts. The LRR is then divided by each LRZ's seasonal peak demand to determine the per-unit LRR UCAP. The Planning Year 2024-2025 per-unit LRR UCAP values will be multiplied by the updated seasonal peak demand forecasts submitted for the 2024-2025 PRA to determine each LRZ's LRR. Zonal peak demand timestamps for all 30 weather years modeled in SERVM are shown in Table 5-5. These peak demand timestamps are the result of the SERVM load training process and are not necessarily the actual peaks for each year.

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2024-2025 Local Reliability Requirements – Summer 2024											
Installed Capacity (ICAP) (MW)	22,031	14,680	12,032	9,635	7,942	17,184	25,178	11,749	24,009	5,748	[A]
Unforced Capacity (UCAP) (MW)	20,970	13,866	11,487	8,745	7,361	15,348	23,578	10,915	22,113	5,061	[B]
Adjustment to UCAP (MW)	380	590	1,503	3,245	3,044	5,209	980	692	2,502	2,093	[C]
LRR (UCAP) (MW)	21,351	14,456	12,990	11,990	10,405	20,557	24,558	11,607	24,615	7,153	[D]=[B]+[C]
Peak Demand (MW)	18,854	12,990	10,165	9,288	7,814	17,279	21,160	8,336	21,689	4,712	[E]
LRR UCAP per-unit of LRZ Peak Demand	**113.2%**	**111.3%**	**127.8%**	**129.1%**	**133.1%**	**119.0%**	**116.1%**	**139.2%**	**113.5%**	**151.8%**	[F]=[D]/[E]

Table 5-1: Planning Year 2024-2025 LRZ Local Reliability Requirements for Summer 2024

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2024-2025 Local Reliability Requirements – Fall 2024											
Installed Capacity (ICAP) (MW)	21,604	14,808	11,765	9,543	8,092	17,140	24,487	11,568	23,995	5,753	[A]
Unforced Capacity (UCAP) (MW)	20,167	13,723	11,151	8,300	7,428	15,491	22,832	10,923	21,477	5,081	[B]
Adjustment to UCAP (MW)	-847	-402	1,007	2,303	2,486	4,040	956	427	2,440	2,041	[C]
LRR (UCAP) (MW)	19,320	13,321	12,157	10,604	9,914	19,531	23,787	11,349	23,917	7,122	[D]=[B]+[C]
Peak Demand (MW)	15,645	11,113	9,037	8,014	6,880	15,537	18,142	7,585	20,095	4,272	[E]
LRR UCAP per-unit of LRZ Peak Demand	**123.5%**	**119.9%**	**134.5%**	**132.3%**	**144.1%**	**125.7%**	**131.1%**	**149.6%**	**119.0%**	**166.7%**	[F]=[D]/[E]

Table 5-2: Planning Year 2024-2025 LRZ Local Reliability Requirements for Fall 2024

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2024-2025 Local Reliability Requirements – Winter 2024-2025											
Installed Capacity (ICAP) (MW)	24,143	15,861	16,846	11,141	8,737	18,366	26,118	12,347	26,054	6,312	[A]
Unforced Capacity (UCAP) (MW)	21,941	13,894	15,443	7,142	6,199	14,464	23,949	11,108	23,558	5,504	[B]
Adjustment to UCAP (MW)	143	-500	1,432	3,053	2,936	4,899	-1,153	651	2,353	1,968	[C]
LRR (UCAP) (MW)	22,084	13,394	16,874	10,195	9,136	19,363	22,796	11,760	25,911	7,472	[D]=[B]+[C]
Peak Demand (MW)	15,312	9,830	8,413	7,622	7,110	15,779	14,186	7,539	19,513	4,009	[E]
LRR UCAP per-unit of LRZ Peak Demand	**144.2%**	**136.3%**	**200.6%**	**133.8%**	**128.5%**	**122.7%**	**160.7%**	**156.0%**	**132.8%**	**186.4%**	[F]=[D]/[E]

Table 5-3: Planning Year 2024-2025 LRZ Local Reliability Requirements for Winter 2024-2025

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2024-2025 Local Reliability Requirements – Spring 2025											
Installed Capacity (ICAP) (MW)	21,887	15,164	12,479	10,301	8,322	17,448	24,391	11,755	24,434	5,911	[A]
Unforced Capacity (UCAP) (MW)	20,576	14,079	11,568	8,579	7,082	15,812	22,221	10,549	22,516	5,269	[B]
Adjustment to UCAP (MW)	-1,500	-260	730	2,652	2,957	4,098	-920	292	2,491	2,077	[C]
LRR (UCAP) (MW)	19,076	13,819	12,298	11,231	10,040	19,909	21,301	10,841	25,007	7,346	[D]=[B]+[C]
Peak Demand (MW)	14,356	10,137	8,034	6,756	6,206	14,523	16,109	6,733	18,746	3,911	[E]
LRR UCAP per-unit of LRZ Peak Demand	**132.9%**	**136.3%**	**153.1%**	**166.2%**	**161.8%**	**137.1%**	**132.2%**	**161.0%**	**133.4%**	**187.8%**	[F]=[D]/[E]

Table 5-4: Planning Year 2024-2025 LRZ Local Reliability Requirements for Spring 2025

Weather Year Time of Peak Demand (ESTHE)	MISO	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS
1993	7/27/93 17:00	8/11/93 17:00	8/27/93 14:00	8/22/93 19:00	7/17/93 17:00	7/27/93 16:00	7/25/93 16:00	7/9/93 15:00	7/31/93 17:00	8/14/93 16:00	7/31/93 18:00
1994	7/6/94 15:00	6/14/94 17:00	6/15/94 17:00	7/19/94 17:00	7/5/94 17:00	7/19/94 18:00	1/19/94 6:00	6/18/94 17:00	6/29/94 18:00	8/14/94 17:00	7/5/94 17:00
1995	7/13/95 17:00	7/13/95 18:00	7/13/95 16:00	7/14/95 17:00	7/14/95 17:00	7/13/95 16:00	7/13/95 17:00	7/13/95 17:00	8/17/95 14:00	7/27/95 17:00	7/12/95 15:00
1996	6/29/96 17:00	8/6/96 17:00	6/29/96 17:00	7/18/96 17:00	7/18/96 18:00	7/18/96 17:00	7/19/96 17:00	8/7/96 15:00	7/20/96 15:00	2/5/96 7:00	7/3/96 18:00
1997	7/26/97 16:00	7/16/97 16:00	7/16/97 17:00	7/25/97 18:00	7/18/97 16:00	7/26/97 17:00	7/26/97 16:00	7/16/97 16:00	7/25/97 18:00	8/16/97 16:00	7/25/97 18:00
1998	7/20/98 16:00	7/13/98 16:00	6/25/98 18:00	7/20/98 18:00	7/20/98 18:00	7/19/98 16:00	7/19/98 17:00	6/25/98 18:00	7/6/98 17:00	8/28/98 18:00	8/27/98 15:00
1999	7/30/99 14:00	7/25/99 15:00	7/13/95 16:00	7/30/99 18:00	7/18/99 22:00	7/30/99 17:00	7/26/97 16:00	7/30/99 14:00	7/25/99 17:00	8/14/99 18:00	8/20/99 18:00
2000	8/31/00 16:00	6/8/00 19:00	9/1/00 17:00	8/31/00 16:00	9/1/00 15:00	8/17/00 16:00	9/1/00 15:00	9/1/00 14:00	7/19/00 17:00	8/30/00 16:00	8/30/00 17:00
2001	8/8/01 16:00	8/7/01 16:00	8/9/01 16:00	7/31/01 16:00	7/23/01 17:00	7/23/01 17:00	8/7/01 17:00	8/8/01 16:00	7/11/01 16:00	7/10/01 16:00	7/20/01 17:00
2002	7/3/02 16:00	7/6/02 18:00	8/1/02 15:00	7/20/02 18:00	7/5/02 17:00	8/1/02 16:00	8/3/02 16:00	7/3/02 16:00	7/9/02 17:00	8/2/02 19:00	10/4/02 15:00
2003	8/21/03 16:00	8/24/03 17:00	8/21/03 16:00	7/26/03 18:00	8/21/03 16:00	8/21/03 18:00	8/27/03 17:00	8/21/03 17:00	7/18/03 14:00	8/10/03 16:00	7/17/03 17:00
2004	7/22/04 16:00	6/7/04 17:00	7/22/04 16:00	7/20/04 17:00	7/13/04 17:00	7/13/04 16:00	1/31/04 9:00	7/22/04 16:00	7/14/04 17:00	7/24/04 17:00	7/25/04 15:00
2005	7/24/05 17:00	7/17/05 17:00	7/24/05 16:00	7/25/05 17:00	7/24/05 16:00	7/24/05 18:00	7/25/05 17:00	7/24/05 18:00	8/21/05 18:00	7/25/05 16:00	8/21/05 15:00
2006	7/31/06 17:00	7/31/06 17:00	8/1/06 17:00	7/19/06 18:00	7/31/06 18:00	7/31/06 16:00	7/31/06 16:00	7/31/06 16:00	7/31/93 17:00	8/15/06 18:00	7/16/06 15:00
2007	8/1/07 17:00	7/26/07 15:00	8/2/07 15:00	7/17/07 17:00	8/15/07 18:00	8/15/07 18:00	8/29/07 17:00	7/31/07 18:00	8/17/95 14:00	8/14/07 15:00	8/14/07 15:00
2008	7/16/08 17:00	7/11/08 18:00	7/17/08 17:00	8/3/08 17:00	7/20/08 17:00	7/20/08 16:00	8/23/08 16:00	8/24/08 12:00	8/17/95 14:00	7/20/08 17:00	7/27/08 16:00
2009	6/25/09 16:00	6/22/09 19:00	7/28/09 16:00	7/24/09 18:00	8/9/09 16:00	8/9/09 16:00	1/16/09 8:00	6/25/09 16:00	6/22/09 16:00	7/2/09 16:00	7/2/09 18:00

Weather Year Time of Peak Demand (ESTHE)	MISO	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS
2010	8/10/10 17:00	8/8/10 18:00	8/20/10 14:00	7/17/10 19:00	7/15/10 15:00	8/3/10 16:00	8/2/91 18:00	9/1/10 17:00	8/17/95 14:00	8/1/10 17:00	8/2/10 17:00
2011	7/20/11 18:00	6/7/11 19:00	7/13/95 16:00	7/20/11 16:00	9/1/11 16:00	8/31/11 16:00	7/26/97 16:00	7/20/11 19:00	7/31/93 17:00	7/2/11 17:00	7/10/11 18:00
2012	7/6/12 17:00	7/6/12 18:00	7/13/95 16:00	7/7/12 16:00	7/7/12 17:00	7/25/12 18:00	7/26/97 16:00	7/6/12 17:00	7/30/12 17:00	6/26/12 16:00	7/3/12 15:00
2013	7/19/13 16:00	7/18/13 19:00	8/27/13 16:00	8/30/13 16:00	9/11/13 16:00	8/31/13 17:00	8/31/13 15:00	7/19/13 14:00	6/27/13 18:00	8/7/13 16:00	8/8/13 17:00
2014	7/22/14 16:00	7/22/14 17:00	7/22/14 16:00	7/22/14 16:00	9/5/14 16:00	7/26/14 15:00	2/7/14 9:00	7/22/14 17:00	7/27/14 17:00	8/23/14 16:00	7/26/14 17:00
2015	7/29/15 16:00	8/14/15 15:00	8/14/15 17:00	7/13/15 15:00	9/3/15 16:00	7/13/15 16:00	7/18/15 17:00	8/2/15 16:00	8/7/15 18:00	8/10/15 16:00	7/30/15 16:00
2016	7/20/16 15:00	7/21/16 17:00	8/10/16 17:00	7/22/16 16:00	9/22/16 16:00	7/23/16 17:00	6/11/16 14:00	8/10/16 14:00	7/20/16 13:00	9/1/16 16:00	7/20/16 15:00
2017	7/20/17 16:00	7/6/17 17:00	6/12/17 14:00	7/21/17 17:00	9/26/17 15:00	7/12/17 15:00	9/26/17 16:00	6/12/17 14:00	7/21/17 15:00	8/19/17 15:00	7/20/17 15:00
2018	6/29/18 15:00	6/29/18 15:00	6/29/18 15:00	5/28/18 14:00	9/5/18 15:00	8/6/18 16:00	9/5/18 16:00	9/5/18 15:00	1/17/18 6:00	1/17/18 6:00	9/19/18 16:00
2019	7/19/19 14:00	7/19/19 18:00	7/19/19 16:00	7/19/19 14:00	9/12/19 16:00	10/1/19 15:00	9/13/19 16:00	7/19/19 13:00	8/13/19 14:00	10/4/19 15:00	10/2/19 16:00
2020	7/9/20 15:00	7/2/20 17:00	8/27/20 14:00	7/8/20 14:00	7/8/20 15:00	7/11/20 15:00	8/25/20 15:00	7/9/20 15:00	7/12/20 15:00	7/11/20 15:00	9/4/20 16:00
2021	8/24/21 15:00	7/27/21 16:00	8/10/21 15:00	7/28/21 16:00	8/27/21 15:00	8/25/21 16:00	8/24/21 16:00	8/24/21 15:00	8/10/21 14:00	8/23/21 16:00	7/29/21 14:00
2022	7/19/22 17:00	7/19/22 18:00	6/15/22 16:00	7/23/22 16:00	8/13/22 18:00	7/23/22 15:00	7/11/22 17:00	6/21/22 17:00	7/8/22 16:00	9/21/22 17:00	8/15/22 17:00

Table 5-5: Modeled Peak Demand Days/Hours by Local Resource Zone

6 Appendix A: Comparison of Planning Year 2023-2024 to Planning Year 2024-2025

Multiple study sensitivity analyses were performed to compute changes in the PRM target on a UCAP basis for each season, from Planning Year 2023-2024 to Planning Year 2024-2025. These sensitivities included one-off incremental changes of input parameters to quantify how each change affected the PRM result independently. Note the impact of the incremental PRM changes from Planning Year 2023-2024 to Planning Year 2024-2025 in the waterfall charts below (Figure A-1, Figure A-2, Figure A-3, & Figure A-4). The following subsections provide more details around each of the sensitivities.

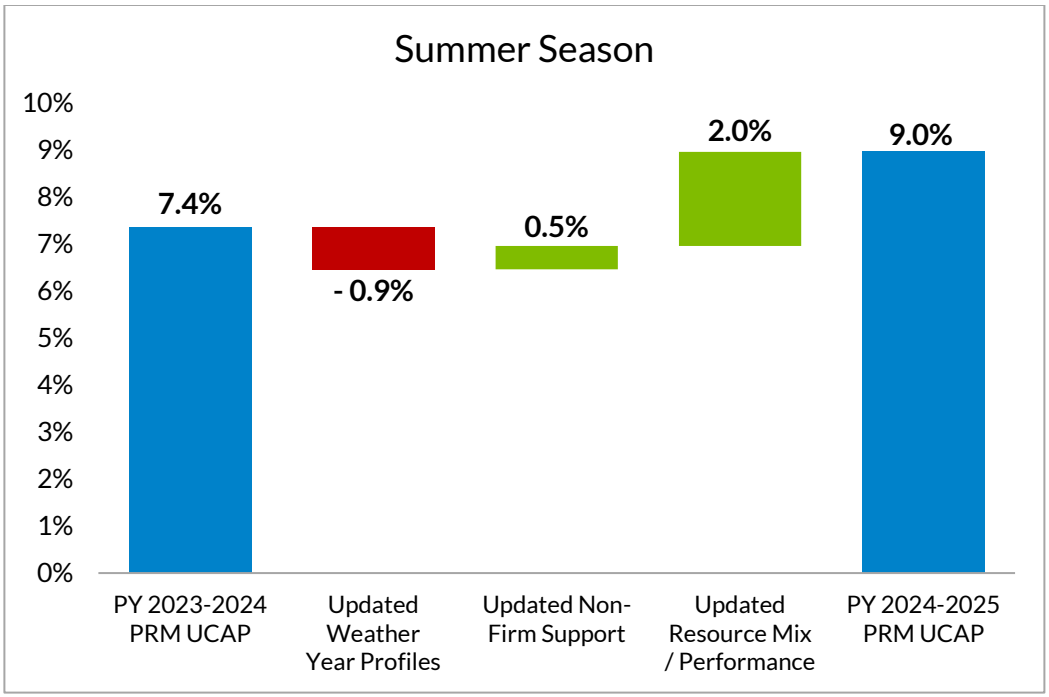


Figure A-1: Waterfall Chart of Summer PRM UCAP from PY 2023-2024 to PY 2024-2025

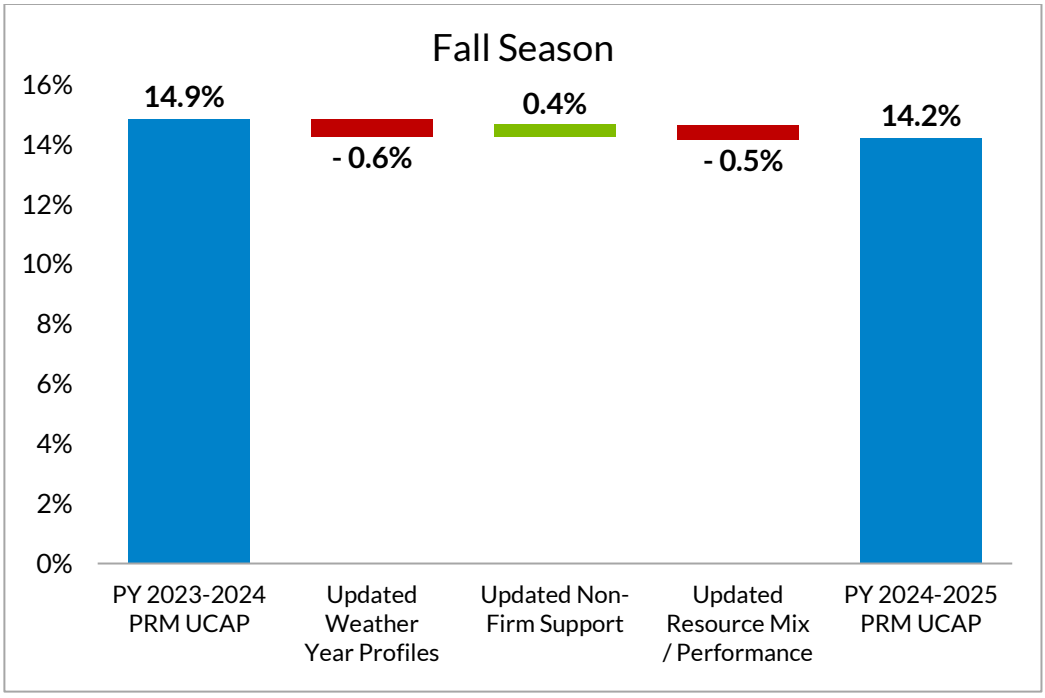


Figure A-2: Waterfall Chart of Fall PRM UCAP from PY 2023-2024 to PY 2024-2025

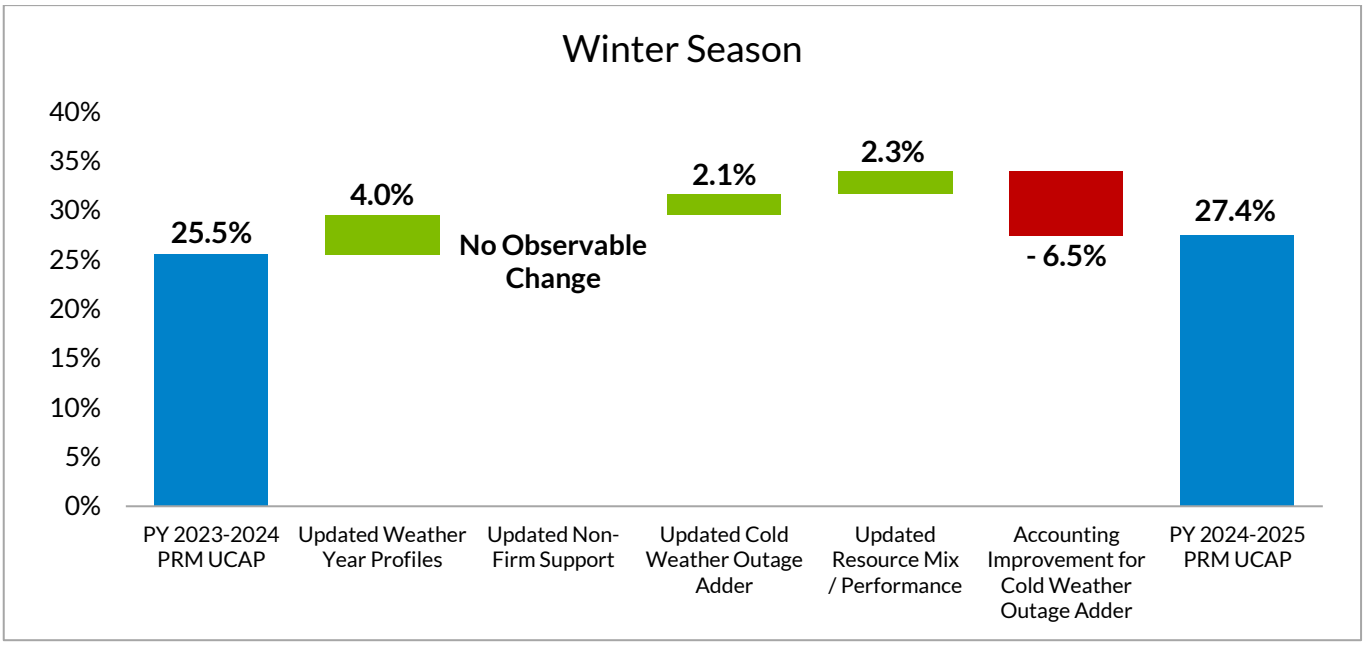


Figure A-3: Waterfall Chart of Winter PRM UCAP from PY 2023-2024 to PY 2024-2025

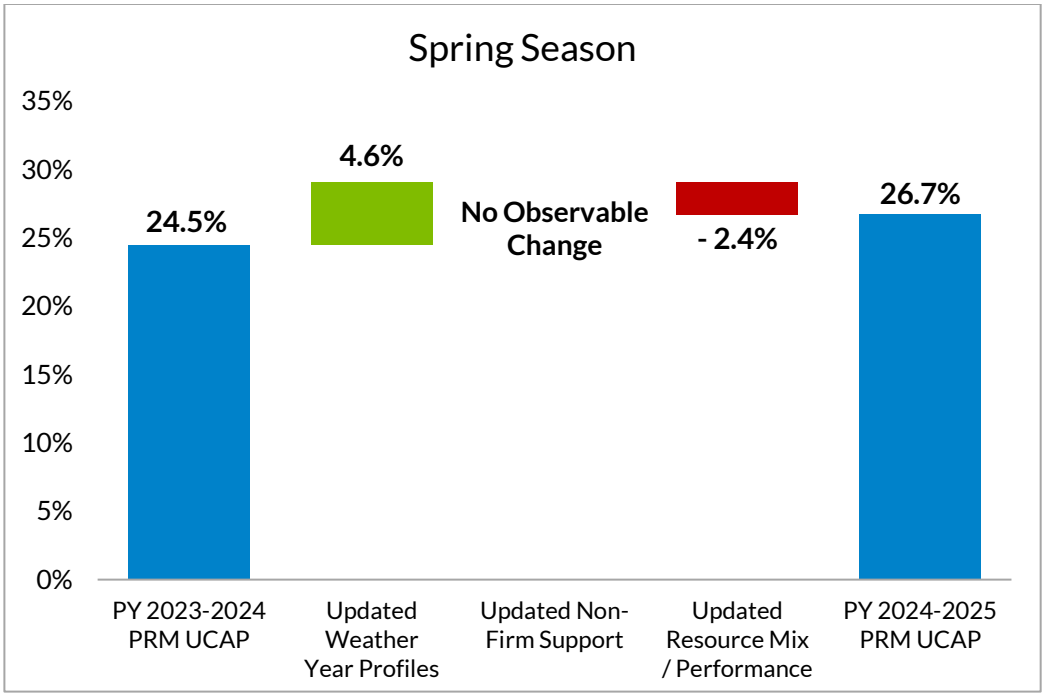


Figure A-4: Waterfall Chart of Spring PRM UCAP from PY 2023-2024 to PY 2024-2025

6.1 Waterfall Chart Details

6.1.1 Updated Weather Year Profiles

With the annual refresh to the LOLE model, the oldest weather year is dropped off and a new weather year is added. Previously, only load shapes were tied to the weather years. Now, with the addition to the model of hourly profiles for renewables and the cold weather outage adder, it is no longer possible to isolate just the updated load profiles as stakeholders may be used to seeing in prior reports.

6.1.2 Updated Non-Firm Support

The probabilistic distribution of seasonal non-firm support is not tied to any specific weather years and is the next input dataset to be replaced in the LOLE model.

6.1.3 Updated Resource Mix / Performance

Changes in resource capability from Planning Year 2023-2024 are primarily driven by a methodology change in the Planning Resource Auction (PRA) to request from generation owners seasonally corrected Generation Verification Test Capacity (GVTC). Other drivers include updated seasonal forced outage rates, updated annualized planned maintenance outage rates, new units, retirements, suspensions, and changes in the resource mix. There was also a modeling improvement to make battery storage use-limited in the model that would also be a driver for change.

6.1.4 Updated Cold Weather Outage Adder (Winter only)

The isolated impact on the system-wide PRM requirement of modeling outage adder during extreme cold temperatures was found to be 6,710 MW. When compared to the cold weather outage adder from the prior year study, this represents an approximately 2.2 GW impact increase year-over-year.

6.1.5 Accounting Improvement for Cold Weather Outage Adder (Winter only)

The modeling of additional forced outages in the Winter season due to the adder induces a more elevated volume of forced outages in the model beyond the average Winter forced outage rates, but this was previously not reflected in the PRM and LRR accounting. ELCC-type analysis was performed to quantify the system-wide impact of modeling the cold weather outage adder profiles. Including these additional Winter forced outages in the numerator of the requirement calculations as a reduction in total Unforced Capacity lowers Winter requirements.

7 Appendix B: Increased Winter Thermal Capability Sensitivity

As requested by stakeholders at the LOLEWG, MISO performed a sensitivity for the Winter season to better understand the impact of including increased Winter capabilities of certain thermal resources to the Winter Planning Reserve Margin Requirement. For this sensitivity, MISO utilized generation owners' seasonal GVTC values for the Planning Year 2023-2024 Planning Resource Auction and scaled the thermal Winter capabilities by, approximately, an additional 20% to see how the adjustment to capacity in the model changed to maintain the same LOLE criteria. This sensitivity demonstrated that there are diminishing returns for the ability to reduce risk in the model when there is a saturated increase in resource capability. Increased capability across the same set of resources may not translate to increased availability, as non-risk hours that already had excess generation may see no benefit whereas risk hours may be exacerbated, or more risk hours may emerge, from an elevated volume of outages when forced and planned maintenance outage rates are applied to a higher thermal capability.

8 Appendix C: Capacity Import Limit Tier 1 & 2 Source Subsystem Definitions

MISO Local Resource Zone 1

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
XEL / 600	ITCM / 627	WEC / 295
MP / 608	ALTE / 694	MIUP / 296
SMMPA / 613	WPS / 696	AMMO / 356
GRE / 615	MGE / 697	AMIL / 357
OTP / 620		MPW / 633
MDU / 661		MEC / 635
BEPC-MISO / 663		
DPC / 680		

MISO Local Resource Zone 2

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #	
WEC / 295	METC / 218	NIPS / 217	OTP / 620
MIUP / 296	XEL / 600	ITCT / 219	MPW / 633
ALTE / 694	MP / 608	AMMO / 356	MEC / 635
WPS / 696	ITCM / 627	AMIL / 357	
MGE / 697	DPC / 680	SMMPA / 613	
UPPC / 698		GRE / 615	

MISO Local Resource Zone 3

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #	
ITCM / 627	AMMO / 356	DEI / 208	MP / 608
MPW / 633	AMIL / 357	NIPS / 217	GRE / 615
MEC / 635	XEL / 600	WEC / 295	OTP / 620
	SMMPA / 613	CWLP / 360	WPS / 696
	DPC / 680	SIPC/ 361	MGE / 697
	ALTE / 694	GLHB / 362	

MISO Local Resource Zone 4

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #	
AMIL / 357	DEI / 208	HE / 207	SMMPA / 613
CWLP / 360	NIPS / 217	SIGE / 210	MPW / 633
SIPC / 361	BREC / 314	IPL / 216	DPC / 680
GLHB / 362	AMMO / 356	METC / 218	ALTE / 694
GLH / 373	ITCM / 627	HMPL / 315	
	MEC / 635	XEL / 600	

MISO Local Resource Zone 5

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #	
CWLD / 333	AMIL / 357	DEI / 208	SMMPA / 613
AMMO / 356	GLHB / 362	NIPS / 217	MPW / 633
	ITCM / 627	CWLP / 360	DPC / 680
	MEC / 635	SIPC / 361	ALTE / 694
		XEL / 600	

MISO Local Resource Zone 6

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
HE / 207	METC / 218	ITCT / 219
DEI / 208	AMIL / 357	MIUP / 296
SIGE / 210	SIPC / 361	AMMO / 356
IPL / 216		CWLP / 360
NIPS / 217		GLHB / 362
BREC / 314		ITCM / 627
HMPL / 315		MEC / 635

MISO Local Resource Zone 7

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
METC / 218	NIPS / 217	DEI / 208
ITCT / 219	MIUP / 296	WEC / 295
		AMIL / 356
		WPS / 696
		UPPC / 698

MISO Local Resource Zone 8

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
EES-EAI / 327	EES-EMI / 326	LAGN / 332
	EES / 351	Cooperative Energy / 349
		CLEC / 502
		LAFA / 503

MISO Local Resource Zone 9

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
LAGN / 332	EES-EMI / 326	Cooperative Energy / 349
EES / 351	EES-EAI / 327	
CLEC / 502		
LAFA / 503		
LEPA / 504		

MISO Local Resource Zone 10

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
EES-EMI / 326	EES-EAI / 327	LAGN / 332
Cooperative Energy / 349	EES / 351	CLEC / 502
		LAFA / 503

9 Appendix D: Compliance Conformance Table

Requirements under: Standard BAL-502-RF-03	Response
R1 The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall:	The Planning Year 2024-2025 LOLE Study Report is the annual Resource Adequacy Analysis for the peak season of June 2024 through May 2025 and beyond. Analysis of Planning Year 2024-2025 is in Sections 4.1 and 5.1. Analysis of Future Years 2025-2034 are included in Appendix F as an addendum to the study report.
R1.1 Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year[1] analyzed (per R1.2) being equal to 0.1. (This is comparable to a "one day in 10 years" criterion).	Section 3.5 of this report outlines the utilization of LOLE in the reserve margin determination. "These metrics were derived through probabilistic modeling of the system, first solving to the industry standard annual LOLE risk target of 1 day in 10 years, or 0.1 day per year, and then solving to the minimum seasonal LOLE criteria of 0.01 LOLE for seasons demonstrating minimal risk."
R1.1.1 The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the loss of Load probability.	Section 3.3 of this report. "Direct Control Load Management and Interruptible Demand types of demand response were explicitly included in the LOLE model as resources. Demand response is dispatched in the LOLE model to avoid load shed during simulation when all other available generation has been exhausted."
R1.1.2 The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median forecast peak Net Internal Demand (planning reserve margin).	Section 4.1 of this report. "…the ratio of MISO capacity to forecasted MISO system peak demand yielded a planning ICAP reserve margin…"
R1.2 Be performed or verified separately for each of the following planning years.	Covered in the segmented R1.2 responses below.
R1.2.1 Perform an analysis for Year One.	In Sections 4.1 and 5.1, a full analysis was performed for Planning Year 2024-2025.
R1.2.2 Perform an analysis or verification at a minimum for one year in the 2 through 5-year period and at a minimum one year in the 6 though 10 year period.	Analysis of Planning Years 2027-2028 and 2029-2030 are included in Appendix F as an addendum to the study report.

Requirements under: Standard BAL-502-RF-03	Response
R1.2.2.1 If the analysis is verified, the verification must be supported by current or past studies for the same planning year.	Analysis was performed.
R1.3 Include the following subject matter and documentation of its use:	Covered in the segmented R1.3 responses below.
R1.3.1 Load forecast characteristics: • Median (50:50) forecast peak load • Load forecast uncertainty (reflects variability in the Load forecast due to weather and regional economic forecasts) • Load diversity • Seasonal Load variations • Daily demand modeling assumptions (firm, interruptible) • Contractual arrangements concerning curtailable/Interruptible Demand	Median forecasted load – In Section 3.3 of this report: "The sixth and final step of the load training process is to average the monthly peak loads of the predicted load shapes and adjust them to match each LRZ's monthly Zonal Coincident Peak Forecast provided by the Load Serving Entities for each of the study years." Load Forecast Uncertainty – A detailed explanation of the weather and economic uncertainties is given in Section 3.3. Load Diversity / Seasonal Load Variations — In Section 3.3 of this report: "MISO has adopted a six-step load training process in order to capture the weather uncertainty associated with the most recent 50/50 load forecasts submitted by the Load Serving Entities for the development of the 30 years of hourly zonal correlated load and weather shapes in the LOLE model. The third step of the process utilizes neural net software to establish functional relationships between the most recent five years of historical weather and load data." Demand Modeling Assumptions / Curtailable and Interruptible Demand — All Load Modifying Resources must first meet registration requirements through Module E of the MISO Tariff. As stated in Section 3.2.6: "Each demand response program was modeled individually with a monthly capability, limited by duration, and the number of times each program can be called upon for each season."

Requirements under: Standard BAL-502-RF-03	Response
R1.3.2 Resource characteristics: • Historic resource performance and any projected changes • Seasonal resource ratings • Modeling assumptions of firm capacity purchases from and sales to entities outside the Planning Coordinator area • Resource planned outage schedules, deratings, and retirements • Modeling assumptions of intermittent and energy limited resource such as wind and cogeneration • Criteria for including planned resource additions in the analysis	Section 3.2 details how historic performance data and seasonal ratings are gathered and includes discussion of future units and the modeling assumptions for intermittent capacity resources. A more detailed explanation of firm capacity purchases and sales is in Section 3.4.
R1.3.3 Transmission limitations that prevent the delivery of generation reserves	Annual MTEP deliverability analysis identifies transmission limitations preventing delivery of generation reserves. Additionally, Section 2 of this report details the transfer analysis to capture transmission constraints limiting capacity transfers.
R1.3.3.1 Criteria for including planned Transmission Facility additions in the analysis	Inclusion of the planned transmission addition assumptions is detailed in Section 2.2.3.
R1.3.4 Assistance from other interconnected systems including multi-area assessment considering Transmission limitations into the study area.	Section 3.4 provides the analysis on the treatment of external support assistance and limitations.

Requirements under: Standard BAL-502-RF-03	Response
R1.4 Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included: • Availability and deliverability of fuel • Common mode outages that affect resource availability • Environmental or regulatory restrictions of resource availability • Any other demand (Load) response programs not included in R1.3.1 • Sensitivity to resource outage rates • Impacts of extreme weather/drought conditions that affect unit availability • Modeling assumptions for emergency operation procedures used to make reserves available • Market resources not committed to serving Load (uncommitted resources) within the Planning Coordinator area	Fuel availability, environmental restrictions, common mode outage, and extreme weather conditions are all part of the historical availability performance data that goes into the unit's EFORd statistic. The use of the EFORd values is covered in Section 3.2.1. The use of demand response programs is mentioned in Section 3.2.6. The effects of resource outage characteristics on the reserve margin are outlined in Section 3.5.2 by examining the difference between PRM ICAP and PRM UCAP values.
R1.5 Consider Transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included	Transmission maintenance schedules were not included in the analysis of the transmission system due to the limited availability of reliable long-term maintenance schedules and minimal impact to the results of the analysis. However, Section 2 treats worst-case theoretical outages by performing First Contingency Total Transfer Capability (FCTTC) analysis for each LRZ, by modeling NERC Category P0 (system intact) and Category P1 (N-1) contingencies.
R1.6 Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis	MISO internal resources are among the quantities documented in the tables provided in Sections 4 and 5.
R1.7 Document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis	MISO load is among the quantities documented in the tables provided in Sections 4 and 5.
R2 The Planning Coordinator shall annually document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis.	In Sections 4 and 5, the peak load and estimated amount of resources for Planning Year 2024-2025 are shown. This includes the detail for each transmission constrained sub-area.
R2.1 This documentation covers each of the years in year one through ten.	Appendix F covers the future Planning Years.

Requirements under: Standard BAL-502-RF-03	Response
R2.2 This documentation includes the Planning Reserve margin calculated per requirement R1.1 for each of the three years in the analysis.	The prompt Planning Year seasonal PRM values are covered in Sections 4.1. The outyear Planning Years 4 (2027-2028) and 6 (2029-2030) are covered in Appendix F.
R2.3 The documentation as specified per requirement R2.1 and R2.2 shall be publicly posted no later than 30 calendar days prior to the beginning of Year One.	The final Planning Year 2024-2025 LOLE Study Report was posted publicly in December 2023, several months prior to the start of the applicable Planning Year.
R3 The Planning Coordinator shall identify any gaps between the needed amount of planning reserves defined in Requirement R1, Part 1.1 and the projected planning reserves documented in Requirement R2.	Sections 4 and 5 show the differences between the needed amount and the projected planning reserves for Planning Year 2024-2025. The needed amount of planning reserves for the outyear Planning Years 4 (2027-2028) and 6 (2029-2030) are covered in Appendix F.

10 Appendix E: Acronyms List Table

CEL	Capacity Export Limit
CIL	Capacity Import Limit
CPNode	Commercial Pricing Node
DF	Distribution Factor
EFORd	Equivalent Forced Outage Rate demand
ELCC	Effective Load Carrying Capability
ERZ	External Resource Zone
EUE	Expected Unserved Energy
FERC	Federal Energy Regulatory Commission
FCITC	First Contingency Incremental Transfer Capability
FCTTC	First Contingency Total Transfer Capability
GADS	Generator Availability Data System
GLT	Generation Limited Transfer
GVTC	Generation Verification Test Capacity
ICAP	Installed Capacity
LBA	Local Balancing Authority
LCR	Local Clearing Requirement
LFE	Load Forecast Error
LFU	Load Forecast Uncertainty
LOLE	Loss of Load Expectation
LOLEWG	Loss of Load Expectation Working Group
LRR	Local Reliability Requirement
LRZ	Local Resource Zones
LSE	Load Serving Entity
MARS	Multi-Area Reliability Simulation
MECT	Module E Capacity Tracking
MISO	Midcontinent Independent System Operator
MOD	Model on Demand
MTEP	MISO Transmission Expansion Plan
MW	Megawatt
MWh	Megawatt hours
NERC	North American Electric Reliability Corporation

PRA	Planning Resource Auction
PRM	Planning Reserve Margin
PRM ICAP	PRM Installed Capacity
PRM UCAP	PRM Unforced Capacity
PRMR	Planning Reserve Margin Requirement
PSS E	Power System Simulator for Engineering
RCF	Reciprocal Coordinating Flowgate
RDS	Redispatch
RPM	Reliability Pricing Model
SERVM	Strategic Energy & Risk Valuation Model
SPS	Special Protection Scheme
TARA	Transmission Adequacy and Reliability Assessment
UCAP	Unforced Capacity
XEFORd	Equivalent Forced Outage Rate demand with adjustment to exclude events outside management control
ZIA	Zonal Import Ability
ZEA	Zonal Export Ability

11 Appendix F: Outyear PRM Results

Beyond the prompt Planning Year 2024-2025, LOLE analyses were performed for the four-year-out Planning Year of 2027-2028, and the six-year-out Planning Year of 2029-2030. Tables 11-1 and 11-2 show the capacity and demand values that went into the MISO system seasonal Planning Reserve Margin for outyears four and six, respectively. Tables 11-3, 11-4, 10-5, and 11-6 show the seasonal outyear PRM projections ten years out based on future capacity and demand assumptions.

11.1 Planning Year 2027-2028 MISO Planning Reserve Margin Results

For Planning Year 2027-2028, the ratio of MISO capacity to forecasted MISO system peak demand yielded a Planning Reserve Margin ICAP of 18.9 percent and a Planning Reserve Margin UCAP of 9.6 percent for the Summer season. Numerous values and calculations went into determining the four-year-out MISO system seasonal PRM ICAP and PRM UCAP (Table 11-1).

MISO Planning Reserve Margin (PRM)	PY 2027-2028 Summer	PY 2027-2028 Fall	PY 2027-2028 Winter	PY 2027-2028 Spring	Formula Key
MISO System Peak Demand (MW)	126,218	113,712	105,726	100,853	[A]
Installed Capacity (ICAP) (MW)	158,145	157,720	170,335	164,536	[B]
Unforced Capacity (UCAP) (MW)	146,508	144,619	147,165	150,185	[C]
Firm External Support ICAP (MW)	3,217	2,865	3,771	3,247	[D]
Firm External Support UCAP (MW)	3,052	2,758	3,613	3,105	[E]
Adjustment to ICAP (MW)	(11,250)	(15,600)	(16,750)	(19,400)	[F]
Adjustment to UCAP (MW)	(11,250)	(15,600)	(16,750)	(19,400)	[G]
ICAP PRM Requirement (PRMR) (MW)	150,112	144,984	157,356	148,383	[H] = [B]+[D]+[F]
UCAP PRM Requirement (PRMR) (MW)	138,309	131,777	134,028	133,890	[I] = [C]+[E]+[G]
MISO PRM ICAP	**18.9%**	**27.5%**	**48.8%**	**47.1%**	[J]=[H]-[A]/[A]
MISO PRM UCAP	**9.6%**	**15.9%**	**26.8%**	**32.8%**	[K]=[I]-[A]/[A]

Table 11-1: Planning Year 2027-2028 MISO System Planning Reserve Margins

11.2 Planning Year 2029-2030 MISO Planning Reserve Margin Results

For Planning Year 2029-2030, the ratio of MISO capacity to forecasted MISO system peak demand yielded a Planning Reserve Margin ICAP of 19.0 percent and a Planning Reserve Margin UCAP of 9.4 percent for the Summer season. Numerous values and calculations went into determining the six-year-out MISO system seasonal PRM ICAP and PRM UCAP (Table 11-2).

MISO Planning Reserve Margin (PRM)	**PY 2029-2030** Summer	**PY 2029-2030** Fall	**PY 2029-2030** Winter	**PY 2029-2030** Spring	**Formula Key**
MISO System Peak Demand (MW)	127,512	114,908	106,860	101,932	[A]
Installed Capacity (ICAP) (MW)	167,877	165,485	177,850	173,032	[B]
Unforced Capacity (UCAP) (MW)	155,733	151,779	153,853	157,958	[C]
Firm External Support ICAP (MW)	3,217	2,865	3,771	3,247	[D]
Firm External Support UCAP (MW)	3,052	2,758	3,613	3,105	[E]
Adjustment to ICAP (MW)	(19,330)	(21,830)	(22,500)	(25,000)	[F]
Adjustment to UCAP (MW)	(19,330)	(21,830)	(22,500)	(25,000)	[G]
ICAP PRM Requirement (PRMR) (MW)	151,764	146,520	159,121	151,279	[H] = [B]+[D]+[F]
UCAP PRM Requirement (PRMR) (MW)	139,454	132,707	134,967	136,063	[I] = [C]+[E]+[G]
MISO PRM ICAP	**19.0%**	**27.5%**	**48.9%**	**48.4%**	[J]=[H]-[A]/[A]
MISO PRM UCAP	**9.4%**	**15.5%**	**26.3%**	**33.5%**	[K]=[I]-[A]/[A]

Table 11-2: Planning Year 2029-2030 MISO System Planning Reserve Margins

11.3 MISO Planning Reserve Margin Outyear Projections

Tables 11-3, 11-4, 11-5, and 11-6 show the outyear seasonal PRM projections. Years one, four, and six were probabilistically modeled. PRM projections in years two, three, and five are the result of interpolation of the years studied and years seven through ten are the resulting extrapolations of the outyear analyses.

Metric	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
PRM ICAP	17.7%	18.1%	18.5%	18.9%	19.0%	19.0%	19.3%	19.5%	19.8%	20.1%
PRM UCAP	9.0%	9.2%	9.4%	9.6%	9.5%	9.4%	9.4%	9.5%	9.6%	9.7%
Demand (GW)	124.7	125.2	125.7	126.2	126.9	127.5	128.1	128.6	129.2	129.8
ICAP (GW)	150.2	152.8	155.5	158.1	163.0	167.9	171.4	175.0	178.5	182.0

Table 11-3: MISO Summer Planning Reserve Margin Outyear Projections

Metric	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
PRM ICAP	25.2%	25.9%	26.7%	27.5%	27.5%	27.5%	28.0%	28.4%	28.9%	29.4%
PRM UCAP	14.2%	14.8%	15.3%	15.9%	15.7%	15.5%	15.7%	16.0%	16.3%	16.5%
Demand (GW)	112.2	112.7	113.2	113.7	114.3	114.9	115.4	116.0	116.5	117.0
ICAP (GW)	148.8	151.7	154.7	157.7	161.6	165.5	168.8	172.2	175.5	178.9

Table 11-4: MISO Fall Planning Reserve Margin Outyear Projections

Metric	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
PRM ICAP	49.4%	49.2%	49.0%	48.8%	48.9%	48.9%	48.8%	48.7%	48.6%	48.5%
PRM UCAP	27.4%	27.2%	27.0%	26.8%	26.5%	26.3%	26.1%	25.8%	25.6%	25.4%
Demand (GW)	104.3	104.8	105.3	105.7	106.3	106.9	107.4	107.9	108.4	108.9
ICAP (GW)	165.9	167.4	168.9	170.3	174.1	177.8	180.2	182.6	185.0	187.4

Table 11-5: MISO Winter Planning Reserve Margin Outyear Projections

Metric	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
PRM ICAP	40.8%	42.9%	45.0%	47.1%	47.8%	48.4%	49.9%	51.5%	53.0%	54.5%
PRM UCAP	26.7%	28.7%	30.7%	32.8%	33.1%	33.5%	34.8%	36.2%	37.5%	38.9%
Demand (GW)	99.5	99.9	100.4	100.9	101.4	101.9	102.4	102.9	103.4	103.9
ICAP (GW)	152.1	156.2	160.4	164.5	168.8	173.0	177.2	181.4	185.6	189.8

Table 11-6: MISO Spring Planning Reserve Margin Outyear Projections

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-7

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

Filed September 5, 2025

Exhibit 83

MISO 2025-26 LOLE Study Report

Planning Year 2025-2026 Loss of Load Expectation Study Report

The Planning Year 2025-2026 Loss of Load Expectation (LOLE) Study Report details the various inputs, assumptions, and methodologies utilized in both the probabilistic and the power flow analyses to establish the seasonal Planning Reserve Margin (PRM), Local Reliability Requirement (LRR), and Capacity Import/Export Limit (CIL/CEL) values.

Highlights

- Summer, Winter, and Spring Planning Reserve Margin (PRM) decreased from Planning Year 2024-2025, while the Fall PRM increased slightly.

- In the Planning Year 2025-2026 study, significant year-over-year differences in wind and solar Effective Load Carrying Capability (ELCC) were observed for the Fall, Winter, and Spring seasons.

- An enhanced load development process and improved outage rates were the primary factors for the changes in the Planning Year 2025-2026 results. Additionally, shifting risk hours and ongoing changes to the generation fleet impacted this year's results.

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Executive Summary

In preparation for the annual Planning Resource Auction (PRA), MISO conducts an annual Loss of Load Expectation (LOLE) Study to determine Resource Adequacy Requirements for the upcoming Planning Year. These requirements are identified on a seasonal basis for each Local Resource Zone within MISO.

Review processes played an integral role in this study. MISO would like to thank the Loss of Load Expectation Working Group (LOLEWG), the Resource Adequacy Subcommittee (RASC), and the Independent Market Monitor (IMM) for their assistance and input in this year's study.

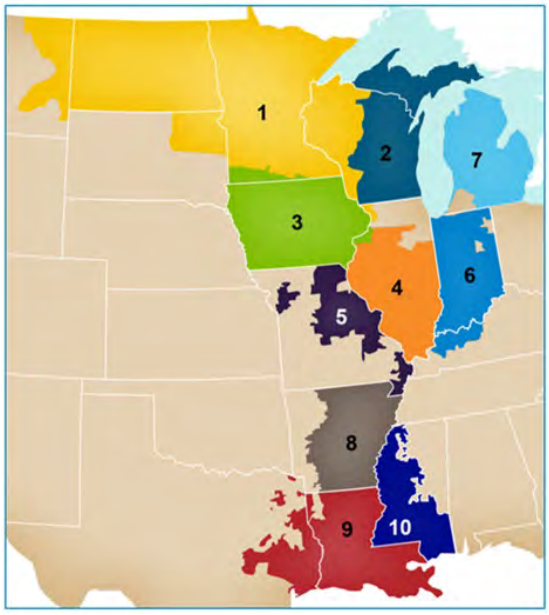
The seasonal Planning Reserve Margin (PRM) values determined through the Planning Year 2025-2026 LOLE study are provided in the table below.

Planning Year 2025-2026 Seasons	Summer 2025	Fall 2025	Winter 2025-2026	Spring 2026
MISO PRM UCAP	7.9%	14.9%	18.4%	25.3%

Table ES-1: Planning Reserve Margin Summary and Comparison

This study also determines zonal Local Reliability Requirements (LRRs). Additionally, initial values for zonal Capacity Import Limits (CIL) and Capacity Export Limits (CEL) for each season are also determined. These quantities are described in greater detail in Section 4.3.

MISO is divided into 10 Local Resource Zones (LRZs) as shown in the figure and table below.



Local Resource Zone	Local Balancing Authorities
1	DPC, GRE, MDU, MP, NSP OTP, SMP
2	ALTE, MGE, MIUP, UPPC, WEC, WPS
3	ALTW, MEC, MPW
4	AMIL, CWLP, GLH, SIPC
5	AMMO, CWLD
6	BREC, CIN, HE, HMPL, IPL, NIPS, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	EMBA, SME

Figure ES-2: Map of MISO Local Resource Zones
Table ES-2: Local Balancing Authority to Local Resource Zone Designations

Tables ES-3 through ES-6 below show results for each season.

PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
LRR UCAP per-unit of LRZ Peak Demand	1.195	1.135	1.318	1.280	1.301	1.262	1.138	1.350	1.136	1.447
Capacity Import Limit (CIL) (MW)	6,025	4,370	5,518	8,649	4,117	8,650	3,579	2,522	4,872	4,474
Capacity Export Limit (CEL) (MW)	3,991	4,614	4,655	4,460	3,939	6,881	5,716	6,345	3,775	2,097

Table ES-3: Initial Planning Resource Auction Deliverables — Summer 2025

PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
LRR UCAP per-unit of LRZ Peak Demand	1.288	1.222	1.537	1.320	1.365	1.312	1.255	1.469	1.198	1.557
Capacity Import Limit (CIL) (MW)	5,690	6,537	7,766	7,908	4,679	8,970	5,125	5,870	5,242	4,508
Capacity Export Limit (CEL) (MW)	6,165	4,259	5,862	4,174	5,816	5,173	5,158	4,024	3,672	3,164

Table ES-4: Initial Planning Resource Auction Deliverables — Fall 2025

PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
LRR UCAP per-unit of LRZ Peak Demand	1.267	1.353	1.632	1.186	1.254	1.247	1.447	1.566	1.297	1.628
Capacity Import Limit (CIL) (MW)	5,575	6,435	5,853	7,353	4,922	7,936	4,762	3,534	4,995	3,458
Capacity Export Limit (CEL) (MW)	3,591	4,793	7,412	4,635	4,814	1,665	5,712	3,681	3,041	2,028

Table ES-5: Initial Planning Resource Auction Deliverables — Winter 2025-2026

PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
LRR UCAP per-unit of LRZ Peak Demand	1.283	1.331	1.588	1.495	1.459	1.388	1.319	1.587	1.292	1.788
Capacity Import Limit (CIL) (MW)	6,398	6,439	7,784	8,272	4,453	9,491	5,166	6,250	5,370	4,365
Capacity Export Limit (CEL) (MW)	5,283	6,119	5,981	4,981	5,797	6,391	5,499	3,559	3,631	3,072

Table ES-6: Initial Planning Resource Auction Deliverables — Spring 2026

1 MISO System Planning Reserve Margin

1.1 LOLE Study Process Overview

In compliance with Module E-1 of the Tariff, MISO performed its annual LOLE study to determine, for each season of Planning Year 2025-2026, the system Planning Reserve Margin Unforced Capacity (PRM UCAP) and the Local Reliability Requirement (LRR) for each Local Resource Zone.

In addition to the LOLE analysis, MISO performed seasonal transfer analyses to determine seasonal Zonal Import Ability (ZIA), Zonal Export Ability (ZEA), Capacity Import Limits (CIL), and Capacity Export Limits (CEL). ZIA and controllable exports are used in conjunction with the Local Reliability Requirement (LRR) values to establish the seasonal Local Clearing Requirement (LCR) values in the Planning Resource Auction (PRA). Seasonal CIL and CEL values determine the maximum amount of capacity that can be imported or exported respectively to or from a zone. These variables are covered in Section 4 of this report.

The PY 2025-2026 per-unit seasonal LRR UCAP multiplied by the updated LRZ seasonal Peak Demand forecasts submitted for the 2025-2026 PRA determines each LRZ's seasonal LRR. Once the seasonal LRR is determined, the ZIA values and controllable exports are subtracted from the seasonal LRR to determine each LRZ's seasonal Local Clearing Requirement (LCR) consistent with Section 68A.6 of Module E-1[1]. An example LCR calculation pursuant to Section 68A.6 of the current effective Module E-1 shows how these values are reached (Table 1-1).

Local Resource Zone (LRZ) EXAMPLE	Example LRZ	Formula Key
Installed Capacity (ICAP)	17,442	[A]
Unforced Capacity (UCAP)	16,326	[B]
Adjustment to UCAP (1d in 10yr)	50	[C]
Local Reliability Requirement (LRR) (UCAP)	16,376	[D]=[B]+[C]
LRZ Peak Demand	14,270	[E]
LRR UCAP per-unit of LRZ Peak Demand	114.8%	[F]=[D]/[E]
Zonal Import Ability (ZIA)	3,469	[G]
Zonal Export Ability (ZEA)	2,317	[H]
Local Clearing Requirement (LCR) EXAMPLE	**Example LRZ**	**Formula Key**
Controllable Exports (UCAP)	150	[J]
Local Reliability Requirement (LRR) (UCAP)	16,376	[K]=[F]*[E]
Local Clearing Requirement (LCR)	12,757	[L]=[K]-[G]-[J]

Table 1-1: Example Local Clearing Requirement Calculation

The actual effective Planning Reserve Margin Requirement (PRMR) for each season of the 2025-2026 Planning Resource Auction will be determined after the updated LRZ Seasonal Peak Demand forecasts are submitted by November 1, 2024. The ZIA, ZEA, CIL, and CEL values are subject to updates in March 2025 based on changes to

[1] https://www.misoenergy.org/legal/tariff
Effective Date: September 1, 2022

exports of MISO resources to non-MISO load, changes to pseudo-tied commitments, and updates to facility ratings following the completion of the LOLE study.

Finally, the Simultaneous Feasibility Test (SFT) is performed as part of the PRA where the deliverability of cleared generation is validated through transfer analysis modeling to ensure transmission reliability. If constraints arise, they are mitigated by adjusting CIL and CEL values as needed.

1.1.1 Study Improvements

The Planning Year 2025-2026 LOLE study incorporated the following improvements:

- **SERVM Improvements:** Enhancements made to SERVM resulted in reliability improvements driven primarily by a more realistic dispatch of demand response resources. In version 9 of SERVM, used for the Planning Year 2025-2026 LOLE analysis, demand response dispatch logic was improved to randomly cycle through demand response resources. This change had a positive impact on reliability because in version 7, used for the Planning Year 2024-2025 LOLE analysis, the dispatch order was fixed and would often happen to have more of the larger demand response units being called first. This in turn caused these larger units to achieve their seasonal run limits more frequently. This new random cycling logic for demand response resources modified the dispatch order for each iteration which allowed smaller demand response units to get called first more often. The overall impact is a modest improvement in reliability because the larger demand response units are not exhausted as often in the simulations as they were in prior models.
- **Improved Load Development Process:** This enhanced process aimed to better account for the correlation between load, weather, and the time of day, and to resolve unrealistic high-risk hours in the early mornings of the Winter season that were identified through concerns expressed by the IMM last year. The PY 2025-2026 load development process also better captured the relationship between higher load and temperature values that establishes a stronger representation of load behavior at more extreme temperatures than the prior load development process. Additional information on this load development process may be found in Section 3.4 of this study report.
- **Expanded consideration of outages driven by extreme cold temperatures**: The accounting of additional forced outages during extreme cold temperatures in the Fall, Winter, and Spring seasons was updated in the PRM and LRR calculations. For context, the LOLE model has historically utilized resource-specific five-year average EFORd values based on historical GADS data, which were updated from annualized EFORd to seasonalized EFORd in the PY 2023-2024 LOLE study. The cold weather outage adder was included in the LOLE model, starting with the PY 2024-2025 LOLE study, to better capture the historic seasonal availability of thermal resources during extreme cold temperatures. This was expanded upon in the PY 2025-2026 LOLE study to include the Fall and Spring seasons.

  Additional thermal forced outages are added to the model during times of extreme cold temperatures to better capture the magnitude of observed correlated outages. The magnitude of additional forced outages increases as temperatures decrease based on the relationship between forced outages and temperature determined from historical GADS and weather data. The modeling of additional forced outages in the Fall, Winter, and Spring seasons due to the adder induces a higher volume of forced outages in the model beyond just the average Fall, Winter, and Spring EFORd. Each LRZ has a unique outage/temperature profile based on actual historical forced outages. The incremental cold weather outages are not assigned to a particular resource but instead represent the aggregate impact on the system for coal, gas, and combined cycle resources.

  The accounting of reduced Unforced Capacity resulting from additional extreme cold weather outages was addressed in the most recent PRM and LRR calculations for the Fall and Spring seasons. A comparative

probabilistic analysis (with and without the cold weather outage adder) quantified the impact of modeling the cold weather outage adder profiles on the system-wide requirements for each season. This impact was distributed pro-rata to the zonal level based on the average magnitude of the zonal cold weather outage adder profiles used in the LRR calculations. The comparative probabilistic analysis resulted in the largest effects for the Winter season (7,265 MW) and minimal effects for the Fall (45 MW) and Spring (1,100 MW) seasons. Summer was not affected by these outages.

1.2 Planning Year 2025-2026 MISO Planning Reserve Margin Results

For Planning Year 2025-2026, the ratio of MISO capacity to forecasted MISO system peak demand yielded a Planning Reserve Margin UCAP of 7.9 percent for the Summer season. Numerous values and calculations went into determining the MISO system PRM ICAP and PRM UCAP (Table 1-2).

MISO Planning Reserve Margin (PRM)	PY 2025-2026 Summer	PY 2025-2026 Fall	PY 2025-2026 Winter	PY 2025-2026 Spring	Formula Key
MISO System Peak Demand (MW)	123,576	108,109	103,910	98,680	[A]
Installed Capacity (ICAP) (MW)	141,908	142,746	147,430	144,513	[B]
Unforced Capacity (UCAP) (MW)	132,389	131,554	126,573	131,289	[C]
Firm External Support ICAP (MW)	1,986	2,315	2,738	2,423	[D]
Firm External Support UCAP (MW)	1,935	2,215	2,594	2,309	[E]
Adjustment to ICAP (MW)	(960)	(9,590)	(6,110)	(10,000)	[F]
Adjustment to UCAP (MW)	(960)	(9,590)	(6,110)	(10,000)	[G]
ICAP PRM Requirement (PRMR) (MW)	142,934	135,472	144,058	136,937	[H] = [B]+[D]+[F]
UCAP PRM Requirement (PRMR) (MW)	133,363	124,179	123,058	123,598	[I] = [C]+[E]+[G]
MISO PRM ICAP	**15.7%**	**25.3%**	**38.6%**	**38.8%**	[J]=[H]-[A]/[A]
MISO PRM UCAP	**7.9%**	**14.9%**	**18.4%**	**25.3%**	[K]=[I]-[A]/[A]

Table 1-2: Planning Year 2025-2026 MISO System Planning Reserve Margins

1.2.1 Additional Risk Metric Statistics

In addition to the LOLE results, SERVM has the ability to calculate several other probabilistic metrics, shown below in Table 1-3. The values for Loss of Load Hours (LOLH) and Expected Unserved Energy (EUE) are calculated at the point where the annual LOLE is at 1 day in 10 years, or 0.1 LOLE for the Summer season, and for the off seasons, values of LOLH and EUE are calculated at the point where the seasonal LOLE is at 1 day in 100 years, or 0.01 LOLE. Loss of Load Hours is the number of hours during a given time period where demand exceeds generation. Like LOLE, LOLH is only measured on the daily peak hour. Expected Unserved Energy is the magnitude of the shortfall when demand exceeds generation and is measured on all hours of simulation.

MISO LOLE Statistics	PY 2025-2026 Summer	PY 2025-2026 Fall	PY 2025-2026 Winter	PY 2025-2026 Spring
Loss of Load Expectation (LOLE) [days/year]	0.100	0.010	0.010	0.010
Loss of Load Hours (LOLH) [hours/year]	0.252	0.015	0.021	0.013
Expected Unserved Energy (EUE) [megawatt-hours/year]	626.161	18.936	24.378	12.807

Table 1-3: PY 2025-2026 Additional Risk Metric Statistics

1.3 Comparison of PRM Targets Across 10 Years

Figure 1-1 compares the PRM UCAP values over the last 10 Planning Years. The last three data points show the Summer PRM UCAP values following FERC's acceptance of MISO's seasonal capacity construct, while the prior data points are indicative of the PRM UCAP under the annual capacity construct.

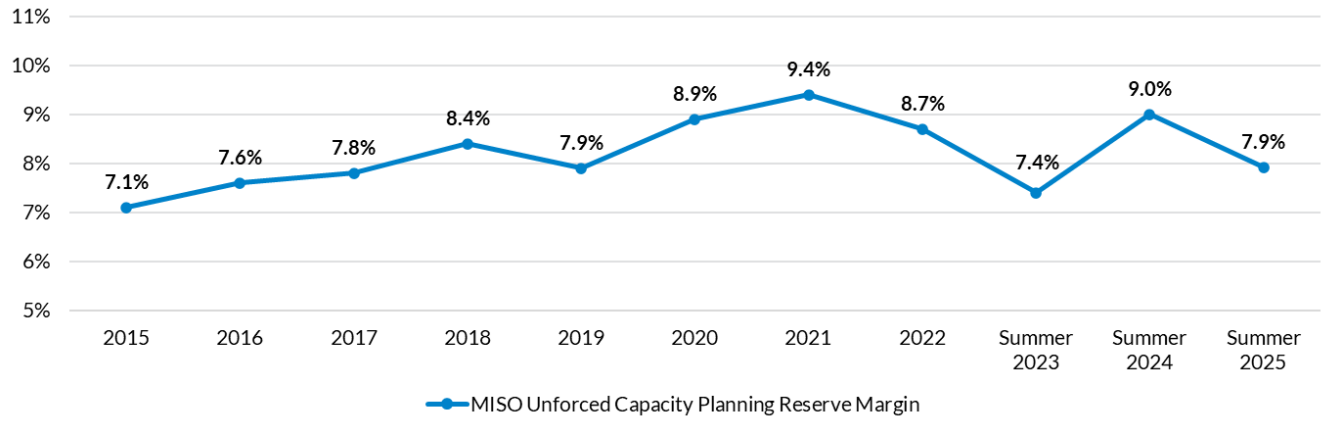


Figure 1-1: Comparison of UCAP PRM Targets Across 10 Years

1.4 Comparison of Planning Year 2024-2025 to Planning Year 2025-2026

Multiple sensitivity analyses were performed to independently quantify the year-over-year changes to the seasonal Planning Reserve Margin (PRM) values driven by various model improvements or model data replacement. The incremental impact to the seasonal PRM values from Planning Year 2024-2025 to Planning Year 2025-2026 due to specific changes to the LOLE model are shown in the waterfall charts below (Figure 1-2, Figure 1-3, Figure 1-4, and Figure 1-5). The following subsections provide more details around each of the sensitivities.

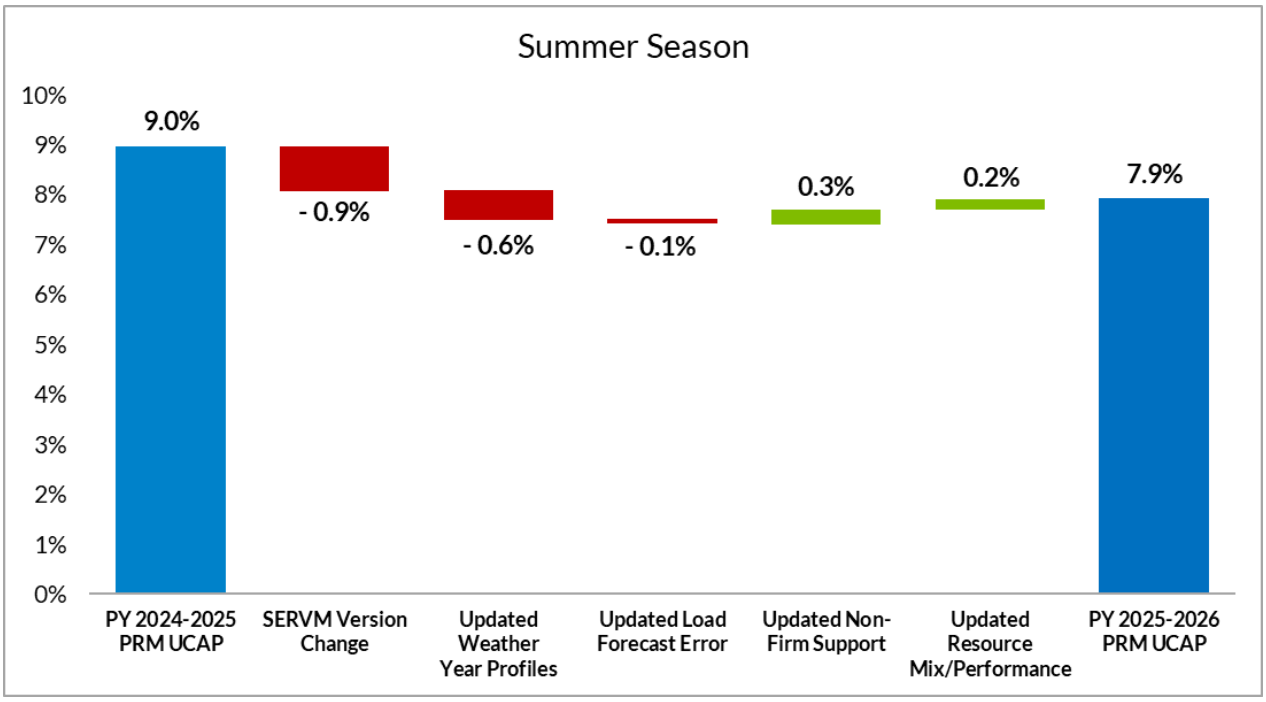


Figure 1-2: Waterfall Chart of Summer PRM UCAP from PY 2024-2025 to PY 2025-2026

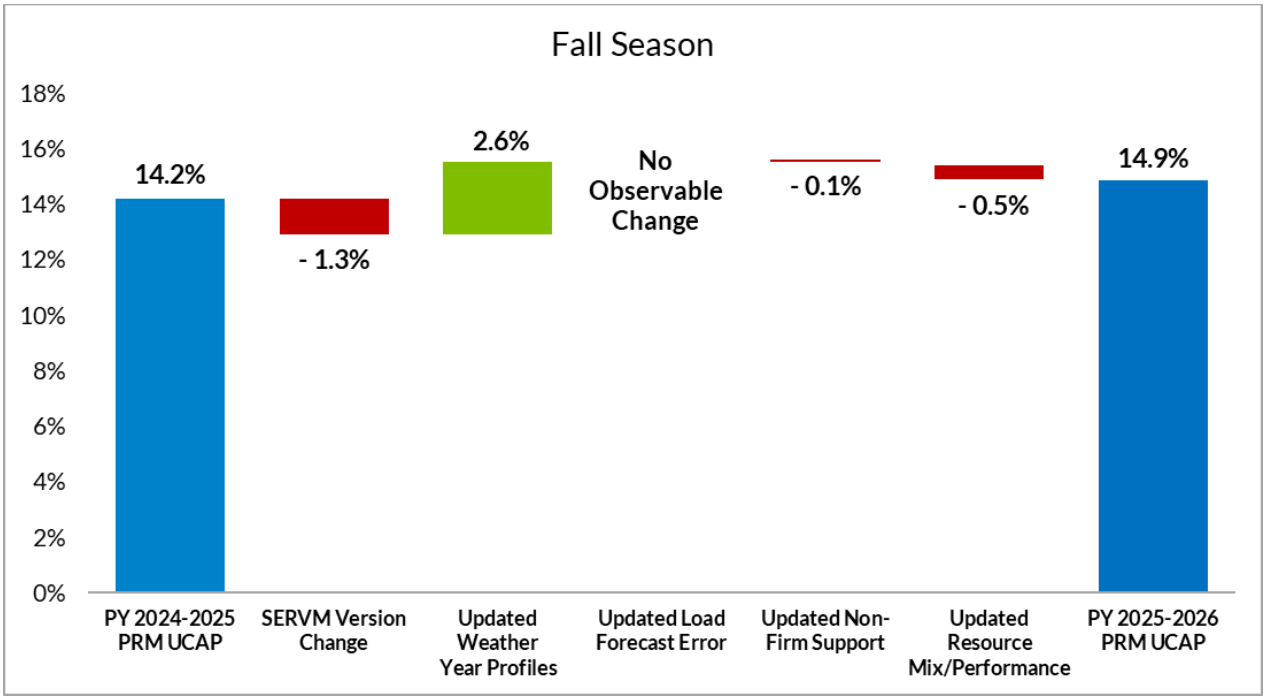


Figure 1-3: Waterfall Chart of Fall PRM UCAP from PY 2024-2025 to PY 2025-2026

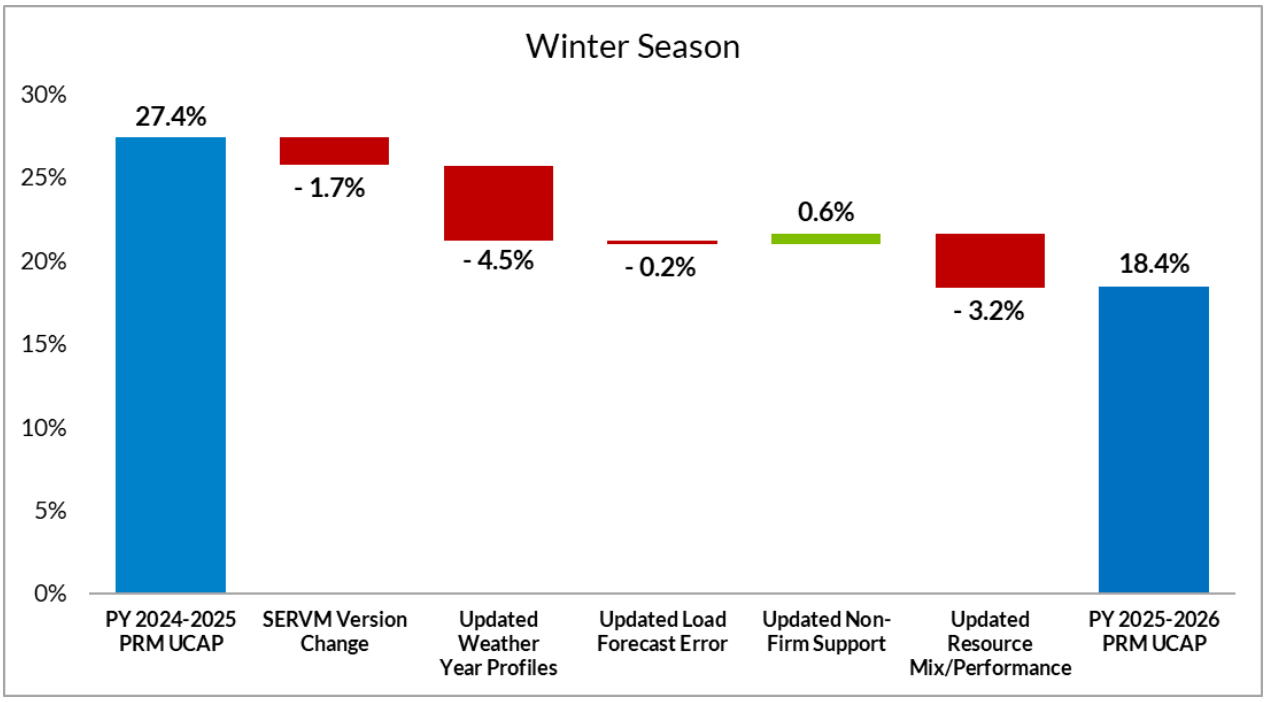


Figure 1-4: Waterfall Chart of Winter PRM UCAP from PY 2024-2025 to PY 2025-2026

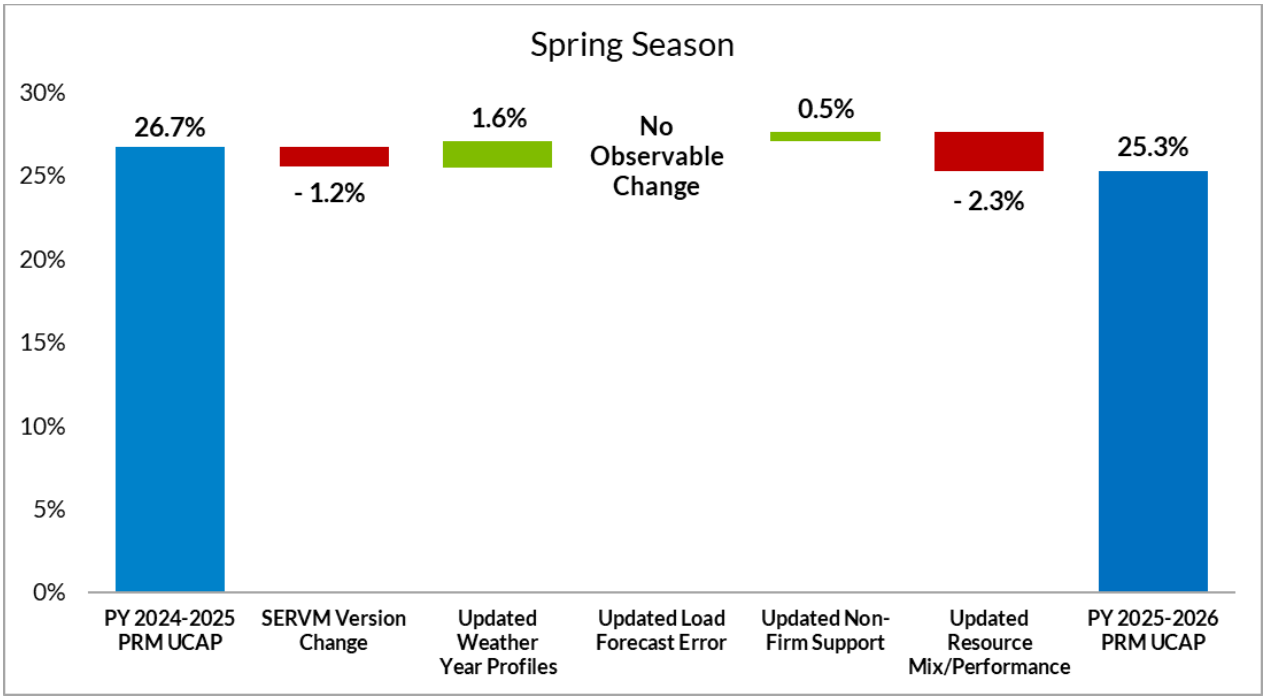


Figure 1-5: Waterfall Chart of Spring PRM UCAP from PY 2024-2025 to PY 2025-2026

1.4.1 Waterfall Chart Details

1.4.1.1 SERVM Improvements

Enhancements made to SERVM for the Planning Year 2025-2026 LOLE study resulted in reliability improvements driven primarily by a more realistic dispatch of demand response and storage resources. Version 9 of SERVM was used in this year's LOLE study.

1.4.1.2 Updated Weather Year Profiles

Every year during the annual refresh of the LOLE model, the oldest weather year is removed and a new weather year is added. In this sensitivity category, MISO analyzes the impacts of all updated hourly profiles that are tied to specific weather years, including profiles for load, wind generation, solar generation, and cold weather outage adders. Since all these variables are tied to specific weather years in the model, it is not possible to isolate the individual impacts of these variables.

1.4.1.3 Updated Non-Firm Support

The probabilistic distribution of seasonal non-firm support is independent of specific weather years and is the next input dataset that is replaced in the year-over-year LOLE model refresh. More information on the modeling of non-firm support can be found in Section 3.5.

1.4.1.4 Updated Resource Mix / Performance

Changes in resource capabilities from Planning Year 2024-2025 are driven by updated seasonal forced outage rates, updated annualized planned maintenance outage rates, new units, retirements, suspensions, replacements, and general changes in the MISO resource fleet.

2 Local Resource Zone Analysis – LRR Results

2.1 Planning Year 2025-2026 Local Resource Zone Analysis

MISO calculated the per-unit LRR of LRZ seasonal peak demand for Planning Year 2025-2026 on a seasonal basis (Table 2-1, Table 2-2, Table 2-3, and Table 2-4). The Unforced Capacity (UCAP) values in the seasonal LRR tables reflect the assumed seasonal UCAP within each LRZ, including Coordinating Owner External Resources and Border External Resources. The adjustments to UCAP values are the megawatt adjustments needed in each LRZ so that the seasonal LOLE criteria are met. LRR is the summation of the zone's total capacity and adjustment to capacity needed to achieve the seasonal LOLE criteria. The LRR is then divided by each LRZ's forecasted seasonal peak demand to determine the per-unit LRR UCAP. The Planning Year 2025-2026 per-unit LRR UCAP values will be multiplied by the updated seasonal peak demand forecasts submitted for the 2025-2026 PRA to determine each LRZ's LRR. The MISO system-wide and zonal peak demand timestamps for all 30 years modeled in the LOLE study are shown in Table 2-5. The peak demand timestamps are subject to the load development process and are not necessarily the actual historical peak days and times.

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2025-2026 Local Reliability Requirements - Summer 2025											
Installed Capacity (ICAP) (MW)	20,621	14,053	11,537	9,290	6,452	17,290	22,708	11,194	22,675	6,086	[A]
Unforced Capacity (UCAP) (MW)	19,636	13,339	11,047	8,726	5,925	15,581	21,136	10,453	21,046	5,501	[B]
Adjustment to UCAP (MW)	1,733	1,067	2,527	2,520	4,318	6,570	2,708	956	3,570	1,975	[C]
Local Reliability Requirement (LRR) UCAP (MW)	21,369	14,406	13,574	11,246	10,243	22,151	23,844	11,408	24,616	7,476	[D]=[B]+[C]
Peak Demand (MW)	17,889	12,694	10,295	8,786	7,873	17,555	20,953	8,448	21,676	5,166	[E]
LRR UCAP per-unit of LRZ Peak Demand	**119.5%**	**113.5%**	**131.8%**	**128.0%**	**130.1%**	**126.2%**	**113.8%**	**135.0%**	**113.6%**	**144.7%**	[F]=[D]/[E]

Table 2-1: Planning Year 2025-2026 LRZ Local Reliability Requirements for Summer 2025

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2025-2026 Local Reliability Requirements - Fall 2025											
Installed Capacity (ICAP) (MW)	20,658	14,203	12,874	9,171	6,442	17,232	22,539	10,910	22,618	6,099	[A]
Unforced Capacity (UCAP) (MW)	19,554	13,196	12,295	8,486	5,883	15,652	20,755	10,184	20,175	5,374	[B]
Adjustment to UCAP (MW)	165	50	1,590	1,565	3,785	5,154	1,937	888	3,449	1,908	[C]
Local Reliability Requirement (LRR) UCAP (MW)	19,719	13,246	13,885	10,051	9,668	20,806	22,692	11,072	23,624	7,282	[D]=[B]+[C]
Peak Demand (MW)	15,313	10,839	9,034	7,616	7,084	15,859	18,085	7,537	19,721	4,676	[E]
LRR UCAP per-unit of LRZ Peak Demand	**128.8%**	**122.2%**	**153.7%**	**132.0%**	**136.5%**	**131.2%**	**125.5%**	**146.9%**	**119.8%**	**155.7%**	[F]=[D]/[E]

Table 2-2: Planning Year 2025-2026 LRZ Local Reliability Requirements for Fall 2025

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2025-2026 Local Reliability Requirements - Winter 2025-2026											
Installed Capacity (ICAP) (MW)	20,600	13,959	12,919	9,288	6,879	17,115	23,377	12,008	24,649	6,635	[A]
Unforced Capacity (UCAP) (MW)	18,563	12,282	11,640	6,065	4,655	13,672	21,359	10,503	22,163	5,671	[B]
Adjustment to UCAP (MW)	995	950	1,950	3,023	4,152	5,950	-840	1,278	3,279	1,617	[C]
Local Reliability Requirement (LRR) UCAP (MW)	19,558	13,232	13,591	9,088	8,806	19,622	20,519	11,781	25,442	7,288	[D]=[B]+[C]
Peak Demand (MW)	15,442	9,781	8,328	7,664	7,023	15,729	14,177	7,524	19,613	4,477	[E]
LRR UCAP per-unit of LRZ Peak Demand	**126.7%**	**135.3%**	**163.2%**	**118.6%**	**125.4%**	**124.7%**	**144.7%**	**156.6%**	**129.7%**	**162.8%**	[F]=[D]/[E]

Table 2-3: Planning Year 2025-2026 LRZ Local Reliability Requirements for Winter 2025-2026

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2025-2026 Local Reliability Requirements - Spring 2026											
Installed Capacity (ICAP) (MW)	19,862	14,049	12,380	9,293	7,423	17,188	22,881	11,694	23,337	6,406	[A]
Unforced Capacity (UCAP) (MW)	18,613	13,073	11,555	7,865	5,961	15,273	20,822	10,613	21,646	5,869	[B]
Adjustment to UCAP (MW)	990	600	1,540	1,910	3,470	4,948	668	199	3,333	1,963	[C]
Local Reliability Requirement (LRR) UCAP (MW)	19,604	13,673	13,094	9,775	9,431	20,221	21,490	10,811	24,979	7,832	[D]=[B]+[C]
Peak Demand (MW)	15,285	10,270	8,246	6,537	6,465	14,570	16,293	6,813	19,333	4,381	[E]
LRR UCAP per-unit of LRZ Peak Demand	**128.3%**	**133.1%**	**158.8%**	**149.5%**	**145.9%**	**138.8%**	**131.9%**	**158.7%**	**129.2%**	**178.8%**	[F]=[D]/[E]

Table 2-4: Planning Year 2025-2026 LRZ Local Reliability Requirements for Spring 2026

Weather Year Time of Peak Demand (EST HE)	MISO	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS
1994	7/6/94 16:00	8/25/94 17:00	8/25/94 16:00	7/19/94 18:00	7/6/94 17:00	1/18/94 15:00	1/19/94 8:00	7/6/94 15:00	1/18/94 21:00	7/3/94 18:00	1/18/94 20:00
1995	7/12/95 17:00	7/13/95 19:00	7/13/95 16:00	7/12/95 16:00	7/12/95 17:00	8/18/95 19:00	7/14/95 19:00	7/14/95 14:00	7/28/95 17:00	7/11/95 18:00	7/28/95 16:00
1996	8/6/96 16:00	7/18/96 16:00	8/14/96 16:00	7/18/96 17:00	7/18/96 18:00	7/18/96 19:00	2/2/96 19:00	8/7/96 16:00	6/30/96 21:00	2/5/96 6:00	7/3/96 16:00
1997	7/14/97 17:00	7/16/97 19:00	7/16/97 17:00	7/25/97 17:00	7/18/97 17:00	7/18/97 19:00	7/14/97 16:00	7/14/97 17:00	7/24/97 17:00	1/17/97 8:00	7/24/97 17:00
1998	7/20/98 16:00	7/14/98 18:00	7/14/98 18:00	7/20/98 19:00	7/21/98 18:00	7/21/98 16:00	7/21/98 17:00	7/21/98 15:00	7/7/98 15:00	8/28/98 18:00	8/27/98 18:00
1999	7/29/99 17:00	7/29/99 17:00	7/30/99 13:00	7/29/99 18:00	7/18/99 18:00	7/29/99 16:00	7/30/99 16:00	7/30/99 16:00	7/29/99 18:00	8/5/99 17:00	8/19/99 17:00
2000	8/31/00 17:00	7/8/00 17:00	7/14/00 16:00	9/2/00 17:00	7/10/00 18:00	8/17/00 18:00	8/9/00 18:00	6/10/00 16:00	7/20/00 14:00	8/26/00 17:00	8/30/00 16:00
2001	7/31/01 17:00	7/31/01 17:00	7/31/01 17:00	7/31/01 16:00	7/23/01 16:00	7/23/01 17:00	8/8/01 17:00	8/8/01 17:00	7/11/01 17:00	8/20/01 16:00	7/11/01 16:00
2002	7/8/02 16:00	7/1/02 19:00	7/18/02 15:00	7/8/02 18:00	7/9/02 17:00	7/23/02 17:00	8/23/02 16:00	7/1/02 16:00	8/6/02 17:00	7/18/02 16:00	7/9/02 17:00
2003	8/26/03 16:00	8/18/03 19:00	8/21/03 16:00	8/25/03 17:00	8/26/03 16:00	8/21/03 16:00	8/27/03 17:00	8/21/03 18:00	8/18/03 15:00	1/24/03 10:00	8/18/03 18:00
2004	7/22/04 16:00	7/21/04 19:00	6/8/04 14:00	7/13/04 18:00	7/22/04 16:00	7/22/04 17:00	12/24/04 10:00	6/9/04 12:00	7/14/04 17:00	8/1/04 16:00	7/31/04 16:00
2005	7/25/05 16:00	7/22/05 18:00	8/10/05 14:00	7/25/05 17:00	7/25/05 18:00	7/25/05 18:00	7/25/05 17:00	6/28/05 16:00	7/22/05 18:00	7/25/05 16:00	7/25/05 18:00
2006	7/31/06 17:00	7/31/06 17:00	7/31/06 18:00	7/19/06 19:00	7/31/06 17:00	8/2/06 18:00	7/31/06 17:00	7/31/06 17:00	7/21/06 15:00	12/8/06 8:00	7/18/06 17:00
2007	8/1/07 17:00	7/26/07 15:00	7/10/07 15:00	7/17/07 18:00	8/28/07 17:00	8/15/07 16:00	8/29/07 17:00	7/31/07 18:00	8/9/07 17:00	8/11/07 18:00	8/14/07 17:00
2008	7/16/08 17:00	7/29/08 18:00	7/17/08 15:00	7/17/08 17:00	7/18/08 17:00	7/18/08 17:00	8/23/08 16:00	8/24/08 12:00	8/2/08 18:00	7/26/08 16:00	7/28/08 17:00
2009	6/24/09 17:00	5/19/09 19:00	6/24/09 17:00	6/22/09 18:00	6/22/09 17:00	6/22/09 17:00	1/16/09 8:00	6/24/09 16:00	6/22/09 16:00	7/2/09 16:00	6/22/09 18:00

Weather Year Time of Peak Demand (EST HE)	MISO	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS
2010	8/10/10 17:00	8/9/10 18:00	7/9/10 17:00	7/14/10 17:00	7/5/10 17:00	8/3/10 16:00	8/10/10 18:00	7/6/10 16:00	8/3/10 17:00	8/2/10 15:00	8/2/10 16:00
2011	7/20/11 17:00	7/18/11 18:00	7/20/11 15:00	8/2/11 17:00	8/24/11 14:00	9/1/11 16:00	9/2/11 18:00	7/21/11 15:00	8/3/11 18:00	8/18/11 16:00	7/13/11 16:00
2012	7/6/12 16:00	7/6/12 18:00	7/4/12 13:00	7/25/12 18:00	7/6/12 16:00	6/28/12 18:00	7/7/12 18:00	7/6/12 14:00	7/28/12 16:00	6/25/12 18:00	7/4/12 16:00
2013	7/19/13 16:00	8/27/13 18:00	7/19/13 14:00	8/30/13 17:00	8/30/13 17:00	8/30/13 16:00	8/30/13 16:00	7/19/13 14:00	8/30/13 17:00	8/5/13 17:00	7/30/13 17:00
2014	7/22/14 17:00	7/21/14 18:00	7/22/14 16:00	7/22/14 17:00	8/22/14 17:00	8/26/14 16:00	8/26/14 16:00	6/17/14 17:00	1/7/14 9:00	1/7/14 9:00	1/28/14 20:00
2015	7/28/15 17:00	7/14/15 18:00	8/3/15 17:00	7/13/15 15:00	7/28/15 18:00	7/28/15 17:00	9/8/15 16:00	7/29/15 16:00	7/29/15 16:00	1/8/15 7:00	7/30/15 15:00
2016	7/20/16 16:00	7/21/16 18:00	8/10/16 14:00	7/20/16 17:00	8/10/16 15:00	7/23/16 16:00	8/10/16 17:00	8/4/16 15:00	7/21/16 15:00	8/31/16 16:00	7/7/16 15:00
2017	7/20/17 16:00	7/6/17 17:00	7/20/17 14:00	7/20/17 16:00	7/20/17 16:00	7/22/17 18:00	9/22/17 15:00	6/12/17 15:00	7/20/17 15:00	7/19/17 16:00	7/20/17 16:00
2018	7/5/18 14:00	6/29/18 15:00	8/15/18 15:00	8/3/18 16:00	8/16/18 16:00	8/6/18 16:00	1/16/18 19:00	7/5/18 14:00	1/2/18 8:00	8/14/18 16:00	1/17/18 9:00
2019	7/19/19 15:00	7/19/19 17:00	7/16/19 16:00	7/19/19 16:00	7/1/19 17:00	9/17/19 16:00	7/2/19 16:00	7/19/19 13:00	8/13/19 14:00	7/7/19 15:00	7/10/19 14:00
2020	7/18/20 16:00	7/8/20 18:00	7/8/20 16:00	8/26/20 15:00	8/26/20 15:00	7/11/20 16:00	8/25/20 15:00	7/3/20 16:00	7/18/20 15:00	7/10/20 16:00	7/18/20 14:00
2021	7/28/21 15:00	7/5/21 17:00	8/20/21 15:00	6/17/21 16:00	7/7/21 15:00	2/14/21 10:00	8/24/21 16:00	7/7/21 13:00	2/16/21 7:00	8/23/21 16:00	8/11/21 15:00
2022	6/21/22 16:00	6/20/22 16:00	6/21/22 16:00	8/2/22 16:00	7/20/22 16:00	7/22/22 16:00	7/5/22 16:00	6/21/22 16:00	7/26/22 15:00	6/23/22 17:00	6/21/22 16:00
2023	8/23/23 17:00	8/23/23 17:00	8/23/23 15:00	8/23/23 16:00	7/5/23 14:00	8/25/23 16:00	8/24/23 17:00	8/23/23 17:00	7/28/23 16:00	8/27/23 15:00	8/24/23 15:00

Table 2-5: Modeled Peak Demand Days/Hours by Local Resource Zone

3 Loss of Load Expectation Analysis

3.1 LOLE Modeling Input Data and Assumptions

MISO uses a program developed and maintained by Astrapé Consulting called Strategic Energy & Risk Valuation Model (SERVM) to calculate LOLE for the applicable Planning Year. SERVM uses a sequential Monte Carlo simulation to model a generation system and to assess the system's reliability, based on any number of interconnected areas. SERVM calculates LOLE for the MISO system and for each LRZ by stepping through the year chronologically and taking into account generation, load, load modifying resources, generator forced outages, generator planned maintenance outages, weather and economic uncertainty, and external support from neighboring regions.

Building the SERVM model is the most time-consuming task of the LOLE study. Several sensitivities are built to determine how specific inputs and variables impact the results. The base case models determine the seasonal MISO Planning Reserve Margin Unforced Capacity (PRM UCAP) and Local Reliability Requirement (LRR) values for each LRZ for future Planning Years one, four, and six.

3.1.1 Resource Inclusion

Planning Year 2025-2026

The Planning Year 2025-2026 LOLE study used converted capacity from the 2024-2025 PRA as a starting point for which resources to include in the study. This ensured that only resources eligible as Planning Resources were included in the LOLE study. For the PY 2025-2026 LOLE study, internal MISO CPNode resources that were excluded from the auction clearing process but were used to satisfy Resource Adequacy Requirements through a Fixed Resource Adequacy Plan (FRAP) or that offered and subsequently cleared the 2024-2025 PRA in any season were included in the LOLE model for all seasons. Resources that were on an approved Attachment Y suspension or retirement, or had an approved IMM exemption, were excluded from the LOLE model in their respective seasons. External resources were included for only the corresponding seasons in which they were included in a FRAP or offered in the 2024-2025 PRA.

Upcoming changes for Planning Year 2026-2027

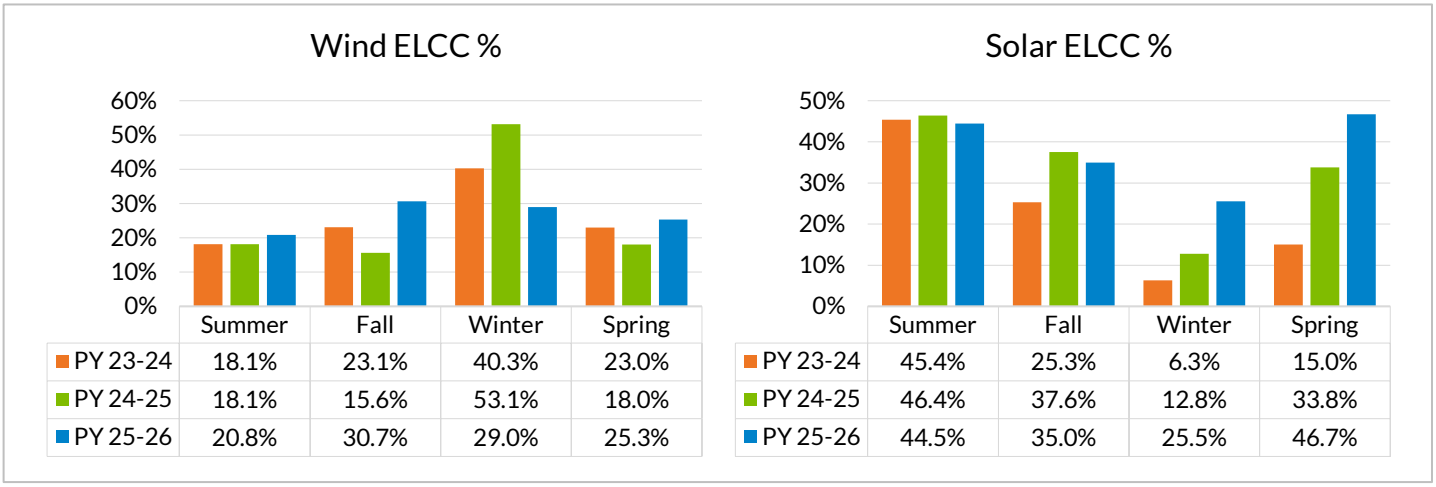
In July 2024, MISO opened a formal feedback request with stakeholders to better define a set of criteria for resource inclusion within the LOLE model that would be implemented for the PY 2026-2027 LOLE study and beyond. From the feedback, it was determined that MISO will include resources for each season a resource is included in a FRAP or offered into the most recent PRA, with an exception for external resources. External resources will be included in the LOLE model for each season that an external resource is included in a FRAP or cleared in the most recent PRA. The rationale is that external resource offer behavior can differ from one year to the next, as they are not subject to economic withholding in MISO and do not have any obligation to serve MISO load if they do not make a commitment to do so through the PRA.

3.1.2 Effective Load Carrying Capability (ELCC)

Each year, MISO performs seasonal Effective Load Carrying Capability (ELCC) analyses for wind and solar resources to quantify their average capacity contribution to determine season-wide capacity values for use in the seasonal Planning Reserve Margin (PRM) and Local Reliability Requirement (LRR) calculations. Wind and solar generation is represented in the model with 30-year hourly capacity factor profiles.

Seasonal wind ELCC determines the allocable Seasonal Accredited Capacity (SAC) for in-service CPNode wind resources for the prompt year PRA. Solar ELCC is not used for accreditation and is only used for calculating solar UCAP in the PRM and LRR equations. More details regarding wind and solar accreditation will be provided in the Planning Year 2025-2026 Wind and Solar Capacity Credit Report.

The Figure 3-1 below details the resulting LOLE study ELCC percentages over the last three Planning Years.



	Summer	Fall	Winter	Spring
PY 23-24	18.1%	23.1%	40.3%	23.0%
PY 24-25	18.1%	15.6%	53.1%	18.0%
PY 25-26	20.8%	30.7%	29.0%	25.3%

	Summer	Fall	Winter	Spring
PY 23-24	45.4%	25.3%	6.3%	15.0%
PY 24-25	46.4%	37.6%	12.8%	33.8%
PY 25-26	44.5%	35.0%	25.5%	46.7%

Figure 3-1: Planning Year 2025-2026 Wind and Solar ELCC Trends

Over the past several years, variability in the non-Summer season results have been observed for both wind and for solar. This is largely driven by the evolving resource mix within the MISO system and the resulting hours of risk for each year's model. Additionally, due to the Summer season having a higher LOLE criterion of 0.1 LOLE (or 1 day of loss of load in 10 years) at the system-wide level, there is a greater volume of impacted Loss of Load Hours (LOLH) in the Summer compared to the other seasons. This results in a larger sampling of wind and solar generation used in the ELCC analyses for Summer than in the other seasons.

Seasonal Drivers of Change from Planning Year 2024-2025 to Planning Year 2025-2026 are detailed below:

- **Summer**: The majority of the risk in the Planning Year 2024-2025 Summer season was observed in July. However, in Planning Year 2025-2026, there was an increase in prolonged risk observed in August. This resulted in wind generation impacting more hours during the Summer season and solar impacting slightly less as LOLH extended further into evening hours.
- **Fall**: In Planning Year 2024-2025, September was the only month that exhibited risk for the MISO system in the Fall season. In Planning Year 2025-2026, September risk increased and November demonstrated some morning and evening risk hours. Due to the shift in Fall risk hours, the number of hours where wind generation was able to be impactful increased, while the number of hours where solar could be impactful decreased.
- **Winter**: Changes in ELCC values for the Winter season were primarily driven by Planning Year 2025-2026 load development process enhancements. These enhancements shifted risk hours to later in the day where wind performed worse and solar was able to perform better during the full set of risk hours.
- **Spring**: During this season, MISO saw an increase in both wind and solar ELCC values. In Planning Year 2025-2026, Spring risk materialized during several evening hours in March, and the overall magnitude of risk increased in comparison with Planning Year 2024-2025. This allowed both wind and solar generation to become more impactful during hours of greater renewable output.

3.2 MISO Generation

3.2.1 Thermal Units

All MISO internal thermal Planning Resources were modeled in the LRZ in which they are physically located, except for pseudo-tied resources. Additionally, Coordinating Owner External Resources and Border External Resources were modeled as being internal to the LRZ in which they are committed to serving load.

Seasonal forced outage rates and annualized planned maintenance outage rates were calculated over a five-year period (January 2019 to December 2023) for each resource. Some resources did not have five years of historical data in MISO's Generator Availability Data System (PowerGADS). However, if they had at least three consecutive months of outage data, resource-specific information was used to calculate their seasonal forced and planned maintenance outage rates. Resources with fewer than three consecutive months of resource-specific outage data were assigned the corresponding MISO seasonal class average forced outage rate and annualized planned maintenance outage rate based on their resource type. The overall MISO ICAP-weighted seasonal class average forced outage rates and annualized planned maintenance outage rate were applied in lieu of class averages for classes with fewer than 30 resources reporting 12 or more months of data.

The historical class average outage rates as well as the MISO system-wide weighted average forced outage rate are provided in Table 3-1 to show the year-over-year trends, as well as in Table 3-2 on a seasonal basis for the prompt Planning Year.

Pooled EFORd GADS Years	**2019-2023 (%)**	**2018-2022 (%)**	**2017-2021 (%)**	**2016-2020 (%)**	**2015-2019 (%)**	**2014-2018 (%)**
LOLE Study Planning Year	**PY 2025-2026** Summer	**PY 2024-2025** Summer	**PY 2023-2024** Summer	**PY 2022-2023** Annualized	**PY 2021-2022** Annualized	**PY 2020-2021** Annualized
Combined Cycle	5.26	5.92	5.54	5.85	5.52	5.70
Combustion Turbine (0-50 MW)	10.80	7.65	7.37	15.25	15.83	17.88
Combustion Turbine (50+ MW)	4.72	4.88	4.07	4.36	4.76	4.65
Diesel Engines	17.52	17.14	12.79	7.25	10.05	23.53
Fluidized Bed Combustion	*	*	*	*	*	*
Hydro (0-30 MW)	*	*	*	*	*	*
Hydro (30+ MW)	*	*	*	*	*	*
Nuclear	*	*	*	*	*	*
Pumped Storage	*	*	*	*	*	*
Steam – Coal (0-400 MW)	11.76	8.22	7.03	9.91	8.78	8.15
Steam - Coal (400-1,000 MW)	8.84	8.62	8.06	9.00	9.02	8.87
Steam - Gas	11.32	14.04	12.48	11.84	12.91	12.54
Steam - Oil	*	*	*	*	*	*
Steam - Waste Heat	*	*	*	*	*	*
Steam - Wood	*	*	*	*	*	*
MISO Weighted System-wide	7.76	8.24	8.23	9.04	9.36	9.24

Table 3-1: Historical Class Average Forced Outage Rates

Pooled EFORd GADS Years	2019-2023 (%)	2019-2023 (%)	2019-2023 (%)	2019-2023 (%)
LOLE Study Planning Year 2025-2026	**Summer 2025**	**Fall 2025**	**Winter 2025-2026**	**Spring 2026**
Combined Cycle	5.26	6.95	5.16	5.93
Combustion Turbine (0-50 MW)	10.80	13.42	33.67	15.79
Combustion Turbine (50+ MW)	4.72	7.96	12.50	5.31
Diesel Engines	17.52	31.84	24.53	23.91
Fluidized Bed Combustion	*	*	*	*
Hydro (0-30 MW)	*	*	*	*
Hydro (30+ MW)	*	*	*	*
Nuclear	*	*	*	*
Pumped Storage	*	*	*	*
Steam – Coal (0-400 MW)	11.76	15.27	12.68	11.17
Steam - Coal (400-1,000 MW)	8.84	9.20	9.83	9.94
Steam - Gas	11.32	12.91	9.83	9.32
Steam - Oil	*	*	*	*
Steam - Waste Heat	*	*	*	*
Steam - Wood	*	*	*	*
MISO Weighted System-wide	7.76	8.93	10.48	9.70

Table 3-2: Planning Year 2025-2026 Seasonal Class Average Forced Outage Rates

3.2.2 Behind-the-Meter Generation

Behind-the-Meter Generation data came from the Module E Capacity Tracking (MECT) tool. Behind-the-Meter Generation backed by thermal resources were explicitly modeled as any other thermal generator with a monthly capability and forced outage rate. Behind-the-Meter Generation backed by intermittent resources were modeled at their expected seasonal availability.

3.2.3 Attachment Y

MISO obtained information on generating resources with approved suspensions or retirements (as of June 1, 2024) through MISO's Attachment Y process. Any resource with an approved retirement or suspension in Planning Year 2025-2026 was excluded from the year-one analysis during the months in which the resource had been approved to be out of service. This same methodology is used for the four- and six-year analyses.

3.2.4 Future Generation

The LOLE model included resources with a signed and executed Generator Interconnection Agreement (as of June 1, 2024). These future resources were assigned seasonal class average forced outage rates and planned maintenance outage rates based on their resource class. Future thermal generation and upgrades were added to the LOLE model based on resource information in the MISO Generator Interconnection Queue. Resources with a planned upgrade during the study period reflect the megawatt increase for each month, beginning the month the upgrade is expected to be completed. The LOLE analysis includes future wind and solar generation, tied to the same hourly wind and solar profiles used for existing wind and solar resources in the model. In the LOLE model, resources with a signed and

executed GIA receive a postponement to their anticipated in-service dates relative to the average delays per resource type observed by the Generation Interconnection team at MISO.

3.2.5 Intermittent Resources

Intermittent resources include solar, wind, biomass, battery storage, and run-of-river hydro. Most intermittent resources submit historical output data during seasonal peak hours, defined as hours ending 15, 16, and 17 EST for Summer, Fall, and Spring, and hours ending 8, 9, 19, and 20 for Winter. Non-CPNode wind and battery storage resources are exceptions to this and only submit historical output data for the top eight seasonal coincident peaks for the last three Planning Years for which data is available. This data is averaged at the seasonal level and modeled in the LOLE analysis as seasonal effective capacity for all months within a given season. Each individual resource is modeled in the LRZ corresponding to its load obligation.

Using historical wind operational data from 279 front-of-meter wind resources from 2013 to 2023, normalized hourly capacity profiles were developed and aggregated at the LRZ level to represent hourly wind capability in the model. As a result of the LOLE analysis that is based on 30 weather years (1994 – 2023), synthetic shapes were developed by Astrapé for the 1994 – 2013 period based on historical wind performance and temperatures. Once the weather and wind performance matching has been performed, the data is analyzed as a function of load to ensure the variability around the load profiles is reasonable.

Solar profiles were also developed by Astrapé using historical solar irradiance data from the NREL National Solar Radiation Database (NSRDB) from 1998 – 2023.

3.2.6 Demand Response

Demand response programs and their capabilities came from their corresponding registrations in the MECT tool. These resources were explicitly modeled as dispatch-limited resources and are the last set of resources dispatched by the model in an effort to avoid LOLE. Each demand response program was modeled individually with a monthly capability, limited by duration and the number of times each program can be called upon for each season.

3.3 MISO Capacity

The following charts and tables below list the total Installed Capacity (ICAP) values by resource type and LRZ in the PY 2025-2026 LOLE model. Every July, MISO presents the preliminary capacity in the prompt year LOLE model at the LOLEWG and, starting with PY 2025-2026, MISO published the final ICAP values per zone and per season in its LOLE study report.

PY 2025-2026 ICAP MW, Summer											
Resource Type	**LRZ1**	**LRZ2**	**LRZ3**	**LRZ4**	**LRZ5**	**LRZ6**	**LRZ7**	**LRZ8**	**LRZ9**	**LRZ10**	**MISO**
Thermal	15,467	11,882	7,659	7,532	5,946	14,049	19,291	9,831	21,917	5,743	119,315
Demand Response	1,879	693	504	435	184	1,695	1,294	790	335	45	7,852
BTMG	1,460	339	603	310	97	351	1,073	17	20	104	4,373
Battery Storage	0	0	0	0	0	101	0	0	0	0	101
Wind	7,285	893	12,782	1,897	406	1,281	3,606	0	0	185	28,335
Solar	212	1,891	224	1,390	0	1,393	639	1,108	392	351	7,599
Run-of-River/Biomass	205	113	10	0	142	208	15	64	229	0	986
Total	**26,507**	**15,810**	**21,782**	**11,564**	**6,774**	**19,078**	**25,917**	**11,810**	**22,892**	**6,427**	**168,561**

Table 3-3: Summer Total Installed Capacity by Resource Type and Local Resource Zone

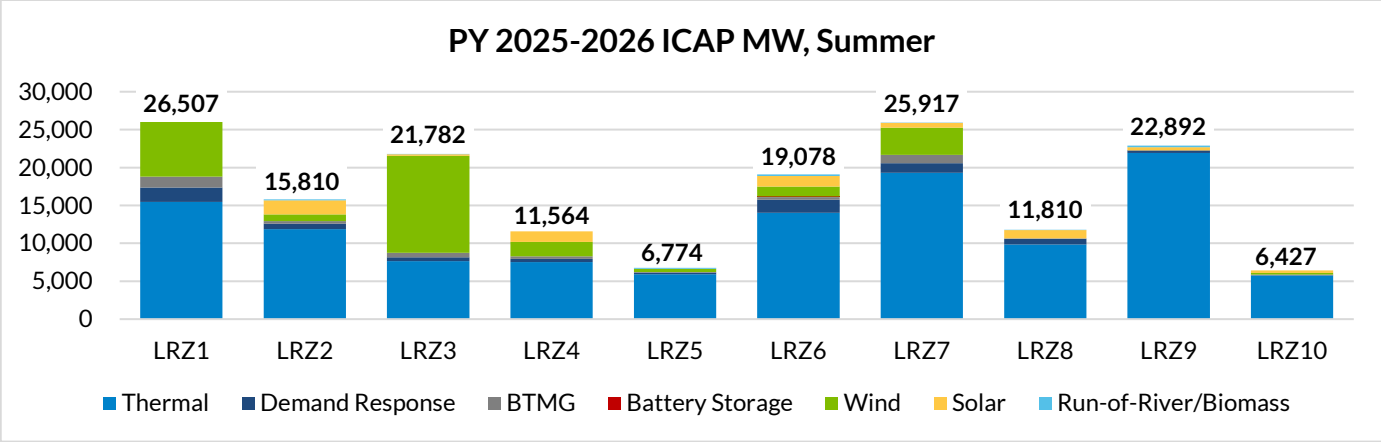


Figure 3-2: Summer Total Installed Capacity by Resource Type and Local Resource Zone

PY 2025-2026 ICAP MW, Fall											
Resource Type	**LRZ1**	**LRZ2**	**LRZ3**	**LRZ4**	**LRZ5**	**LRZ6**	**LRZ7**	**LRZ8**	**LRZ9**	**LRZ10**	**MISO**
Thermal	15,477	12,095	7,765	7,357	6,043	14,203	19,506	9,884	22,001	5,812	120,142
Demand Response	1,435	719	512	440	47	1,515	627	586	334	5	6,220
BTMG	1,235	337	591	305	96	344	1,061	13	19	103	4,103
Battery Storage	0	0	0	0	0	101	0	0	0	0	101
Wind	7,285	893	12,782	1,897	406	1,281	3,606	0	0	185	28,335
Solar	212	1,891	224	1,390	0	1,393	639	1,108	392	351	7,599
Run-of-River/Biomass	201	117	5	0	133	189	16	39	127	0	828
Total	**25,846**	**16,052**	**21,879**	**11,389**	**6,723**	**19,025**	**25,454**	**11,630**	**22,873**	**6,456**	**167,328**

Table 3-4: Fall Total Installed Capacity by Resource Type and Local Resource Zone

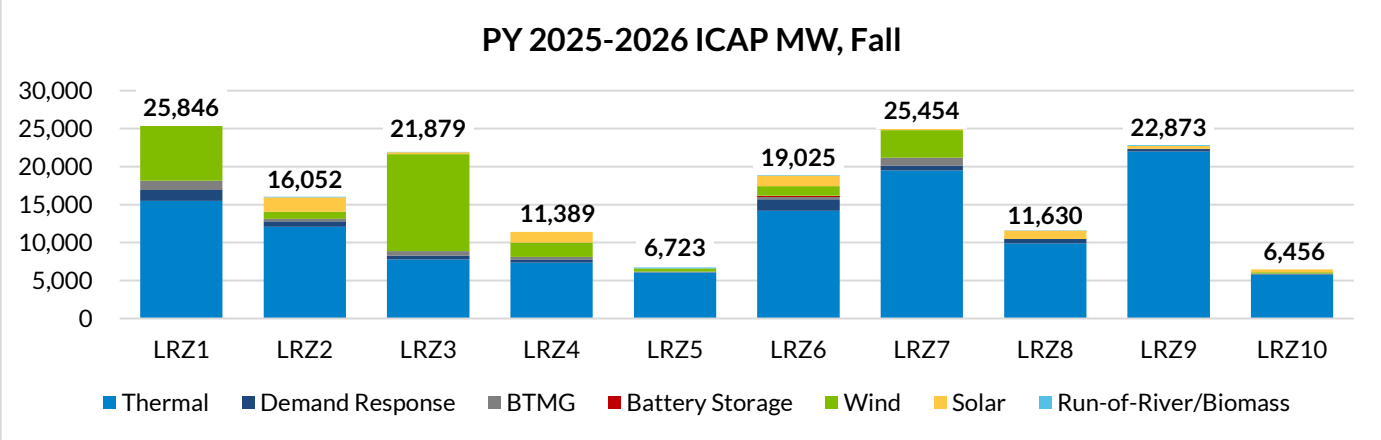


Figure 3-3: Fall Total Installed Capacity by Resource Type and Local Resource Zone

PY 2025-2026 ICAP MW, Winter											
Resource Type	**LRZ1**	**LRZ2**	**LRZ3**	**LRZ4**	**LRZ5**	**LRZ6**	**LRZ7**	**LRZ8**	**LRZ9**	**LRZ10**	**MISO**
Thermal	15,955	12,056	8,142	7,739	6,504	14,392	20,471	10,561	23,999	6,384	126,202
Demand Response	1,560	701	391	325	33	1,407	660	1,088	334	5	6,504
BTMG	756	343	616	318	92	334	1,020	17	10	103	3,609
Battery Storage	0	0	0	0	0	101	0	0	0	0	101
Wind	7,285	893	12,782	1,897	406	1,281	3,606	0	0	185	28,335
Solar	212	1,891	224	1,390	0	1,393	639	1,108	392	351	7,599
Run-of-River/Biomass	162	118	5	0	133	154	18	59	206	0	853
Total	**25,930**	**16,001**	**22,160**	**11,669**	**7,168**	**19,062**	**26,413**	**12,833**	**24,941**	**7,028**	**173,204**

Table 3-5: Winter Total Installed Capacity by Resource Type and Local Resource Zone

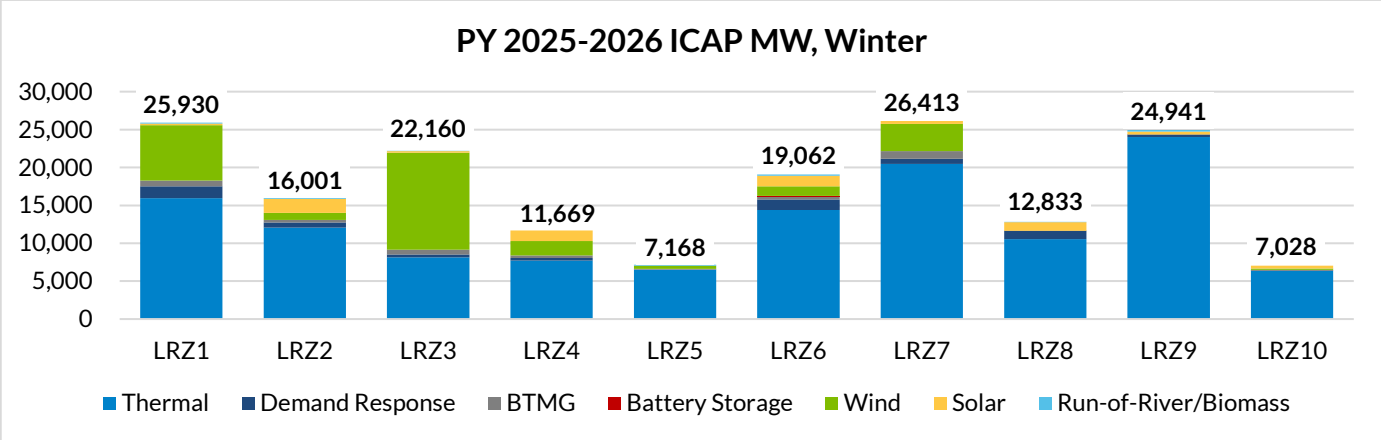


Figure 3-4: Winter Total Installed Capacity by Resource Type and Local Resource Zone

PY 2025-2026 ICAP MW, Spring											
Resource Type	**LRZ1**	**LRZ2**	**LRZ3**	**LRZ4**	**LRZ5**	**LRZ6**	**LRZ7**	**LRZ8**	**LRZ9**	**LRZ10**	**MISO**
Thermal	14,895	11,695	7,928	7,470	6,960	13,910	19,783	10,072	22,307	5,959	120,980
Demand Response	1,404	719	387	386	57	1,522	670	887	334	5	6,370
BTMG	1,390	388	619	309	95	352	1,127	27	23	104	4,433
Battery Storage	0	0	50	0	0	301	0	0	25	0	376
Wind	7,285	893	12,982	1,897	406	1,281	3,606	0	0	185	28,535
Solar	212	1,891	224	1,390	180	1,393	788	1,383	867	626	8,953
Run-of-River/Biomass	229	138	4	0	124	129	20	62	243	0	949
Total	**25,415**	**15,724**	**22,195**	**11,451**	**7,822**	**18,888**	**25,994**	**12,432**	**23,799**	**6,878**	**170,596**

Table 3-6: Spring Total Installed Capacity by Resource Type and Local Resource Zone

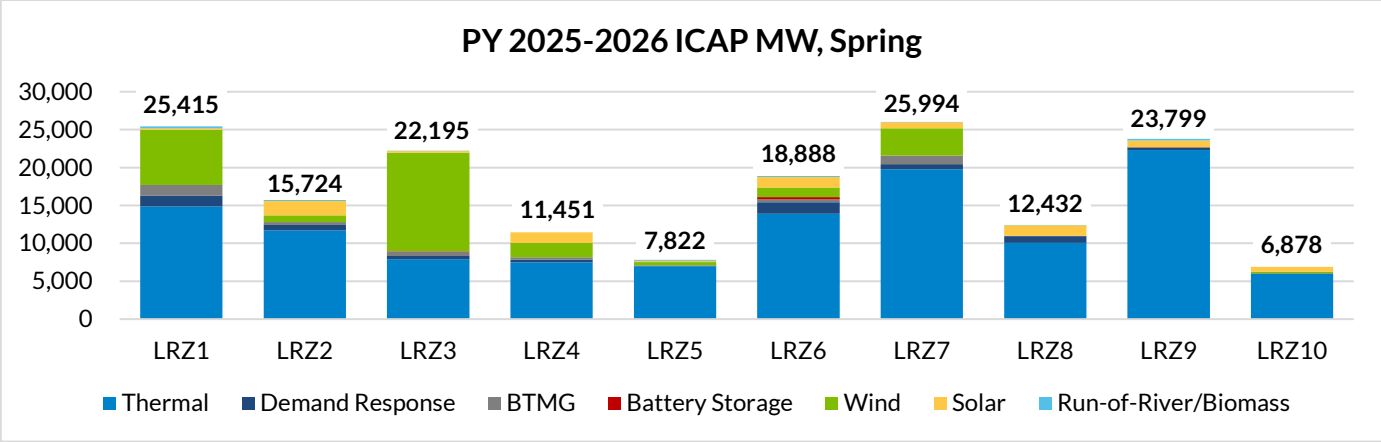


Figure 3-5: Spring Total Installed Capacity by Resource Type and Local Resource Zone

3.4 MISO Load Data

Every year, the Load Serving Entities submit new load forecasts to MISO by November 1 and, every year, MISO utilizes these load forecasts in the load development process for the LOLE study to align the load in the model with the anticipated load growth forecasted within each Local Resource Zone. At the request of stakeholders, MISO expanded its load data section to provide additional information about the LOLE study load development process.

The load development process for the Planning Year 2025-2026 LOLE analysis was enhanced through a peak correcting step regression. The regression was broadened to better account for correlations between the time of day, temperature, and load. While in the prior Planning Year 2024-2025, peak regressions factored in correlations between temperature and load without much consideration to the time of day. The Planning Year 2025-2026 LOLE analysis used a load training process pared with neural net software to establish a correlated relationship between the most recent five years of historical weather and load data. This relationship was then applied to 30 years of hourly historical load data to create 30 years of load shapes for each LRZ to capture both load diversity and seasonal variability. Zonal Coincident Peak Forecasts provided by the Load Serving Entities were used to develop zonal- and monthly-specific load forecast scaling factors which scale the average of the 30-year load shapes based on provided forecasts. The results of this process are shown as the MISO System Peak Demand (Table 1-2) and zonal Peak Demand (Table 2-1, Table 2-2, Table 2-3, and Table 2-4).

Direct Control Load Management and Interruptible Demand types of demand response were included in the LOLE model as resources. Demand response is dispatched in the LOLE model to avoid load shed during simulation when all other available generation has been exhausted.

The load development process is composed of several steps outlined in this section and will continue to be refined as needed in order to better capture weather uncertainty associated with the most recent load forecasts submitted by the Load Serving Entities.

The first step of the load development process includes data collection of the most recent year of historical hourly load data and the most recent historical temperature data from a zonal-specific weather station. This data is then consolidated with prior load and temperature data for a total historical dataset comprised of 30 years of hourly weather data and five years of hourly load data. For the PY 2025-2026 LOLE study, five years of historical data (2019 - 2023) was used in the neural net training/prediction portion of the load development process.

Data Sources:

- Historical load data is collected from MISO Resource Assessment in compliance with NERC standard MOD-032-2 requirements.
- Weather data is collected through the National Oceanic and Atmospheric Administration (NOAA) and collected from the following weather stations for each zone.

LRZ	Station	Name	State	Latitude	Longitude	Elevation
1	72658014922	MINNEAPOLIS ST. PAUL INTERNATIONAL AIRPORT, MN US	Minnesota	44.89	-93.23	254.5
2	72640014839	MILWAUKEE MITCHELL AIRPORT, WI US	Wisconsin	42.95	-87.90	203.3
3	72546014933	DES MOINES INTERNATIONAL AIRPORT, IA US	Iowa	41.53	-93.65	286.3
4	72439093822	SPRINGFIELD ABRAHAM LINCOLN CAPITAL AIRPORT, IL US	Illinois	39.85	-89.68	176.7
5	72434013994	ST LOUIS LAMBERT INTERNATIONAL AIRPORT, MO US	Missouri	38.75	-90.37	162
6	72438093819	INDIANAPOLIS INTERNATIONAL AIRPORT, IN US	Indiana	39.73	-86.28	241.3
7	72539014836	LANSING CAPITAL CITY AIRPORT, MI US	Michigan	42.78	-84.60	261.2
8	72340313963	LITTLE ROCK AIRPORT ADAMS FIELD, AR US	Arkansas	34.73	-92.24	76.4
9	72231012916	NEW ORLEANS AIRPORT, LA US	Louisiana	30.00	-90.28	-1
10	72235003940	JACKSON INTERNATIONAL AIRPORT, MS US	Mississippi	32.32	-90.08	90.2

Table 3-7: Local Resource Zone Weather Stations

The second step of the process is to normalize the five years of load data to consistent economics. Each zone is analyzed and isolated to remove economic impacts on load to ensure that load levels at different temperatures provide an appropriate range across the most recent five years of historical data. This process involves zonal load growth adjustments by comparing the most recent five years of historical load at extreme temperatures and shifting the shapes up or down if they do not reasonably overlay on top of each other. A regression analysis is then performed at the zonal level, focusing on Summer, Winter, and off-peak periods in order to compensate for the fact that the neural net training software can occasionally over- or under-predict results for extremely high or extremely low temperatures.

The third step of the process utilizes neural net software to establish functional relationships between the most recent five years of historical weather and load data. The NeuroShell Predictor software performs neural net training and predicting using a genetic algorithm. Since temperature data is not a direct input into the SERVM model, the relationships and effects it has on the MISO system are included in the 30-year hourly load shapes.

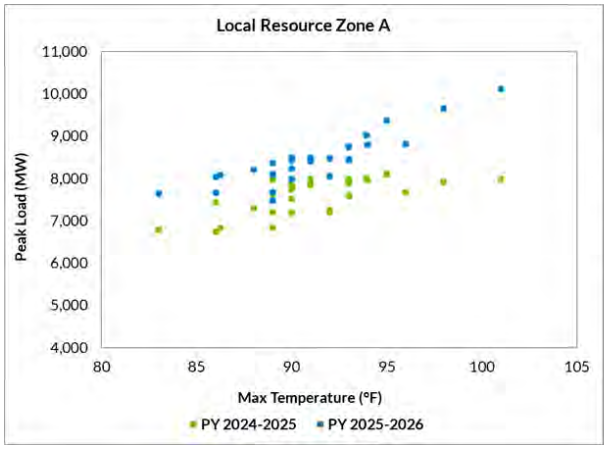
During the temperature and load training portion of this process, MISO evaluated each of the 10 LRZs by the following seasonal groupings: Summer, Winter, and off-season. Starting in the PY 2025-2026 LOLE study, the off-season grouping included both the Fall and Spring seasons. This was done to ensure there were enough extreme temperature data points and account for a larger sampling of temperature and load variability when the neural net predicts future load uncertainty. This process change resulted in an improved correlation between historical temperature and load data for the Fall and Spring seasons. The peak load and intra-hour load predictions drove some general load increases in these seasons during periods of extreme temperatures.

The graphs in Figure 3-6 below show how load responds to higher observed temperatures for months within the Fall and Spring seasons.

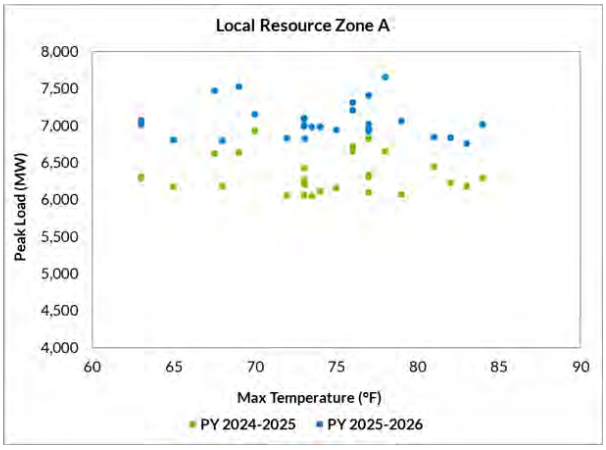
Comparable to off-season periods, the neural net software established functional relationships between historical temperature and load for the Summer and Winter seasons. However, unlike the off-season periods, the correlations between temperature and load for Summer and Winter seasons remained stable in the PY 2025-2026 LOLE study. When comparing the current Planning Year to the prior, no major outliers or concerns were identified in these correlations, and both years showed a general trend of increases in load at extreme temperatures.

The graphs in Figure 3-7 below show how load responds to higher observed temperatures for months within the Summer and Winter seasons.

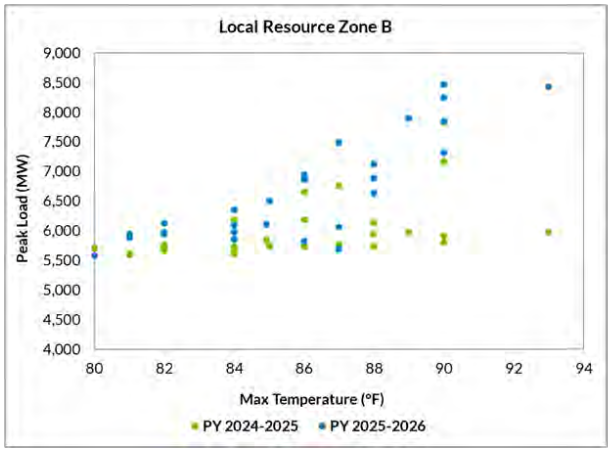
Fall Season
Temperature and Load Correlation
September



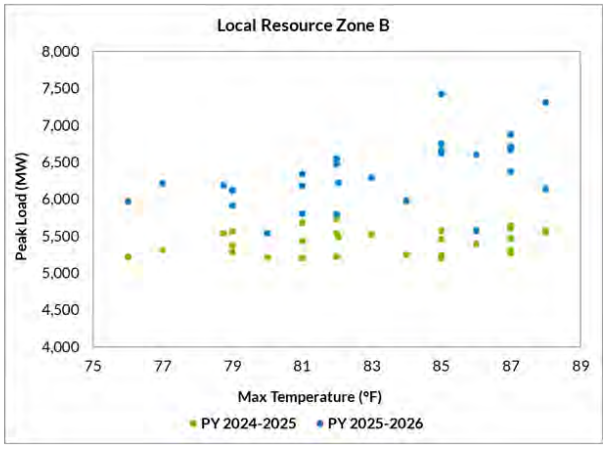
Spring Season
Temperature and Load Correlation
March



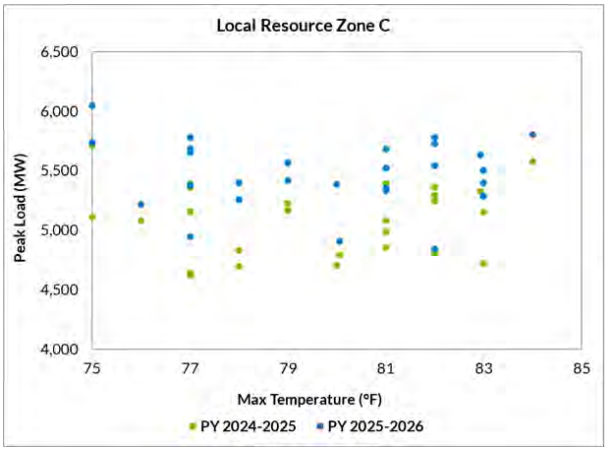
October



April



November



May

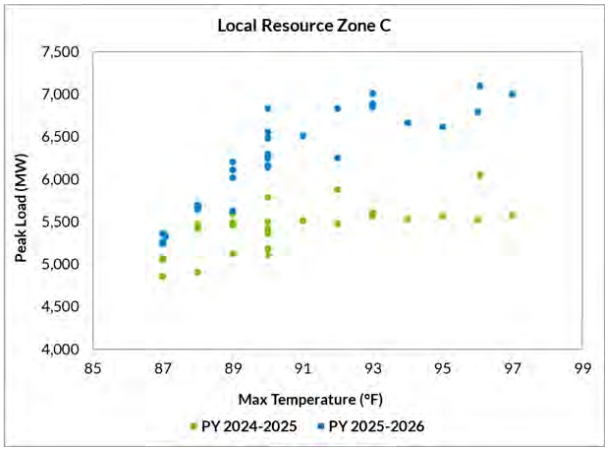
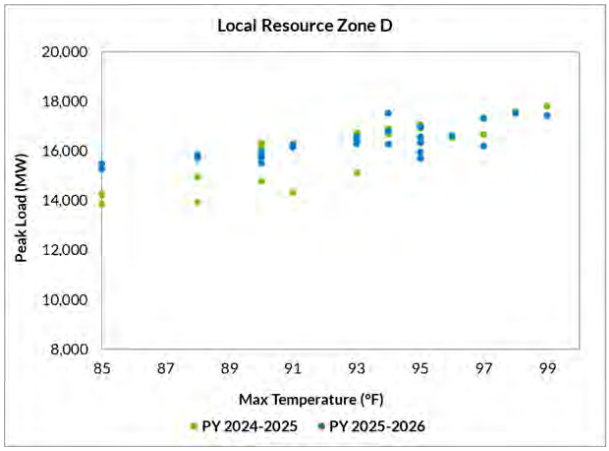
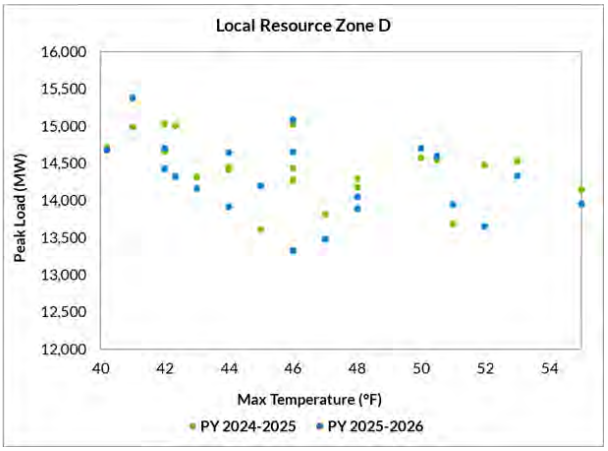


Figure 3-6: Temperature and Load Correlation for Fall and Spring Months

Summer Season
Temperature and Load Correlation
June



Winter Season
Temperature and Load Correlation
December



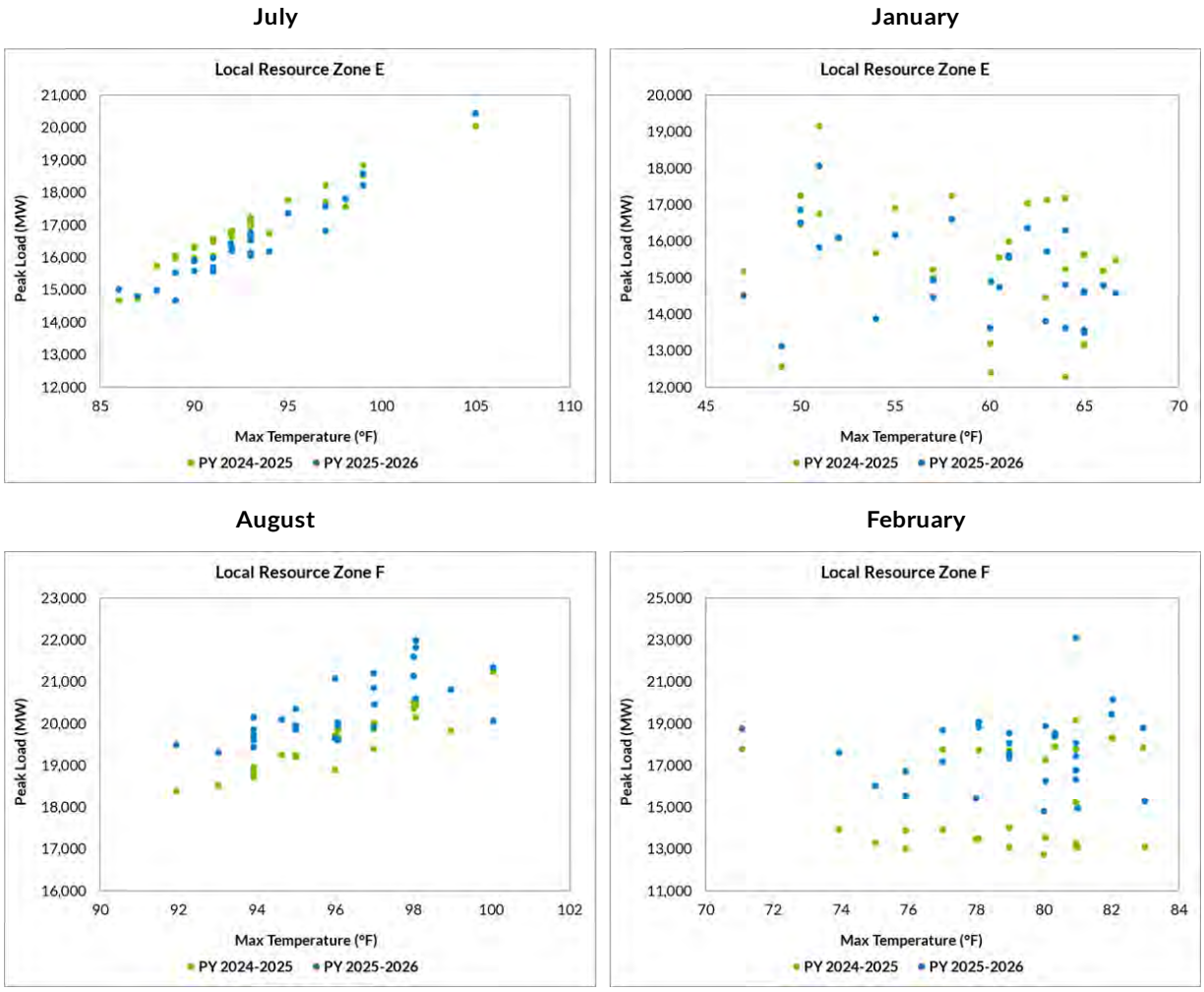


Figure 3-7: Temperature and Load Correlation for Summer and Winter Months

In the fourth step of the process and after the neural net has finished, MISO will validate the results of the neural net at extreme temperatures to smooth out any over- or under-predicted loads by comparing it against the entire 30 years of historical correlated load and weather data. During this step of the process, MISO will create a regression for the most extreme high and low temperatures in each zone to forecast out to temperatures in the 30-year range that the neural net may not have seen in the trained five-year historical load and temperature dataset.

In the fifth step of the load training process, MISO conducts a comparison of the synthetic 30-year hourly load shapes developed through the prior steps and the historical five years of hourly load data collected in the beginning of this process. During this comparative effort, MISO expects to see that the synthetic shapes are relatively in line with the historical shapes, but they should be slightly higher to account for any load reductions that were included in the historical net load shapes. If the resulting shapes are not in line with expectations, MISO will revisit step four and make any necessary changes in the regression during extreme temperatures. This may include reducing or increasing the number of data points to represent a more discrete trend.

The sixth and final step of the load training process is to average the monthly peak loads of the 30 years of predicted load shapes and adjust the load dataset to match each LRZ's total monthly zonal Coincident Peak Demand forecast

provided by the Load Serving Entities for each of the study years. To calculate the total monthly zonal Coincident Peak Demand forecasts for each year of study, the ratio of the monthly zonal Coincident Peak Demand forecast to the prompt seasonal Non-Coincident Peak Demand forecast is applied to the prompt and outyear seasonal Non-Coincident Peak Demand forecasts.

By adopting this methodology for capturing weather uncertainty, MISO can model multiple load shapes based on a functional relationship with weather. This modeling approach provides diversity in the load shapes, as well as in the peak loads observed within each zonal load shape. This approach also provides the ability to capture the frequency and duration of historical severe weather patterns.

3.4.1 Economic Load Uncertainty

To account for economic load uncertainty in the LOLE model, MISO utilized a normal distribution of electric utility forecast error accounting for projected and actual Gross Domestic Product (GDP), as well as electricity usage. The historic projections for GDP growth were taken from the Congressional Budget Office (CBO), the actual GDP growth was taken from the Bureau of Economic Analysis (BEA), and the electricity usage was taken from the U.S. Energy Information Administration (EIA). Due to a lack of state-wide projected GDP data, MISO relied on aggregated United States data when calculating economic uncertainty.

To calculate the electric utility forecast error, MISO first calculated a comparison factor representing the forecast error of actual GDP growth and historic projections. The resulting GDP forecast error was then translated into an electric utility load growth forecast error by multiplying by the rate at which electric load grew over the course of the analysis period in comparison to projected and realized GDP. Finally, a standard deviation is calculated from the electric utility load growth forecast error and used to create a normal distribution representing the probabilities of the load forecast errors (LFE) as shown in Table 3-8.

	LFE Levels				
	-2.0%	-1.0%	0.0%	1.0%	2.0%
Standard Deviation in LFE	Probability assigned to each LFE				
0.63%	0.9%	20.5%	57.3%	20.5%	0.9%

Table 3-8: Economic Uncertainty

3.5 External System

Firm imports from external areas to MISO are modeled at the individual resource level. Each firm external resource was modeled with its Installed Capacity amount and its corresponding seasonal forced outage rates, or at the contracted capacity from its corresponding Power Purchase Agreement (PPA). These resources are only modeled within the system-wide MISO PRM analyses and are not modeled when calculating the zonal LRRs, as the determination of the Local Reliability Requirements is an island-type analysis. Border External Resources and Coordinating Owner External Resources are modeled as internal MISO units and are included in the PRM and LRR analyses. External resources included as firm imports in the LOLE study were based on the amount of capacity that was either part of a Fixed Resource Adequacy Plan (FRAP), or that offered and subsequently cleared in the Planning Year 2024-2025 Planning Resource Auction (PRA).

The LOLE analyses incorporate firm exports from MISO internal units to neighboring regions, where information was available. For units with capacity sold off-system, their monthly capacities were reduced by the megawatt amount exported. These values came from PJM's Reliability Pricing Model (RPM) as well as information on exports to other external areas taken from the Independent Market Monitor (IMM) exclusion list.

Firm exports from MISO to external areas were modeled the same as in previous years. Capacity ineligible as MISO capacity due to transactions with external areas was removed from the model. Table 3-9 shows the number of firm import and export MW values in this year's study. Based on data from the Planning Year 2024-2025 PRA, MISO remained a net firm exporter.

Contracts	Summer ICAP (MW)	Summer UCAP (MW)	Fall ICAP (MW)	Fall UCAP (MW)	Winter ICAP (MW)	Winter UCAP (MW)	Spring ICAP (MW)	Spring UCAP (MW)
Imports (MW)	1,986	1,935	2,315	2,215	2,738	2,594	2,423	2,309
Exports (MW)	1,239	1,183	1,179	1,125	1,190	1,109	1,201	1,183
Net	**748**	**752**	**1,136**	**1,091**	**1,548**	**1,486**	**1,223**	**1,126**

Table 3-9: Planning Year 2025-2026 Firm Imports and Exports

Non-firm imports in the Planning Year 2025-2026 LOLE study were modeled as a seasonal probabilistic distribution representing three-year average energy imports, net of firm imports (already accounted for at the resource level), and off-system exports from MISO's internal generation. This modeling parameter is referred to as non-firm support. The distributions were developed using historic seasonal Net Scheduled Interchange (NSI) data which accounted for imports into MISO during emergency pricing hours. Firm imports cleared in the PRA for each season were subtracted from the NSI data to isolate the non-firm import values. An additional region was included in SERVM, which contained 12,000 MW of perfect generation connected to the MISO system. A distribution of the region's export capability was modeled to the upper and lower bounds. As SERVM steps through the hourly simulation, random draws on the export limits of the external region were used to represent the amount of capacity MISO could import to meet peak demand. The probability distribution of non-firm external imports used in the LOLE model is provided in Table 3-10.

	Summer	Fall	Winter	Spring
p5	1,033	-71	-377	565
p10	1,371	561	-24	829
p25	2,413	1,485	642	1,736
p50	4,351	3,346	1,817	3,720
p75	6,073	5,111	4,242	5,383
p90	7,287	6,105	5,786	6,408
p95	7,657	6,436	6,380	6,710

Table 3-10: Non-Firm External Import Distribution During Emergency Pricing Hours (MW)

3.6 Loss of Load Expectation Analysis and Metric Calculations

Upon completion of the annual LOLE study model refresh, MISO performed probabilistic analyses to determine the seasonal Planning Reserve Margin (PRM) values for Planning Year 2025-2026, as well as the seasonal Local Reliability Requirement (LRR) values for each of the 10 Local Resource Zones. The risk metrics were derived through

probabilistic modeling of the system, first solving to the industry standard annual LOLE risk target of 1 day in 10 years, or 0.1 day per year, and then solving to the minimum seasonal LOLE criteria of 0.01 LOLE for seasons demonstrating minimal risk.

3.6.1 Seasonal LOLE Distribution

To determine the seasonal LOLE distribution that is used to calculate the PRM and LRRs, MISO followed the process described in Section 68A.2.1 of Module E-1 of the MISO Tariff. This process involves first solving the LOLE model to an annual value of 0.1, then checking the seasonal distribution of the annual LOLE of 0.1. If a season had a LOLE value of at least 0.01, then it met the minimum seasonal LOLE criteria and would be set to that LOLE. If a season had less than 0.01 LOLE, additional simulations were performed until the minimum seasonal LOLE criteria of 0.01 was met.

Example: Assume the model is solved to an annual LOLE of 0.1 with 0.05 occurring in both Summer and Winter, while Fall and Spring had LOLE values of 0.00 from this simulation. In this case, the Summer and Winter seasons would not need additional analysis since both had at least 0.01 LOLE naturally when the model was solved to an annual value of 0.1. Since Fall and Spring had 0.00 LOLE, they would be assigned the minimum seasonal LOLE criteria of 0.01, and additional LOLE simulations would be performed until the minimum seasonal LOLE criteria was met through further negative adjustments to capacity in these seasons.

The annual distribution of LOLE across the four seasons at the industry standard of 1 day in 10 years, or 0.1 day per year, determined through the Planning Year 2025-2026 LOLE study, is shown in Table 3-11. The MISO-wide seasonal LOLE distribution results from the PRM analyses, and the zonal distributions result from the LRR analyses.

Region	Summer	Fall	Winter	Spring
MISO-wide	0.10	0.01	0.01	0.01
LRZ 1	0.099	0.01	0.01	0.01
LRZ 2	0.091	0.01	0.01	0.01
LRZ 3	0.098	0.01	0.01	0.01
LRZ 4	0.01	0.01	0.10	0.01
LRZ 5	0.01	0.01	0.094	0.01
LRZ 6	0.091	0.01	0.01	0.01
LRZ 7	0.099	0.01	0.01	0.01
LRZ 8	0.01	0.01	0.093	0.01
LRZ 9	0.026	0.047	0.02	0.01
LRZ 10	0.069	0.015	0.01	0.012

Table 3-11: Planning Year 2025-2026 Seasonal LOLE Distribution

3.6.2 MISO-Wide LOLE Analysis and PRM Calculation

MISO determines the appropriate PRM for each season of the applicable Planning Year based upon probabilistic analysis of reliably serving expected demand. The probabilistic analysis will utilize a Loss of Load Expectation (LOLE) study which assumes that there are no internal transmission limitations.

To determine the PRM, the LOLE model will initially be run with no adjustments to the capacity. If the LOLE is less than the minimum seasonal LOLE criteria, a negative output unit with no outage rates will be added until the LOLE

reaches the minimum seasonal LOLE criteria. This is comparable to adding load to the model. If the LOLE is greater than the minimum seasonal LOLE criteria, proxy units based on a typical combustion turbine unit of 160 MW with class average seasonal forced outage rates will be added to the model until the LOLE reaches the minimum seasonal LOLE criteria.

MISO's annual LOLE study will calculate the seasonal PRM values based on the LOLE criteria identified in the previous section. The minimum seasonal PRM requirement will be determined using the LOLE analysis by either adding a perfectly available negative output unit or by adding proxy units until a minimum LOLE of 0.01 day per season is reached.

The formulas for the PRM values for the MISO system are:

PRM ICAP % = (Installed Capacity + Firm External Support ICAP + ICAP Adjustment to meet LOLE target – MISO Coincident Peak Demand) / MISO Coincident Peak Demand

PRM UCAP % = (Unforced Capacity + Firm External Support UCAP + UCAP Adjustment to meet LOLE target – MISO Coincident Peak Demand) / MISO Coincident Peak Demand

Where Unforced Capacity (UCAP) = Installed Capacity (ICAP) x (1 – EFORd)

3.6.3 LRZ LOLE Analysis and Local Reliability Requirement Calculation

For the Local Resource Zone analyses, each zone included only the generating units within the LRZ (including Coordinating Owner External Resources and Border External Resources) and was modeled without consideration of the benefit of the LRZ's import capability. Similar to the MISO PRM analysis, Unforced Capacity is either added or removed in each LRZ such that a LOLE of 0.1 day per year is achieved when solving for the annual target and a minimum LOLE at least 0.01 day per season when solving for the minimum seasonal LOLE criteria. The minimum amount of Unforced Capacity above each LRZ's seasonal peak demand that was required to meet the reliability criteria was used to establish each LRZ's LRR.

The Planning Year 2025-2026 seasonal LRRs were determined using the LOLE analysis by first either adding or removing capacity until the annual LOLE reaches 0.1 day per year for the LRZ. If the LOLE is less than 0.1 day per year, a perfectly available negative output unit with no outage rates was added until the LOLE reaches 0.1 day per year. If the LOLE is greater than 0.1 day per year, proxy units based on a typical combustion turbine unit of 160 MW with class average seasonal forced outage rates was added to the model until the LOLE reaches 0.1 day per year.

After solving each LRZ for to the annual LOLE target of 0.1 day per year, MISO will calculate each seasonal LRR such that the summation of seasonal LOLE across the year in each zone is 1 day in 10 years, or 0.1 day per year. A minimum seasonal LOLE criterion of 0.01 will be used to calculate the LRR in seasons with less than 0.01 LOLE risk under the annual case. The seasonal Local Reliability Requirement will be determined using the LOLE analysis by either adding a perfectly available negative output unit or by adding proxy combustion turbine units until a minimum LOLE of 0.01 day per season is reached. When needed, a fraction of the marginal proxy unit was added to achieve the exact minimum seasonal LOLE criteria for the LRZ.

LRR UCAP % = (Unforced Capacity + UCAP Adjustment to meet LOLE target – Zonal Coincident Peak Demand) / Zonal Coincident Peak Demand

4 Transfer Analysis

4.1 Calculation Methodology and Process Description

Transfer analyses determined Capacity Import Limit (CIL) and Capacity Export Limit (CEL) values for LRZs in each season for Planning Year 2025-2026. Annual adjustments are made for Border External Resources and Coordinating Owner resources to determine the ZIA and ZEA in each season. Further adjustments are made for controllable exports, which are defined as exports from MISO resources that have firm capacity commitments to non-MISO load and that may be committed and dispatched by the Transmission Provider during a declared Energy Emergency. Controllable exports are subtracted from seasonal ZIA to determine seasonal CIL values. The objective of the transfer analyses is to determine constraints caused by the transfer of capacity between zones and the associated transfer capability. Multiple factors impacted the analysis when compared to previous studies, including:

- Generation
    - Loss of baseload resources being replaced by renewable resources, which impacted generation dispatch, base flows, and transmission line loadings
    - +7 GW in net installed nameplate capacity
- Transmission
    - 700+ Transmission projects at $5B
    - Approximately 150 Transmission projects above 200 kV
- Demand
    - Approximately a 4% increase in all seasons

4.1.1 Generation Pools

To determine an LRZ's import or export limit, a transfer is modeled by ramping generation up in a source subsystem and ramping generation down in a sink subsystem. The source and sink definitions depend on the limit being tested. The LRZ studied for import limits is the sink subsystem, and the adjacent MISO LBAs are the source subsystem. The LRZ studied for export limits is the source subsystem, and the rest of MISO is the sink subsystem. These are the same in all seasons for the upcoming Planning Year.

Transfers can cause potential issues, which are addressed through study assumptions. First, an abundantly large source pool spreads the impact of the transfer widely, which can cause differences in studied zones' transfer capabilities and the identified constraints. Second, ramping up generation from remote areas could cause electrically distant constraints for any given LRZ, which should not determine a zone's limit. For example, export constraints due to dispatch of LRZ 1 generation in the northwest portion of the footprint should not limit the import capability of LRZ 10, which covers the MISO portion of Mississippi.

To address these potential issues, the transfer studies limit the source pool for the import studies to the Tier 1 and Tier 2 adjacent LBAs to the study zone. Since the generation that is ramped up in export studies are contained in the study LRZ, these issues only apply to import studies. Generation within the zone studied for an export limit is ramped up and constraints are expected to be near or in the study zone.

4.1.2 Redispatch

Limited redispatch is applied after performing transfer analyses to mitigate constraints. Redispatch ensures constraints are not caused by the base dispatch and aligns with potential actions that can be implemented for the constraint by MISO control room operators. Redispatch scenarios can be designed to address multiple constraints, as

required, and may be used for constraints that are electrically close to each other or to further optimize transfer limits for several constraints requiring only minor redispatch. The redispatch assumptions include:

- The use of no more than 10 conventional fuel plants or intermittent resources
- Redispatch limit at 2,000 MW total (1,000 MW up and 1,000 MW down)
- No adjustments to nuclear units
- No adjustments to the portions of pseudo-tied units committed to non-MISO load

4.1.3 Sensitivity

Transmission Owners in a specific zone can request that a sensitivity be included in the generation-to-generation transfer to allow for the True Transfer Limit to be identified. The sensitivity would allow excluded units to be included in the generation-to-generation transfer for a zone's CIL. Excluded units mainly include nuclear units and units not to be used in zonal transfers from the latest MTEP model. This sensitivity can only be requested for a CIL study. A sensitivity would only be accepted for a particular zone if they are in a situation like that seen in Figure 4-1 below.

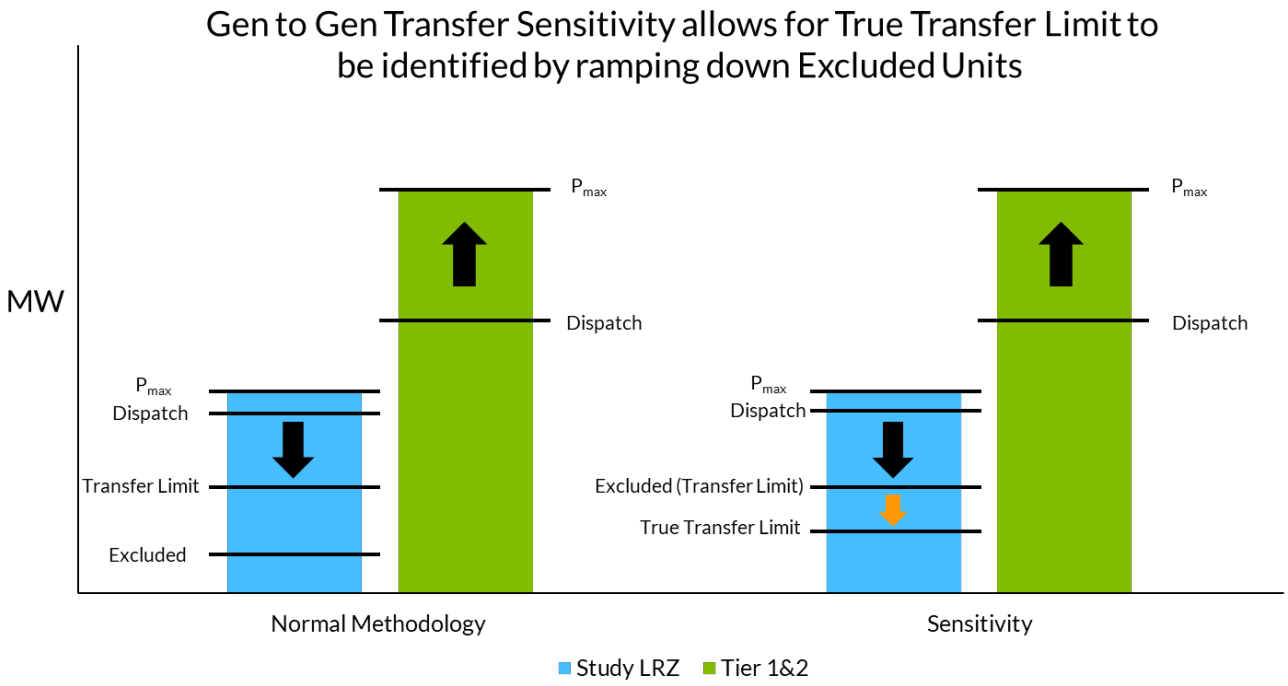


Figure 4-1: Generation-to-Generation Transfer Sensitivity

The two bars shown for the Normal Methodology category would not allow for a sensitivity to be requested by a Transmission Owner. In this situation, since the transfer limit is already identified before hitting the excluded units, a request for a generation-to-generation transfer sensitivity would not be accepted. The two bars shown for the Sensitivity category identify a situation where a request for a generation-to-generation transfer sensitivity would be accepted. When ramping down generation, the excluded units are hit before the True Transfer Limit, but since the rest of the units are excluded, the transfer limit would be identified as the point where the generation-to-generation

stops at the excluded units. With a sensitivity in place, the generation-to-generation transfer would continue into the excluded units, and the True Transfer Limit would be identified.

LRZ 10 was the only Local Resource Zone to utilize a generation-to-generation transfer sensitivity and have these results included in their Capacity Import Limit for Planning Year 2025-2026.

4.1.4 Generation Limited Transfer for CIL/CEL and ZIA/ZEA

When conducting a transfer analysis to determine import or export limits, the source subsystem might run out of generation to dispatch before identifying a valid constraint caused by a transmission limit. MISO developed a Generation Limited Transfer (GLT) process to identify transmission constraints in these situations, when possible, for both imports and exports.

After running the First Contingency Incremental Transfer Capability (FCITC) analysis to determine limits for each LRZ, MISO will determine whether a zone is experiencing a GLT (e.g., whether the first constraint would occur only after all the generation is dispatched at its maximum amount). If the LRZ experiences a GLT, MISO will adjust the base model depending on whether it is an import or export analysis and re-run the transfer analysis.

For an export study, when a transmission constraint has not been identified after all generation has been dispatched within the exporting system (LRZ under study), MISO will decrease load and generation dispatch in the study zone. The adjustment creates additional capacity to export from the zone. After the adjustments are complete, MISO will re-run the transfer analysis. If a GLT reappears, MISO will make further adjustments to the load and generation of the study zone.

For an import study, when a transmission constraint has not been identified after all generation has been dispatched within the source subsystem, MISO will decrease load and generation in the source subsystem. This increases the export capacity of the adjacent LBAs for the study zone. After the adjustments are complete, MISO will run the transfer analysis again. If a GLT reappears, MISO will make further adjustments to the model's load and generation in the source subsystem.

FCITC could indicate the transmission system can support larger thermal transfers than would be available based on installed generation for some zones—however, large variations in load and generation for any zone may lead to unreliable limits and constraints. Therefore, MISO limits load scaling for both import and export studies to 50 percent of the zone's load. In a GLT, redispatch, or GLT plus redispatch scenario, the FCITC of the most limiting constraint might exceed Zonal Export/Import Capability. If the GLT does not produce a limit for a zone, either due to a valid constraint not being identified or due to other considerations as listed in the prior paragraph, MISO shall report that LRZ as having no limit and ensure that the limit will not bind in the first iteration of the Simultaneous Feasibility Test (SFT).

4.1.5 Voltage Limited Transfer for CIL/CEL and ZIA/ZEA

Zonal imports may be limited by voltage constraints due to a decrease in the generation in the study zone. Voltage constraints might occur at lower transfer levels than thermal limits determined by linear FCITC. As such, LOLE studies may evaluate power-voltage curves for LRZs with known voltage-based transfer limitations identified through existing MISO or Transmission Owner studies. Such evaluation may also occur if an LRZ's import reaches a level where the majority of the zone's load would be served using imports from resources outside of the zone. MISO will coordinate with stakeholders as it encounters these scenarios. For Planning Year 2025-2026, only Local Resource Zones 1, 4, and 7 import analyses included voltage screening and study. No studies identified a voltage limit with lower transfer capability than the thermal limit for Planning Year 2025-2026.

4.2 Powerflow Models and Assumptions

4.2.1 Tools Used

MISO used the Siemens PTI Power System Simulator for Engineering (PSS/E) and PowerGEM Transmission Adequacy and Reliability Assessment (TARA) tools.

4.2.2 Inputs Required

Thermal transfer analysis requires Powerflow models and related input files. MISO used contingency files from MTEP[2] reliability assessment studies. Single-element contingencies in MISO and seam areas were also evaluated.

MISO developed a subsystem file to monitor its footprint and seam areas which were used for all seasons. LRZ definitions were developed as sources and sinks in the study. See Appendix A for tables containing adjacent area definitions (Tiers 1 and 2) used for this study. The monitored file includes all facilities under MISO functional control and single elements in the seam areas of 100 kV and above.

4.2.3 Powerflow Modeling

The MTEP23 models were built using MISO's Model on Demand (MOD) model data repository, with the following base assumptions (Table 4-1).

Scenario	Effective Date	Projects Applied	External Modeling	Load and Generation Profile	Wind %	Solar %
Summer 2025	July 15th	MTEP Appendix A and Target A	ERAG MMWG 2023 Series 2025 Summer Peak Load Model	Summer Peak	18%	50%
Fall 2025	October 15th	MTEP Appendix A and Target A	ERAG MMWG 2023 Series 2025 Spring Light Load Model	Fall Peak	28.5%	31%
Winter 2025-2026	January 15th	MTEP Appendix A and Target A	ERAG MMWG 2023 Series 2025 Winter Peak Load Model	Winter Peak	67%	0%
Spring 2026	April 15th	MTEP Appendix A and Target A	ERAG MMWG 2023 Series 2025 Spring Light Load Model	Spring Peak	28.5%	31%

Table 4-1: Model Assumptions

MISO excluded several types of units from the transfer analysis dispatch; these units' base dispatch remained fixed.

- Nuclear dispatch does not change for any transfer without a sensitivity
- Wind and solar resources can be ramped down, but not up
- Pseudo-tied resources were modeled at their expected commitments to non-MISO load, although portions of these units committed to MISO could participate in transfer analyses

System conditions such as load, dispatch, topology, and interchange have an impact on transfer capability. The model was reviewed as part of the base model built for MTEP24 analyses, with study files made available on MISO ShareFile. MISO worked closely with Transmission Owners and stakeholders to model the transmission system accurately, as

[2] Refer to the Transmission Planning BPM (BPM-20) for more information regarding MTEP input files. https://www.misoenergy.org/legal/business-practice-manuals/

well as to validate constraints and redispatch. Like other planning studies, transmission outage schedules were not included in the analyses. This is driven partly by limited availability of outage information as well as current transmission planning standards. Although no outage schedules were evaluated, single-element contingencies were evaluated. This includes Bulk Electric System lines, transformers, and generators.

Contingency coverage covers most of category P1 and some of category P2 outlined in Table 1 of NERC Reliability Standard TPL-001.

4.2.4 General Assumptions

MISO uses TARA to process the Powerflow model and associated input files to determine the seasonal import and export limits of each LRZ by determining the transfer capability. Transfer capability measures the ability of interconnected power systems to reliably transfer power from one area to another under specified system conditions. The incremental amount of power that can be transferred is determined through FCITC analysis. FCITC analysis and base power transfers provide the information required to calculate the First Contingency Total Transfer Capability (FCTTC), which indicates the total amount of transferable power before a constraint is identified. FCTTC is the base power transfer plus the incremental transfer capability (Equation 4-1). All published limits are based on the zone's FCTTC and may be adjusted for capacity exports.

$$First\ Contingency\ Total\ Transfer\ Capability\ (FCTTC) = Base\ Power\ Transfer + FCITC$$

Equation 4-1: Total Transfer Capability

FCITC constraints are identified under base case situations in each season or under P1 contingencies provided through the MTEP process. Linear FCITC analysis identifies the limiting constraints using a minimum transfer Distribution Factor (DF) cutoff of three percent, meaning the transfer must increase the loading on the overloaded element, under system intact or contingency conditions, by three percent or more.

A pro-rata dispatch is used, which ensures all available generators will reach their maximum dispatch level at the same time. The pro-rata dispatch is based on the MW reserve available for each unit and the cumulative MW reserve available in the subsystem. The MW reserve is found by subtracting a unit's base model generation dispatch from its maximum dispatch, which reflects the available capacity of the unit.

Table 4-2 and Equation 4-2 show an example of how one unit's dispatch is set, given all machine data for the source subsystem.

Machine	Base Model Unit Dispatch (MW)	Minimum Unit Dispatch (MW)	Maximum Unit Dispatch (MW)	Reserve MW (Unit Dispatch Max – Unit Dispatch Min)
1	20	20	100	80
2	50	10	150	100
3	20	20	100	80
4	450	0	500	50
5	500	100	500	0
			Total Reserve	**310**

Table 4-2: Example Subsystem

$$\boldsymbol{Machine\ 1\ Incremental\ Post\ Transfer\ Dispatch} = \frac{\boldsymbol{Machine\ 1\ Reserve\ MW}}{\boldsymbol{Source\ Subsystem\ Reserve\ MW}} \times \boldsymbol{Transfer\ Level\ MW}$$

$$Machine\ 1\ Incremental\ Post\ Transfer\ Dispatch = \frac{80}{310} \times 100 = 25.8$$

$$Machine\ 1\ Incremental\ Post\ Transfer\ Dispatch = 25.8$$

Equation 4-2: Machine 1 Dispatch Calculation for 100 MW Transfer

4.3 Results for CIL/CEL and ZIA/ZEA

Study constraints and associated ZIA, ZEA, CIL, and CEL for each LRZ for each season were presented and reviewed through the LOLEWG with final results for Planning Year 2025-2026 presented at the October 24th, 2024 meeting. Table 4-3 below shows the Planning Year 2025-2026 CIL and ZIA with corresponding constraint, GLT, and redispatch (RDS) information.

All zones had an identified ZIA this year. If there is no valid constraint identified, the following equation will be used where the FCITC will be replaced by the Tier 1 and Tier 2 capacity.

$$\boldsymbol{ZIA} = \boldsymbol{FCITC} + \boldsymbol{Area\ Interchange} - \boldsymbol{Border\ External\ Resources\ and\ Coordinating\ Owners}$$

Equation 4-3: Zonal Import Ability (ZIA) Calculation

LRZ1	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2025	North Appleton - Werner West 345 kV	North Appleton - Morgan 345 kV	10%	460MWx2	6023	6025
Fall 2025	Stone Lake 345/161 kV Transformer	Arrowhead 345/230 kV Transformer	None	515MWx2	5688	5690
Winter 2025-26	Laurel - Jasper 161 kV	Story County - Fernald 161 kV	None	601MWx2	5573	5575
Spring 2026	Mound City - Bismark 230 kV	Ft Thompson 1 - Chapelle 345 kV	None	352MWx2	6396	6398
LRZ2	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2025	Two Harbors - Silver Bay 115 kV	Taconite Harbor - LTV Hoyt Lakes 115 kV	None	439MWx2	4370	4370
Fall 2025	Zion - Pleasant Prairie 345 kV	Zion EC - Pleasant Prairie 345 kV	None	666MWx2	6537	6537
Winter 2025-26	Nelson Dewey 161/138 kV Transformer	Hickory Creek - Hill Valley 345 kV	None	1000MWx2	6435	6435
Spring 2026	Zion EC - Pleasant Prairie 345 kV	Zion - Pleasant Prairie 345 kV	None	624MWx2	6439	6439
LRZ3	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2025	Sub 3458 (Nebraska City) - Sub 3456 345 kV	Sub 3455 - Sub 3740 345 kV	None	302MWx2	5460	5518
Fall 2025	Sub 1211 - Sub 701 161 kV	Sub 3456 - Council Bluffs 345 kV	None	177MWx2	7704	7766
Winter 2025-26	Split Rock 7 - Split Rock 4 115 kV	Split Rock 3 - Sioux City 345 kV	None	1000MWx2	5785	5853
Spring 2026	Sub 1211 - Sub 701 161 kV	Sub 3456 - Council Bluffs 345 kV	None	138MWx2	7726	7784
LRZ4	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2025	Kincaid - Austin 345 kV	Lincoln Land Generator	5%	247MWx2	7757	8649
Fall 2025	Palmyra - Marblehead North 161 kV	Herleman - Palmyra Tap 345 kV	25%	880MWx2	7013	7908
Winter 2025-26	Sandburg 161/138 kV Transformer	Galesburg - Oak Grove 345 kV	None	1000MWx2	6457	7353
Spring 2026	Palmyra - Marblehead North 161 kV	Herleman - Palmyra Tap 345 kV	25%	866MWx2	7373	8272
LRZ5	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2025	Rezzy - Moro 138 kV	Redhawk - Moro 345 kV	None	697MWx2	4117	4117
Fall 2025	Rezzy - Moro 138 kV	Redhawk - Moro 345 kV	25%	608MWx2	4679	4679
Winter 2025-26	Hannibal West - Spalding 161 kV	Palmyra - Spencer Creek 345 kV	None	1000MWx2	4922	4922
Spring 2026	Mississippi Tap - Sioux 138 kV	Sioux Generator	10%	217MWx2	4453	4453
LRZ6	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2025	Cayuga - Nucor 345 kV	Dresser - Sugar Creek 345 kV	10%	571MWx2	8366	8650
Fall 2025	Cayuga - Cayuga Sub 345 kV	Kansas West - Sugar Creek 345 kV	None	162MWx2	8672	8970
Winter 2025-26	Kokomo Highland Park - Tipton 230 kV	Cayuga - Nucor 345 kV	None	1000MWx2	7690	7936
Spring 2026	Eugene - Cayuga Sub 345 kV	Kansas West - Sugar Creek 345 kV	None	431MWx2	9176	9491
LRZ7	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2025	Amo - Qualitech Steel 345 kV	Gibson - Wheatland 345 kV	None	1000MWx2	3569	3579
Fall 2025	Benton Harbor - Segreto 345 kV	Cook - Segreto 345 kV	None	1000MWx2	5115	5125
Winter 2025-26	Benton Harbor - Segreto 345 kV	Cook - Segreto 345 kV	None	1000MWx2	4762	4762
Spring 2026	Benton Harbor - Segreto 345 kV	Cook - Segreto 345 kV	None	643MWx2	5166	5166
LRZ8	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2025	J620 - Dermott 115 kV	Lake Village Bagby - Reed SS 115 kV	None	697MWx2	2358	2522
Fall 2025	Mount Olive - Vienna 115 kV	Mount Olive - Eldorado 500 kV	None	1000MWx2	5675	5870
Winter 2025-26	Clarksdale - Lyon 115 kV	Moon Lake - Clarkesdale 230 kV	None	1000MWx2	3432	3534
Spring 2026	Mount Olive - Vienna 115 kV	Mount Olive - Eldorado 500 kV	None	1000MWx2	6085	6250
LRZ9	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2025	Sterlington - Downsville 115 kV	Mount Olive - Eldorado 500 kV	None	1000MWx2	4361	4872
Fall 2025	Danville - Dodson 115 kV	Mount Olive - Layfield 500 kV	None	1000MWx2	4741	5242
Winter 2025-26	Arklahoma - Hot Springs East 115 kV	Arklahoma - Hot Springs West 115 kV	None	1000MWx2	4418	4995
Spring 2026	Daniel - Daniel Intermediate 1 230 kV	Daniel - Daniel Intermediate 2 230 kV	None	1000MWx2	4855	5370
LRZ 10	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2025	Ritchie - Moon Lake 230 kV	Perryville - Baxter Wilson 500 kV	None	1000MWx2	4474	4474
Fall 2025	Ritchie - Moon Lake 230 kV	Perryville - Baxter Wilson 500 kV	None	602MWx2	4508	4508
Winter 2025-26	Little Gypsy - Fairview 230 kV	Michoud - Front Street 230 kV	None	1000MWx2	3458	3458
Spring 2026	Perryville - Baxter Wilson 500 kV	Grand Gulf Generator	None	1000MWx2	4365	4365

Table 4-3: Planning Year 2025–2026 Import Limits

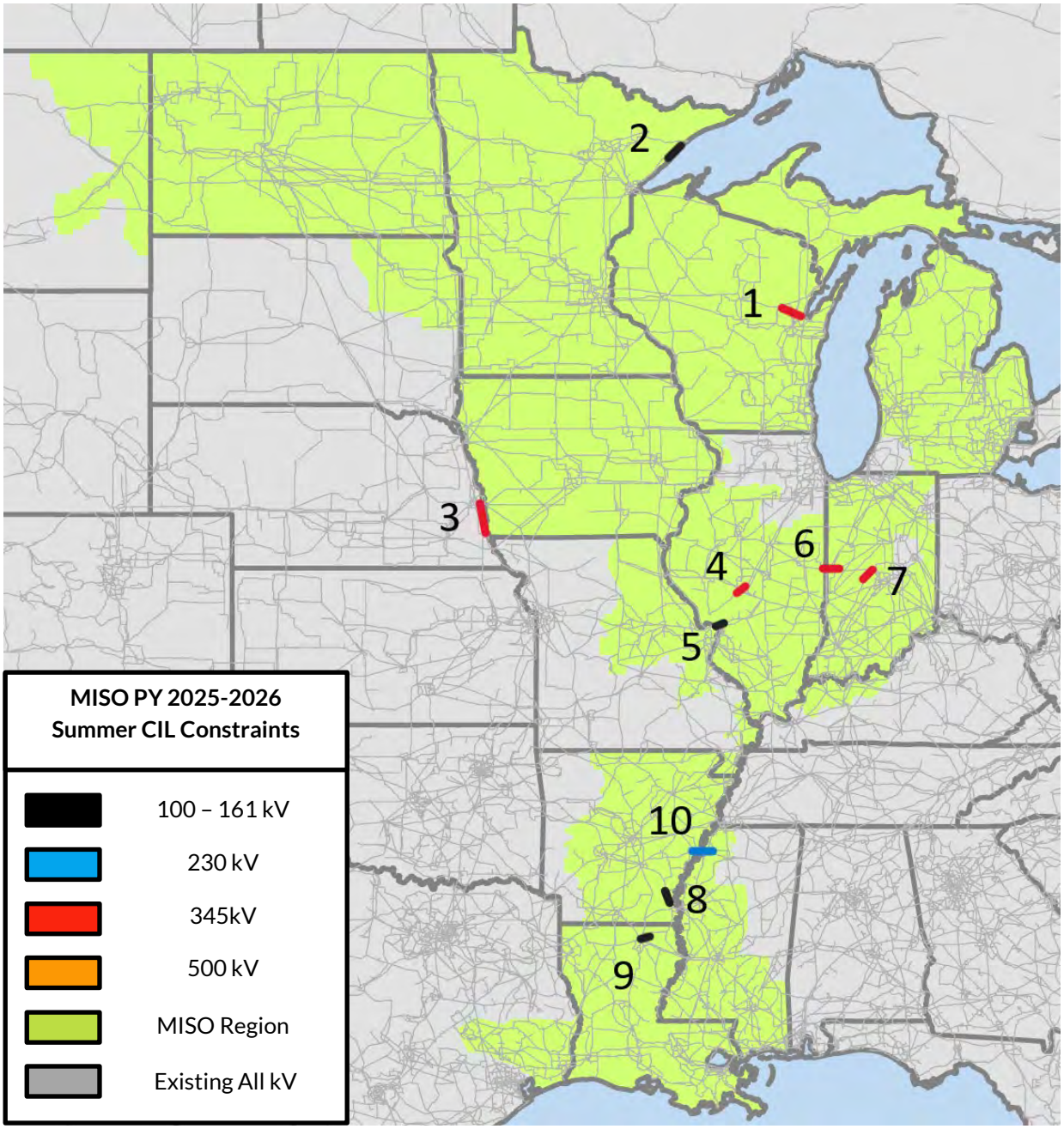


Figure 4-2: Planning Year 2025-2026 Summer Capacity Import Constraints Map

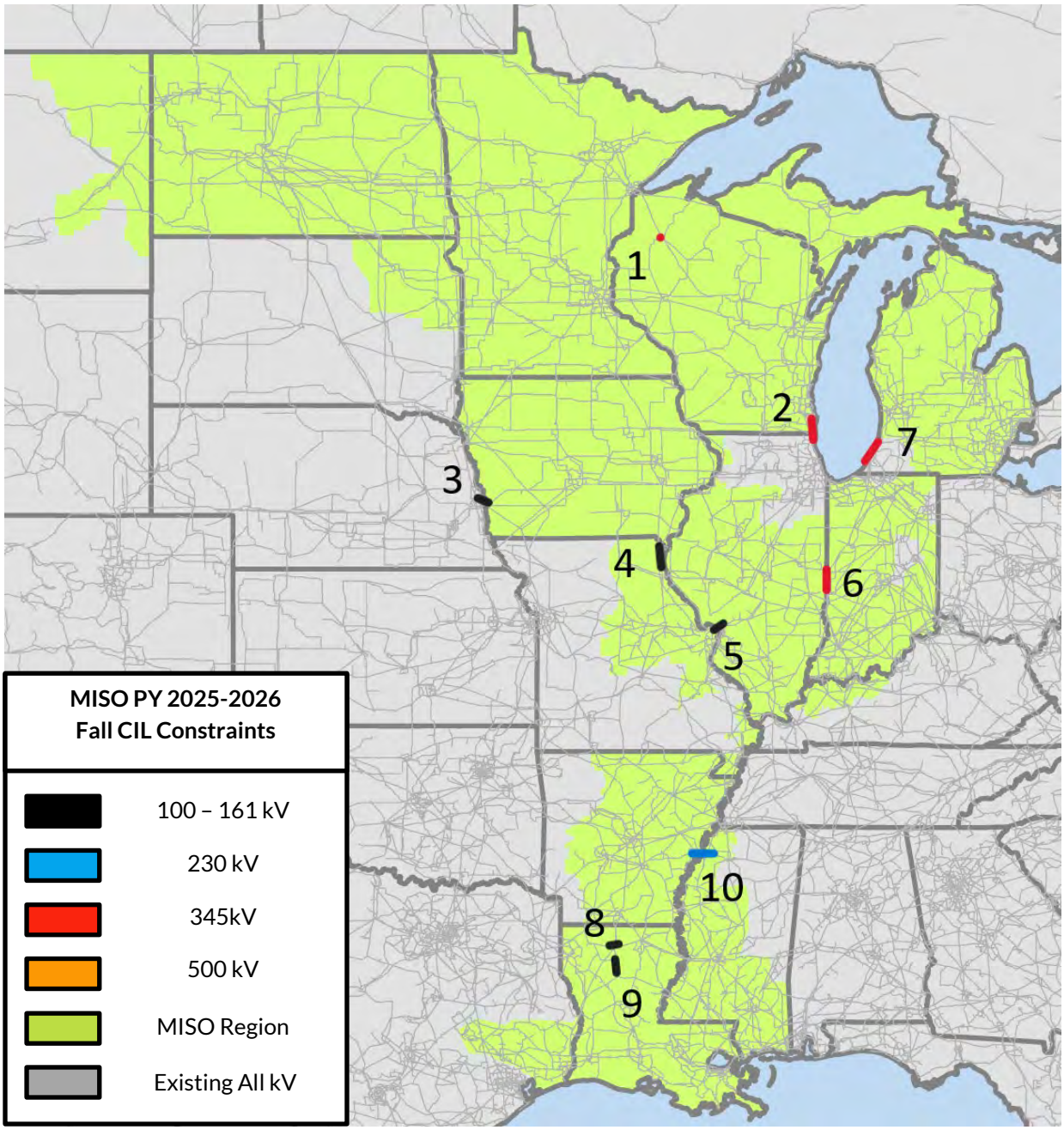


Figure 4-3: Planning Year 2025-2026 Fall Capacity Import Constraints Map

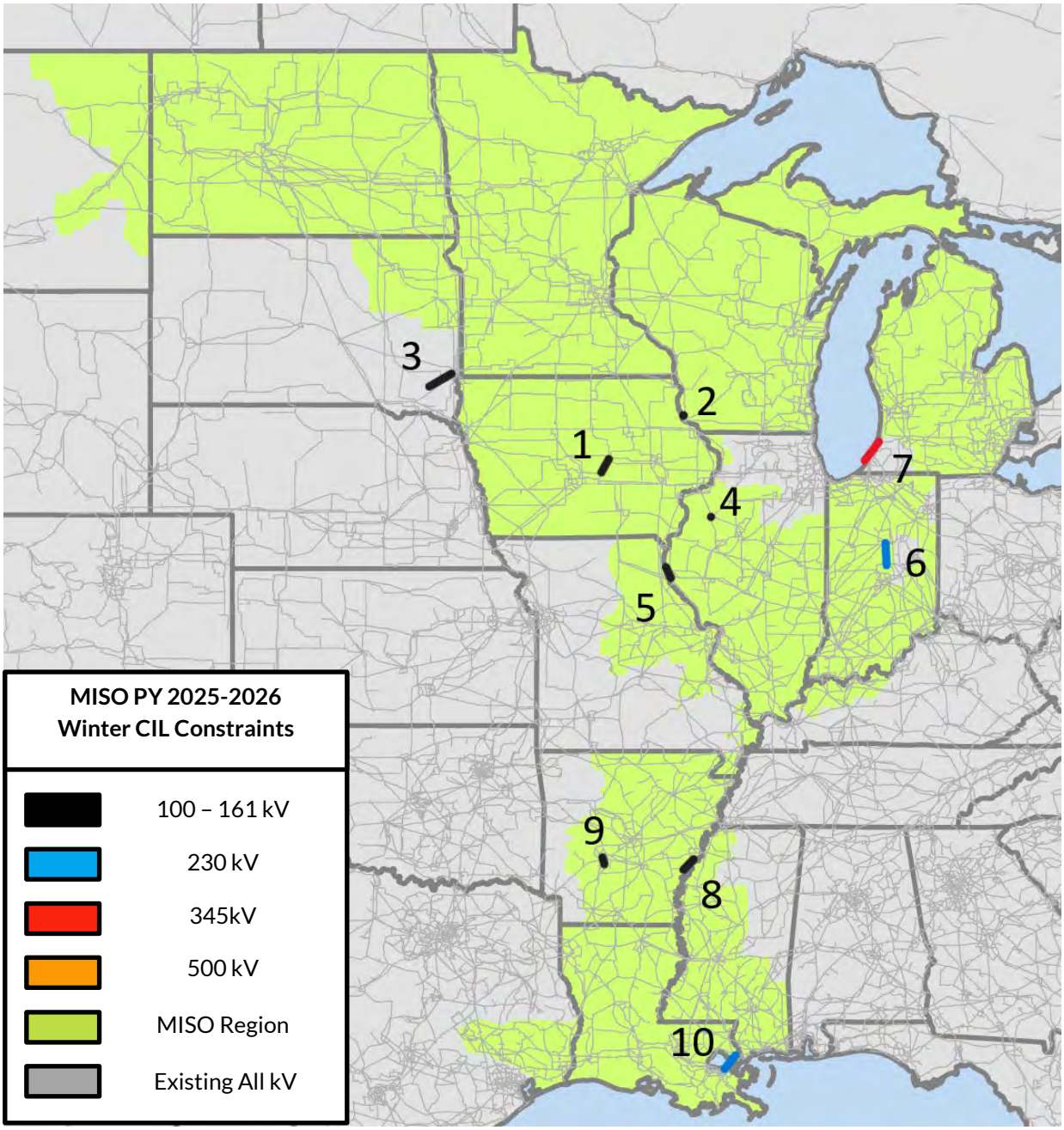


Figure 4-4: Planning Year 2025-2026 Winter Capacity Import Constraints Map

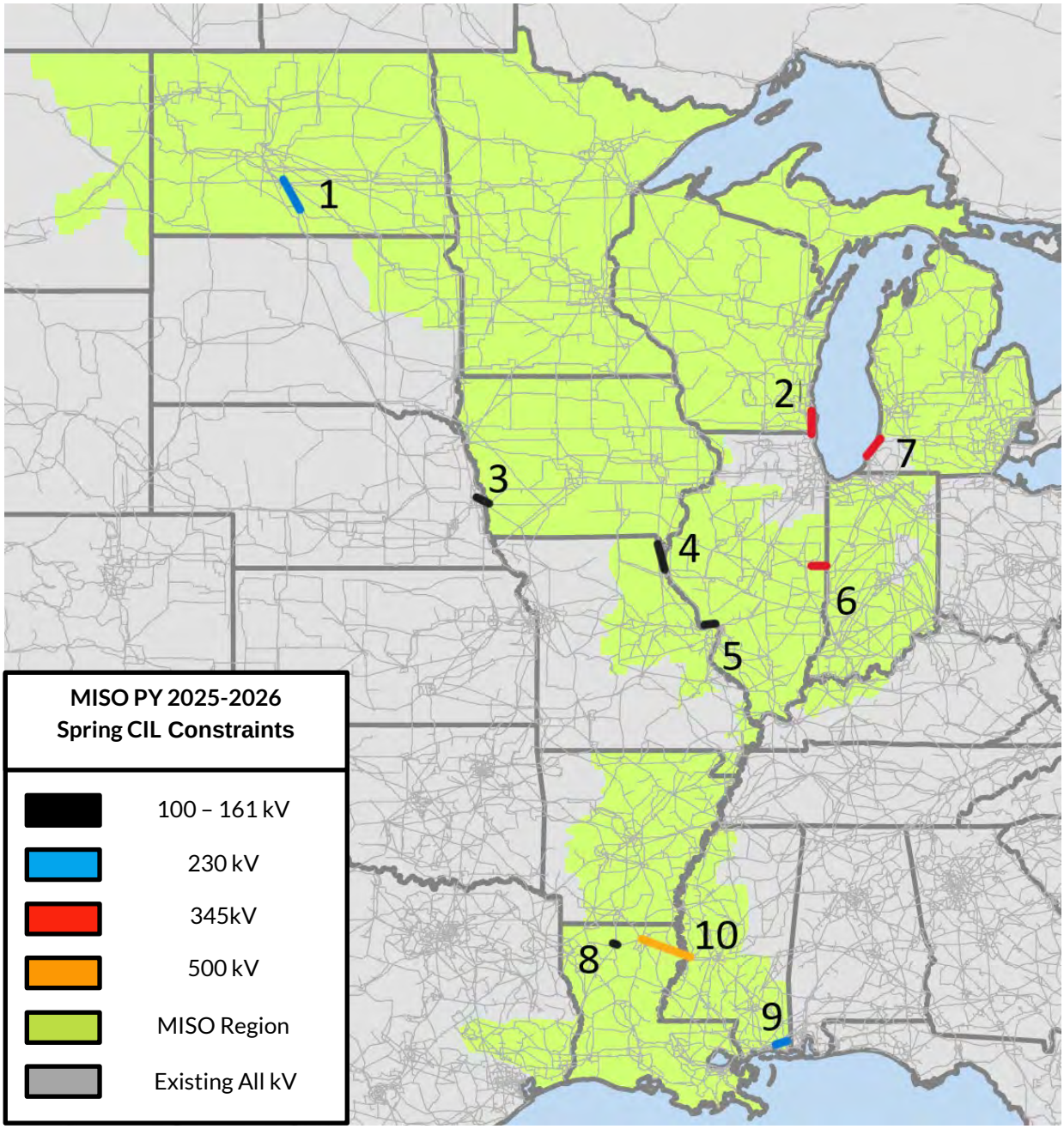


Figure 4-5: Planning Year 2025-2026 Spring Capacity Import Constraints Map

Capacity Exports Limits are found by increasing generation in the study zone and decreasing generation in the rest of the MISO footprint to create a transfer. Table 4-4 below shows the Planning Year 2025-2026 CEL and ZEA with corresponding constraint, GLT, and redispatch information.

LRZ1	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2025	Split Rock 4 - Sioux Falls 230 kV	Split Rock 3 - Sioux City 345 kV	None	293MWx2	3993	3991
Fall 2025	Adams - Mitchell County 345 kV	Disconnect Blackhawk Reactor	None	270MWx2	6167	6165
Winter 2025-26	Split Rock 7 - Split Rock 4 115 kV	Split Rock - Sioux City 345 kV	None	721MWx2	3593	3591
Spring 2026	Adams - Mitchell County 345 kV	Disconnect Blackhawk Reactor	None	279MWx2	5285	5283
LRZ2	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2025	Neevin - Butte Des Morts 138 kV	Neevin-Woodenshoe 138 kV	25%	633MWx2	4614	4614
Fall 2025	Sherman Street - Sunnyvale 115 kV	Arpin - Rocky Run 345 kV	10%	909MWx2	4259	4259
Winter 2025-26	Granville - Butler 138 kV	Arcadian-Granville 345 kV	20%	561MWx2	4793	4793
Spring 2026	Berryville - Paris 138 kV	Paris 345/138 kV Transformer	30%	674MWx2	6119	6119
LRZ3	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2025	No Limiting Element	None	50%	None	4713	4655
Fall 2025	No Limiting Element	None	50%	None	5924	5862
Winter 2025-26	Council Bluffs - Sub 3456 345 kV	Arbor Hill - Raccoon Trail 345 kV	None	561MWx2	7480	7412
Spring 2026	No Limiting Element	None	50%	None	6039	5981
LRZ4	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2025	Alsey - Winchester 138 kV	Alsey - Ballard 138 kV	40%	577MWx2	5352	4460
Fall 2025	Marion - Marion South 161 kV	Silver Mine Substation	None	1000MWx2	5069	4174
Winter 2025-26	No Limiting Element	None	50%	None	5531	4635
Spring 2026	Marion - Marion South 161 kV	Silver Mine Substation	None	212MWx2	5880	4981
LRZ5	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2025	No Limiting Element	None	45%	None	3939	3939
Fall 2025	No Limiting Element	None	50%	None	5816	5816
Winter 2025-26	No Limiting Element	None	50%	None	4814	4814
Spring 2026	No Limiting Element	None	50%	None	5797	5797
LRZ6	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2025	Gibson - Douglas 345 kV	AB Brown - Posey East 345 kV	40%	70MWx2	7165	6881
Fall 2025	AEP Rockport - Grandview 138 kV	AB Brown - Reid 345 kV	None	539MWx2	5471	5173
Winter 2025-26	AB Brown - AB Brown Reactor 138 kV	AB Brown - Reid 345 kV	None	518MWx2	1911	1665
Spring 2026	Holland - Dubois 138 kV	Duff - Francisco 345 kV	None	487MWx2	6706	6391
LRZ7	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2025	Monroe - Lallendorf 345 kV	Morocco - Allen Junction 345 kV	15%	1000MWx2	5726	5716
Fall 2025	Monroe - Lallendorf 345 kV	Morocco - Allen Junction 345 kV	None	1000MWx2	5168	5158
Winter 2025-26	Morocco - Allen Junction 345 kV	Monroe - Lallendorf 345 kV	None	1000MWx2	5712	5712
Spring 2026	Monroe - Lallendorf 345 kV	Morocco - Allen Junction 345 kV	None	1000MWx2	5499	5499
LRZ8	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2025	No Limiting Element	None	50%	641MWx2	6509	6345
Fall 2025	Cash - Jonesboro 161 kV	Independence - Power Line Road 500 kV	None	1000MWx2	4219	4024
Winter 2025-26	Freeport - Cordova 500 kV	Sans Souci - Driver 500 kV	20%	422MWx2	3783	3681
Spring 2026	Freeport - Cordova 500 kV	Sans Souci - Driver 500 kV	None	382MWx2	3724	3559
LRZ9	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2025	Montgomery - Clarence 230 kV	Montgomery - Winfield 230 kV	None	1000MWx2	4286	3775
Fall 2025	Ray Braswell - Northside Drive 230 kV	Ray Braswell - Lakeover 500 kV	None	1000MWx2	4173	3672
Winter 2025-26	Little Gypsey - Fairview 230 kV	Michoud - Front Street 230 kV	None	1000MWx2	3618	3041
Spring 2026	Ray Braswell - Northside Drive 230 kV	Ray Braswell - Lakeover 500 kV	None	1000MWx2	4146	3631
LRZ10	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2025	Batesville - Tallahatchie 161 kV	Batesville - East Batesville 161 kV	None	710MWx2	2097	2097
Fall 2025	Lake Village Bagby - Macon Lake 115 kV	Lake Village Bagby - Reed 115 kV	None	650MWx2	3164	3164
Winter 2025-26	Batesville - Tallahatchie 161 kV	Choctaw - Clay 500 kV	None	710MWx2	2028	2028
Spring 2026	Batesville - Tallahatchie 161 kV	Batesville - East Batesville 161 kV	None	526MWx2	3072	3072

Table 4-4: Planning Year 2025–2026 Export Limits

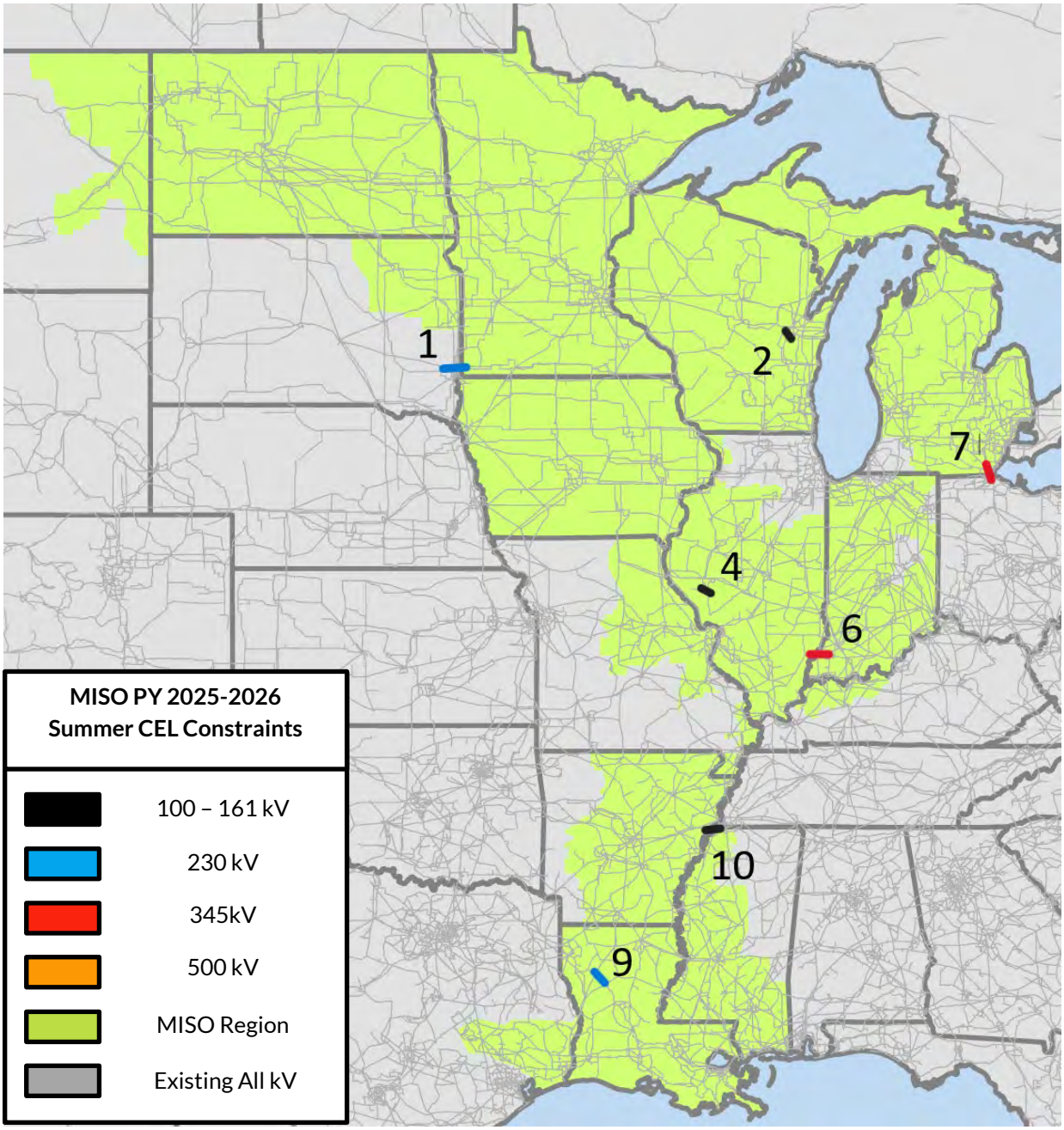


Figure 4-6: Planning Year 2025-2026 Summer Export Constraint Map

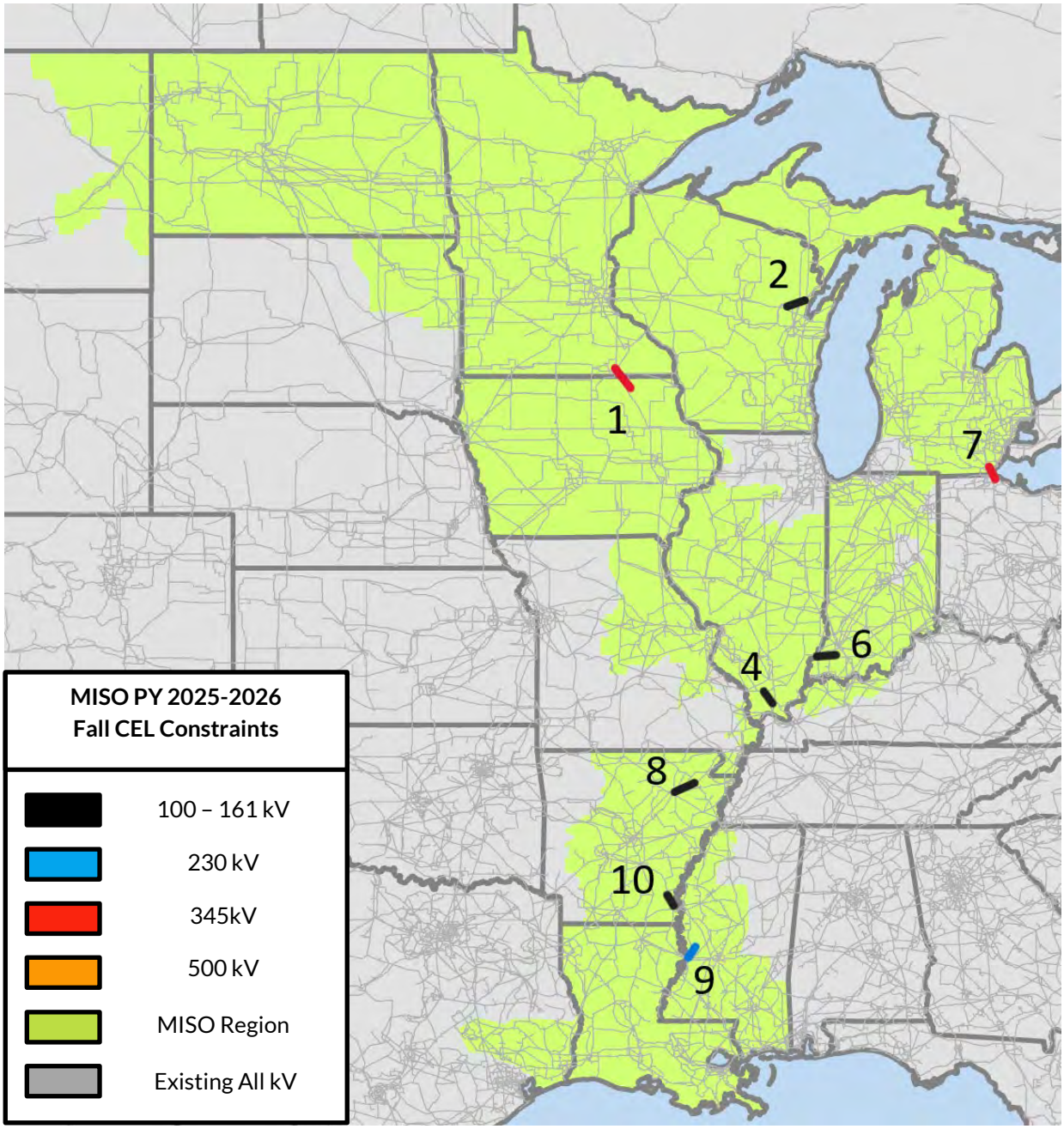


Figure 4-7: Planning Year 2025-2026 Fall Export Constraint Map

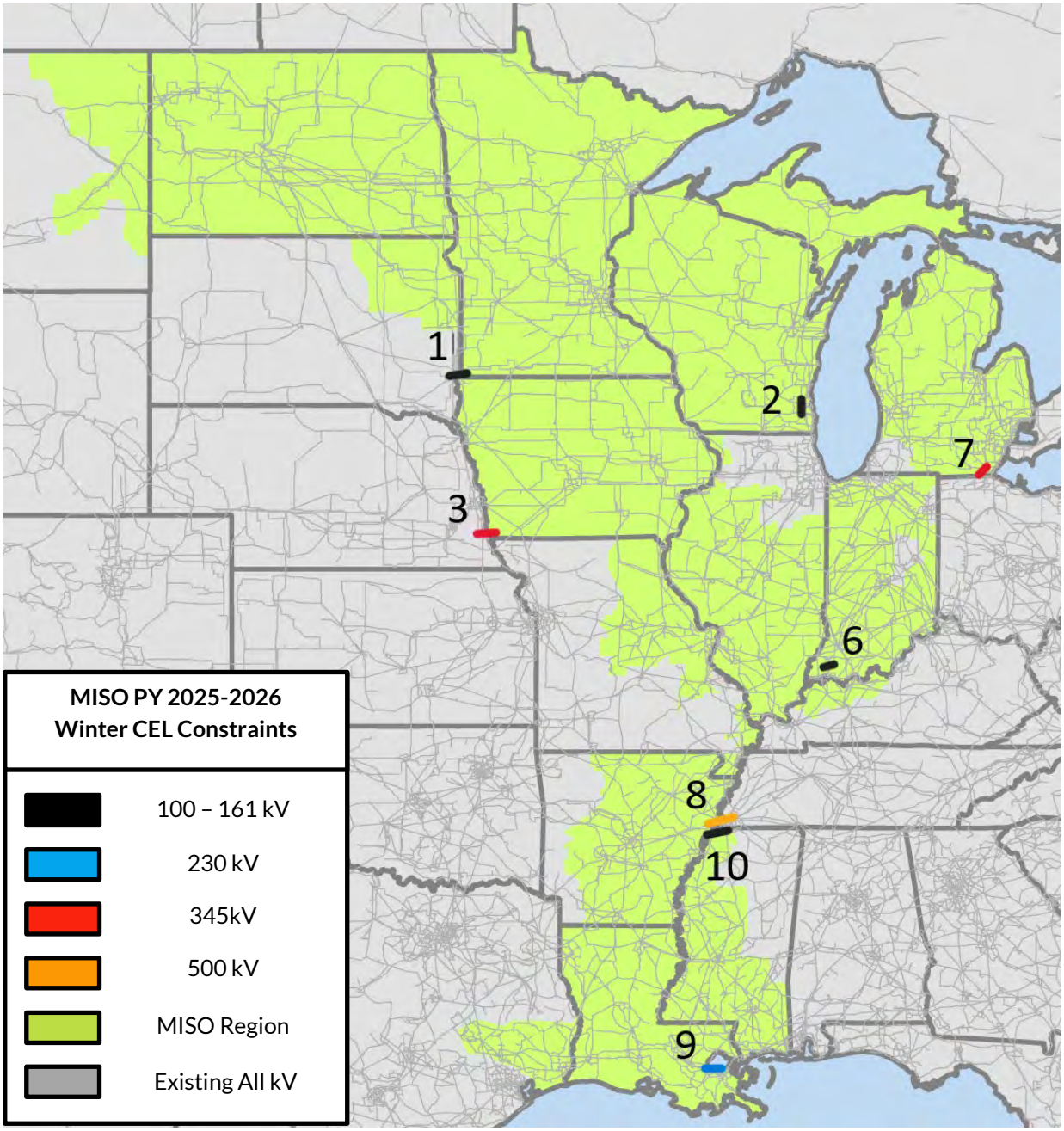


Figure 4-8: Planning Year 2025-2026 Winter Export Constraint Map

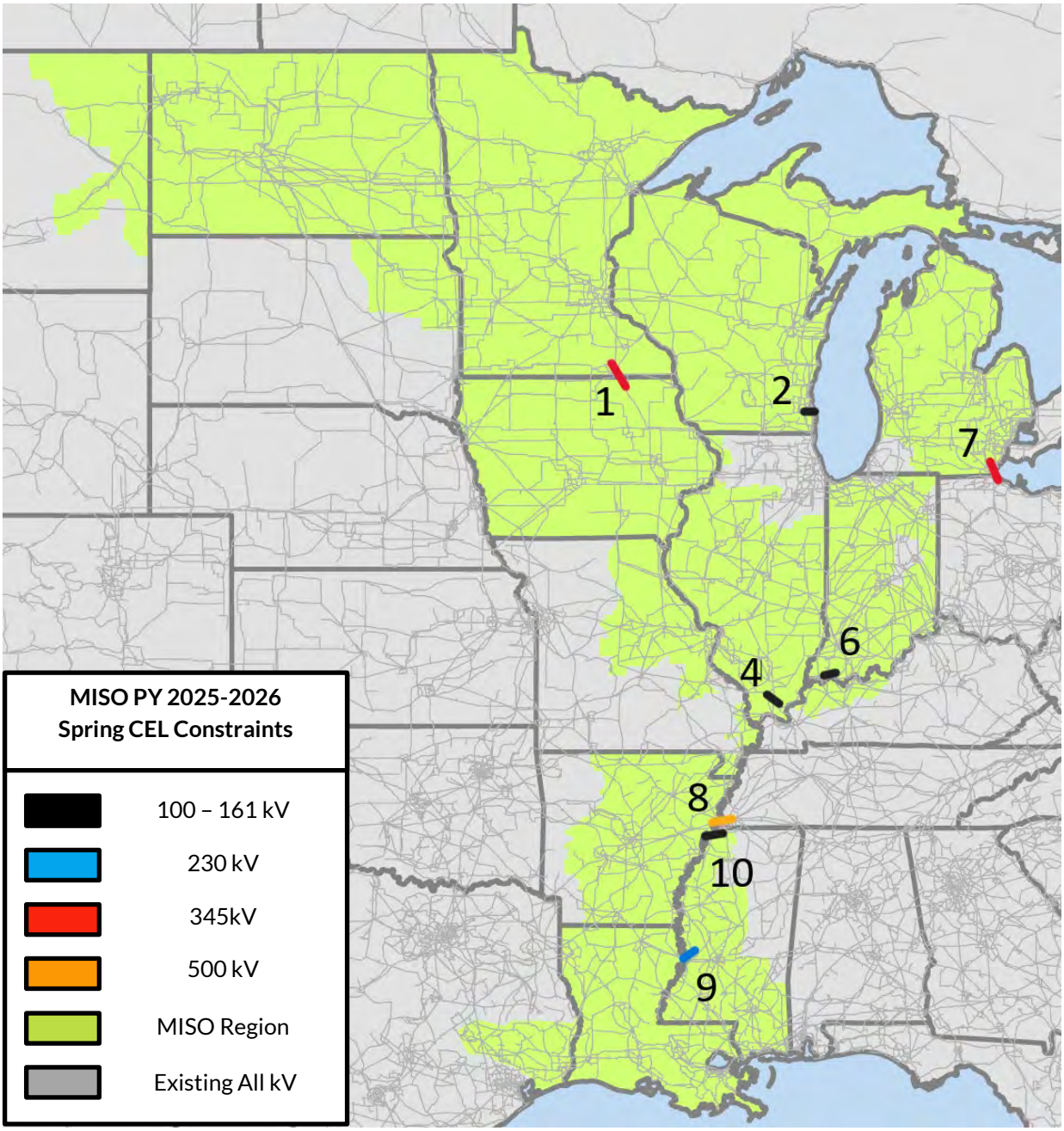


Figure 4-9: Planning Year 2025-2026 Spring Export Constraint Map

Appendix A: Capacity Import Limit Tier 1 & 2 Source Subsystem Definitions

MISO Local Resource Zone 1

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
XEL / 600	ALTW / 627	WEC / 295
MP / 608	ALTE / 694	MIUP / 296
SMMPA / 613	WPS / 696	AMMO / 356
GRE / 615	MGE / 697	AMIL / 357
OTP / 620		MPW / 633
MDU / 661		MEC / 635
BEPC-MISO / 663		
DPC / 680		

MISO Local Resource Zone 2

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #	
WEC / 295	METC / 218	NIPS / 217	OTP / 620
MIUP / 296	XEL / 600	ITCT / 219	MPW / 633
ALTE / 694	MP / 608	AMMO / 356	MEC / 635
WPS / 696	ALTW / 627	AMIL / 357	
MGE / 697	DPC / 680	SMMPA / 613	
UPPC / 698		GRE / 615	

MISO Local Resource Zone 3

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #	
ITCM / 627	AMMO / 356	HE / 207	GLHB / 362
MPW / 633	AMIL / 357	DEI / 208	MP / 608
MEC / 635	XEL / 600	NIPS / 217	GRE / 615
	SMMPA / 613	WEC / 295	OTP / 620
	DPC / 680	CWLP / 360	WPS / 696
	ALTE / 694	SIPC / 361	MGE / 697

MISO Local Resource Zone 4

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #	
AMIL / 357	HE / 207	SIGE / 210	DPC / 680
CWLP / 360	DEI / 208	IPL / 216	ALTE / 694
SIPC / 361	NIPS / 217	METC / 218	
GLHB / 362	BREC / 314	HMPL / 315	
GLH / 373	AMMO / 356	XEL / 600	
	ITCM / 627	SMMPA / 613	
	MEC / 635	MPW / 633	

MISO Local Resource Zone 5

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #	
CWLD / 333	AMIL / 357	HE / 207	SMMPA / 613
AMMO / 356	GLHB / 362	DEI / 208	MPW / 633
	ALTW / 627	NIPS / 217	DPC / 680
	MEC / 635	CWLP / 360	ALTE / 694
		SIPC / 361	
		XEL / 600	

MISO Local Resource Zone 6

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
HE / 207	METC / 218	ITCT / 219
DEI / 208	AMIL / 357	MIUP / 296
SIGE / 210	SIPC / 361	AMMO / 356
IPL / 216		CWLP / 360
NIPS / 217		GLHB / 362
BREC / 314		ALTW / 627
HMPL / 315		MEC / 635

MISO Local Resource Zone 7

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
METC / 218	NIPS / 217	DEI / 208
ITCT / 219	MIUP / 296	WEC / 295
		AMIL / 356
		WPS / 696
		UPPC / 698

MISO Local Resource Zone 8

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
EES-EAI / 327	EES-EMI / 326	LAGN / 332
	EES / 351	SMEPA / 349
		CLEC / 502
		LAFA / 503

MISO Local Resource Zone 9

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
LAGN / 332	EES-EMI / 326	SMEPA / 349
EES / 351	EES-EAI / 327	
CLEC / 502		
LAFA / 503		
LEPA / 504		

MISO Local Resource Zone 10

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
EES-EMI / 326	EES-EAI / 327	LAGN / 332
SMEPA / 349	EES / 351	CLEC / 502
		LAFA / 503

Appendix B: Compliance Conformance Table

Requirements under: Standard BAL-502-RF-03	Response
R1 The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall:	The Planning Year 2025-2026 LOLE Study Report is the annual Resource Adequacy Analysis for the peak season of June 2025 through May 2026 and beyond. Analysis of Planning Year 2025-2026 is in Sections 1.2 and 2.1. Analysis of Future Years 2025-2034 is included in Appendix D as an addendum to the study report.
R1.1 Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year[1] analyzed (per R1.2) being equal to 0.1. (This is comparable to a "one day in 10 years" criterion).	Section 3.6 of this report outlines the utilization of LOLE in the reserve margin determination. "The risk metrics were derived through probabilistic modeling of the system, first solving to the industry standard annual LOLE risk target of 1 day in 10 years, or 0.1 day per year, and then solving to the minimum seasonal LOLE criteria of 0.01 LOLE for seasons demonstrating minimal risk.
R1.1.1 The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the loss of Load probability.	Section 3.4 of this report. "Direct Control Load Management and Interruptible Demand types of demand response were included in the LOLE model as resources. Demand response is dispatched in the LOLE model to avoid load shed during simulation when all other available generation has been exhausted."
R1.1.2 The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median forecast peak Net Internal Demand (planning reserve margin).	Section 1.2 of this report. "…the ratio of MISO capacity to forecasted MISO system peak demand yielded a Planning Reserve Margin UCAP…"
R1.2 Be performed or verified separately for each of the following planning years.	Covered in the segmented R1.2 responses below.
R1.2.1 Perform an analysis for Year One.	In Sections 1.2 and 2.1, a full analysis was performed for Planning Year 2025-2026.
R1.2.2 Perform an analysis or verification at a minimum for one year in the 2 through 5-year period and at a minimum one year in the 6 though 10-year period.	Analysis of Planning Years 2028-2029 and 2030-2031 are included in Appendix D as an addendum to the study report.

Requirements under: Standard BAL-502-RF-03	Response
R1.2.2.1 If the analysis is verified, the verification must be supported by current or past studies for the same planning year.	Analysis was performed.
R1.3 Include the following subject matter and documentation of its use:	Covered in the segmented R1.3 responses below.
R1.3.1 Load forecast characteristics: • Median (50:50) forecast peak load • Load Forecast Uncertainty (reflects variability in the Load forecast due to weather and regional economic forecasts) • Load Diversity • Seasonal Load Variations • Daily demand modeling assumptions (firm, interruptible) • Contractual arrangements concerning curtailable/Interruptible Demand	Median forecasted load – In Section 3.4 of this report: "The sixth and final step of the load training process is to average the monthly peak loads of the 30 years of predicted load shapes and adjust the load dataset to match each LRZ's total monthly zonal Coincident Peak Demand forecast provided by the Load Serving Entities for each of the study years." Load Forecast Uncertainty – A detailed explanation of the weather and economic uncertainties is given in Section 3.4. Load Diversity / Seasonal Load Variations — In Section 3.4 of this report: "Every year, the Load Serving Entities submit new load forecasts to MISO by November 1 and, every year, MISO utilizes these load forecasts in the load development process for the LOLE study to align the load in the model with the anticipated load growth forecasted within each Local Resource Zone. The Planning Year 2025-2026 LOLE analysis used a load training process pared with neural net software to establish a correlated relationship between the most recent 5 years of historical weather and load data. This relationship was then applied to 30 years of hourly historical load data to create 30 years of load shapes for each LRZ to capture both load diversity and seasonal variability." Demand Modeling Assumptions / Curtailable and Interruptible Demand — All Load Modifying Resources must first meet registration requirements through Module E of the MISO Tariff. As stated in Section 3.2.6: "Each demand response program was modeled individually with a monthly capability, limited by duration and the number of times each program can be called upon for each season."

Requirements under: Standard BAL-502-RF-03	Response
R1.3.2 Resource characteristics: • Historic resource performance and any projected changes • Seasonal resource ratings • Modeling assumptions of firm capacity purchases from and sales to entities outside the Planning Coordinator area • Resource planned outage schedules, deratings, and retirements • Modeling assumptions of intermittent and energy limited resource such as wind and cogeneration • Criteria for including planned resource additions in the analysis	Section 3.2 details how historic performance data and seasonal ratings are gathered and includes discussion of future units and the modeling assumptions for intermittent capacity resources. A more detailed explanation of firm capacity purchases and sales is in Section 3.5.
R1.3.3 Transmission limitations that prevent the delivery of generation reserves.	Annual MTEP deliverability analysis identifies transmission limitations preventing delivery of generation reserves. Additionally, Section 4 of this report details the transfer analysis to capture transmission constraints limiting capacity transfers.
R1.3.3.1 Criteria for including planned Transmission Facility additions in the analysis.	Inclusion of the planned transmission addition assumptions is detailed in Section 4.2.3.
R1.3.4 Assistance from other interconnected systems including multi-area assessment considering Transmission limitations into the study area.	Section 3.5 provides the analysis on the treatment of external support assistance and limitations.

Requirements under: Standard BAL-502-RF-03	Response
R1.4 Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included: • Availability and deliverability of fuel • Common mode outages that affect resource availability • Environmental or regulatory restrictions of resource availability • Any other demand (Load) response programs not included in R1.3.1 • Sensitivity to resource outage rates • Impacts of extreme weather/drought conditions that affect unit availability • Modeling assumptions for emergency operation procedures used to make reserves available • Market resources not committed to serving Load (uncommitted resources) within the Planning Coordinator area	Fuel availability, environmental restrictions, common mode outage, and extreme weather conditions are all part of the historical availability performance data that goes into the unit's EFORd statistic. The use of the EFORd values is covered in Section 3.2.1. The use of demand response programs is mentioned in Section 3.2.6. The effects of resource outage characteristics on the reserve margin are outlined in Section 3.6.2 by examining the difference between PRM ICAP and PRM UCAP values.
R1.5 Consider Transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included.	Transmission maintenance schedules were not included in the analysis of the transmission system due to the limited availability of reliable long-term maintenance schedules and minimal impact to the results of the analysis. However, Section 4 treats worst-case theoretical outages by performing First Contingency Total Transfer Capability (FCTTC) analysis for each LRZ, by modeling NERC Category P0 (system intact) and Category P1 (N-1) contingencies.
R1.6 Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis.	MISO internal resources are among the quantities documented in the tables provided in Sections 1 and 2.
R1.7 Document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis.	MISO load is among the quantities documented in the tables provided in Sections 1 and 2.
R2 The Planning Coordinator shall annually document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis.	In Sections 1 and 2, the peak load and estimated amount of resources for Planning Year 2025-2026 are shown. This includes the detail for each transmission constrained sub-area.
R2.1 This documentation covers each of the years in year one through ten.	Appendix D details the future Planning Year analysis.

Requirements under: Standard BAL-502-RF-03	Response
R2.2 This documentation includes the Planning Reserve margin calculated per requirement R1.1 for each of the three years in the analysis.	The prompt Planning Year seasonal PRM values are covered in Section 1.2. The outyear Planning Years 4 (2028-2029) and 6 (2030-2031) are covered in Appendix D.
R2.3 The documentation as specified per requirement R2.1 and R2.2 shall be publicly posted no later than 30 calendar days prior to the beginning of Year One.	The final Planning Year 2025-2026 LOLE Study Report was posted publicly in November 2024, several months prior to the start of the applicable Planning Year.
R3 The Planning Coordinator shall identify any gaps between the needed amount of planning reserves defined in Requirement R1, Part 1.1 and the projected planning reserves documented in Requirement R2.	Sections 1 and 2 show the differences between the needed amount and the projected planning reserves for Planning Year 2025-2026. The amount of planning reserves needed for the outyear Planning Years 4 (2028-2029) and 6 (2030-2031) are covered in Appendix D.

Appendix C: Acronyms List Table

CEL	Capacity Export Limit
CIL	Capacity Import Limit
CPNode	Commercial Pricing Node
DF	Distribution Factor
EFORd	Equivalent Forced Outage Rate demand
ELCC	Effective Load Carrying Capability
ERZ	External Resource Zone
EUE	Expected Unserved Energy
FERC	Federal Energy Regulatory Commission
FCITC	First Contingency Incremental Transfer Capability
FCTTC	First Contingency Total Transfer Capability
GADS	Generator Availability Data System
GLT	Generation Limited Transfer
GVTC	Generation Verification Test Capacity
ICAP	Installed Capacity
LBA	Local Balancing Authority
LCR	Local Clearing Requirement
LFE	Load Forecast Error
LFU	Load Forecast Uncertainty
LOLE	Loss of Load Expectation
LOLEWG	Loss of Load Expectation Working Group
LRR	Local Reliability Requirement
LRZ	Local Resource Zones
LSE	Load Serving Entity
MARS	Multi-Area Reliability Simulation
MECT	Module E Capacity Tracking
MISO	Midcontinent Independent System Operator
MOD	Model on Demand
MTEP	MISO Transmission Expansion Plan
MW	Megawatt
MWh	Megawatt hours
NERC	North American Electric Reliability Corporation

PRA	Planning Resource Auction
PRM	Planning Reserve Margin
PRM ICAP	PRM Installed Capacity
PRM UCAP	PRM Unforced Capacity
PRMR	Planning Reserve Margin Requirement
PSS E	Power System Simulator for Engineering
RCF	Reciprocal Coordinating Flowgate
RDS	Redispatch
RPM	Reliability Pricing Model
SAC	Seasonal Accredited Capacity
SERVM	Strategic Energy & Risk Valuation Model
SPS	Special Protection Scheme
TARA	Transmission Adequacy and Reliability Assessment
UCAP	Unforced Capacity
XEFORd	Equivalent Forced Outage Rate demand with adjustment to exclude events outside management control
ZIA	Zonal Import Ability
ZEA	Zonal Export Ability

Appendix D: Outyear PRM Results

For Planning Year 2028-2029, the ratio of MISO capacity to forecasted MISO system peak demand yielded a Planning Reserve Margin UCAP of 8.5 percent for the Summer season. Numerous values and calculations went into determining the four-year-out MISO system seasonal PRM UCA, supporting values are seen in Table D-1. In addition to the LOLE results, SERVM has the ability to calculate several other probabilistic metrics, resulting values for Loss of Load Hours (LOLH) and Expected Unserved Energy (EUE) for each season of the 2028-2029 Planning Year are shown below in Table D-2.

D.1 Planning Year 2028-2029 MISO Planning Reserve Margin Results

MISO Planning Reserve Margin (PRM)	PY 2028-2029 Summer	PY 2028-2029 Fall	PY 2028-2029 Winter	PY 2028-2029 Spring	Formula Key
MISO System Peak Demand (MW)	129,963	114,031	109,039	104,253	[A]
Installed Capacity (ICAP) (MW)	153,551	150,473	157,792	158,083	[B]
Unforced Capacity (UCAP) (MW)	143,488	138,424	137,443	144,560	[C]
Firm External Support ICAP (MW)	1,986	2,315	2,738	2,423	[D]
Firm External Support UCAP (MW)	1,935	2,215	2,594	2,309	[E]
Adjustment to ICAP (MW)	(4,350)	(9,400)	(8,640)	(14,850)	[F]
Adjustment to UCAP (MW)	(4,350)	(9,400)	(8,640)	(14,850)	[G]
ICAP PRM Requirement (PRMR) (MW)	151,187	143,388	151,890	145,657	[H] = [B]+[D]+[F]
UCAP PRM Requirement (PRMR) (MW)	141,073	131,239	131,398	132,019	[I] = [C]+[E]+[G]
MISO PRM ICAP	**16.3%**	**25.7%**	**39.3%**	**39.7%**	[J]=[H]-[A]/[A]
MISO PRM UCAP	**8.5%**	**15.1%**	**20.5%**	**26.6%**	[K]=[I]-[A]/[A]

Table D-1: Planning Year 2028-2029 MISO System Planning Reserve Margins

D.1.1 Additional Risk Metric Statistics

MISO LOLE Statistics	PY 2028-2029 Summer	PY 2028-2029 Fall	PY 2028-2029 Winter	PY 2028-2029 Spring
Loss of Load Expectation (LOLE) [days/year]	0.100	0.010	0.010	0.010
Loss of Load Hours (LOLH) [hours/year]	0.143	0.011	0.013	0.013
Expected Unserved Energy (EUE) [megawatt-hours/year]	307.123	12.808	11.574	14.615

Table D-2: PY 2028-2029 Additional Risk Metric Statistics

D.2 Planning Year 2030-2031 MISO Planning Reserve Margin Results

For Planning Year 2030-2031, the ratio of MISO capacity to forecasted MISO system peak demand yielded a Planning Reserve Margin UCAP of 8.5 percent for the Summer season. Numerous values and calculations went into determining the six-year-out MISO system seasonal PRM UCA, supporting values are seen in Table D-3. In addition to the LOLE results, SERVM has the ability to calculate several other probabilistic metrics, resulting values for Loss of Load Hours (LOLH) and Expected Unserved Energy (EUE) for each season of the 2030-2031 Planning Year are shown below in Table D-4.

MISO Planning Reserve Margin (PRM)	**PY 2030-2031** Summer	**PY 2030-2031** Fall	**PY 2030-2031** Winter	**PY 2030-2031** Spring	**Formula Key**
MISO System Peak Demand (MW)	131,381	115,692	110,450	105,291	[A]
Installed Capacity (ICAP) (MW)	158,093	155,519	162,465	160,212	[B]
Unforced Capacity (UCAP) (MW)	147,627	143,109	141,998	146,462	[C]
Firm External Support ICAP (MW)	1,986	2,315	2,738	2,423	[D]
Firm External Support UCAP (MW)	1,935	2,215	2,594	2,309	[E]
Adjustment to ICAP (MW)	(7,075)	(11,500)	(10,687)	(14,600)	[F]
Adjustment to UCAP (MW)	(7,075)	(11,500)	(10,687)	(14,600)	[G]
ICAP PRM Requirement (PRMR) (MW)	153,004	146,335	154,516	148,036	[H] = [B]+[D]+[F]
UCAP PRM Requirement (PRMR) (MW)	142,487	133,825	133,906	134,171	[I] = [C]+[E]+[G]
MISO PRM ICAP	**16.5%**	**26.5%**	**39.9%**	**40.6%**	[J]=[H]-[A]/[A]
MISO PRM UCAP	**8.5%**	**15.7%**	**21.2%**	**27.4%**	[K]=[I]-[A]/[A]

Table D-3: Planning Year 2030-2031 MISO System Planning Reserve Margins

D.2.1 Additional Risk Metric Statistics

MISO LOLE Statistics	**PY 2030-2031** Summer	**PY 2030-2031** Fall	**PY 2030-2031** Winter	**PY 2030-2031** Spring
Loss of Load Expectation (LOLE) [days/year]	0.100	0.010	0.010	0.010
Loss of Load Hours (LOLH) [hours/year]	0.138	0.010	0.012	0.012
Expected Unserved Energy (EUE) [megawatt-hours/year]	309.609	15.855	10.990	11.952

Table D-4: PY 2030-2031 Additional Risk Metric Statistics

D.3 MISO Planning Reserve Margin Outyear Projections

Tables D-5, D-6, D-7, and D-8 show the outyear seasonal PRM projections. Years one, four, and six were probabilistically modeled. PRM projections in years two, three, and five are the result of interpolation of the years studied and years seven through ten are the resulting extrapolations of the outyear analyses.

Metric	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
PRM ICAP	15.7%	15.9%	16.1%	16.3%	16.4%	16.5%	16.6%	16.8%	16.9%	17.1%
PRM UCAP	7.9%	8.1%	8.3%	8.5%	8.5%	8.5%	8.6%	8.7%	8.8%	8.9%
Demand (GW)	123.6	125.7	127.8	130.0	130.7	131.4	132.9	134.5	136.1	137.6
ICAP (GW)	141.9	145.8	149.7	153.6	155.8	158.1	161.3	164.6	167.8	171.0

Table D-5: MISO Summer Planning Reserve Margin Outyear Projections

Metric	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
PRM ICAP	25.3%	25.5%	25.6%	25.7%	26.1%	26.5%	26.7%	27.0%	27.2%	27.4%
PRM UCAP	14.9%	14.9%	15.0%	15.1%	15.4%	15.7%	15.8%	16.0%	16.2%	16.3%
Demand (GW)	108.1	110.1	112.1	114.0	114.9	115.7	117.2	118.7	120.2	121.8
ICAP (GW)	142.7	145.3	147.9	150.5	153.0	155.5	158.1	160.6	163.2	165.7

Table D-6: MISO Fall Planning Reserve Margin Outyear Projections

Metric	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
PRM ICAP	38.6%	38.9%	39.1%	39.3%	39.6%	39.9%	40.1%	40.4%	40.7%	40.9%
PRM UCAP	18.4%	19.1%	19.8%	20.5%	20.9%	21.2%	21.8%	22.4%	22.9%	23.5%
Demand (GW)	103.9	105.6	107.3	109.0	109.7	110.4	111.8	113.1	114.4	115.7
ICAP (GW)	147.4	150.9	154.3	157.8	160.1	162.5	165.5	168.5	171.5	174.5

Table D-7: MISO Winter Planning Reserve Margin Outyear Projections

Metric	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
PRM ICAP	38.8%	39.1%	39.4%	39.7%	40.2%	40.6%	41.0%	41.3%	41.7%	42.1%
PRM UCAP	25.3%	25.7%	26.2%	26.6%	27.0%	27.4%	27.9%	28.3%	28.7%	29.2%
Demand (GW)	98.7	100.5	102.4	104.3	104.8	105.3	106.6	107.9	109.3	110.6
ICAP (GW)	144.5	149.0	153.6	158.1	159.1	160.2	163.4	166.5	169.6	172.8

Table D-8: MISO Spring Planning Reserve Margin Outyear Projections

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-7

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

Filed September 5, 2025

Exhibit 84

MISO 2024-25 Auction Results

CORRECTIONS

Reposted 4/26/24

Slides Updated : 28, 40

Planning Resource Auction

Results for Planning Year 2024-25

April 25, 2024

MISO is projected to meet most Planning Year 2024-25 resource adequacy requirements; however, pressure persists with reduced capacity surplus across the region and a shortfall in Zone 5

- The Planning Resource Auction (PRA) clearing prices are flat across the region, except for fall and spring in Zone 5 (Missouri)
  - Zone 5 cleared at seasonal Cost of New Entry (CONE) in fall and spring due to inadequate capacity to meet its Local Clearing Requirement, driven by resource retirements and seasonal outages

All Zones (except Zone 5)	Zone 5:
• **Summer:** $30/MW-day	• **Summer:** $30/MW-day
• **Fall:** $15/MW-day	• **Fall:** $719.81/MW-day
• **Winter:** $0.75/MW-day	• **Winter:** $0.75/MW-day
• **Spring:** $34.10/MW-day	• **Spring:** $719.81/MW-day

- Capacity surplus across MISO eroded 30% in summer, primarily in the North/Central region
  - Retirements, reduced imports and higher requirements are insufficiently offset by new capacity
  - Trends are similar across other seasons except for winter which has a higher surplus
- Receding surplus, coupled with emerging risks due to fleet transition and new load additions, continue to pressure resource adequacy
- MISO's efforts under the Reliability Imperative — Reliability-Based Demand Curve, accreditation and attributes — are timely and responsive to the evolving resource adequacy risk

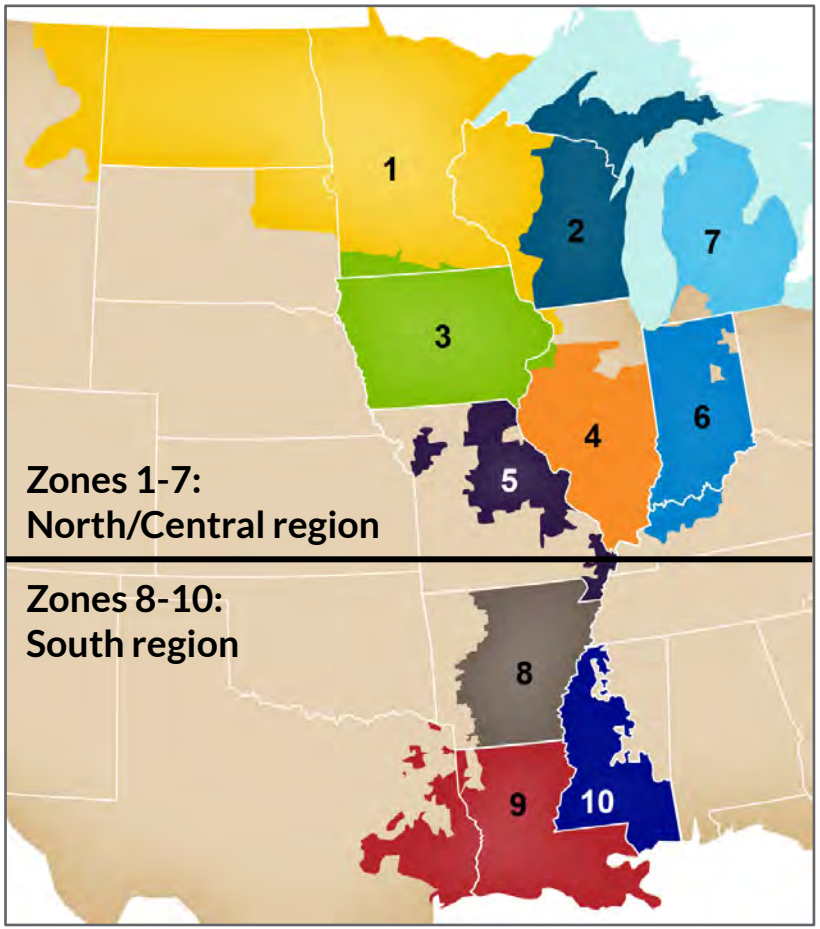
The 2024 PRA demonstrated sufficient capacity at the regional, sub-regional and zonal levels except for Zone 5

2024 PRA Results

Zone	Local Balancing Authorities	Summer	Fall	Winter	Spring
			(Price $/MW-Day)		
1	DPC, GRE, MDU, MP, NSP, OTP, SMP	30.00	15.00	0.75	34.10
2	ALTE, MGE, UPPC, WEC, WPS, MIUP	30.00	15.00	0.75	34.10
3	ALTW, MEC, MPW	30.00	15.00	0.75	34.10
4	AMIL, CWLP, SIPC, GLH	30.00	15.00	0.75	34.10
5	AMMO, CWLD	30.00	719.81	0.75	719.81
6	BREC, CIN, HE, IPL, NIPS, SIGE	30.00	15.00	0.75	34.10
7	CONS, DECO	30.00	15.00	0.75	34.10
8	EAI	30.00	15.00	0.75	34.10
9	CLEC, EES, LAFA, LAGN, LEPA	30.00	15.00	0.75	34.10
10	EMBA, SME	30.00	15.00	0.75	34.10
ERZ	KCPL, OPPD, WAUE (SPP), PJM, OVEC, LGEE, AECI, SPA, TVA	30.00	15.00	0.75	34.10

Highlighted values are CONE pricing

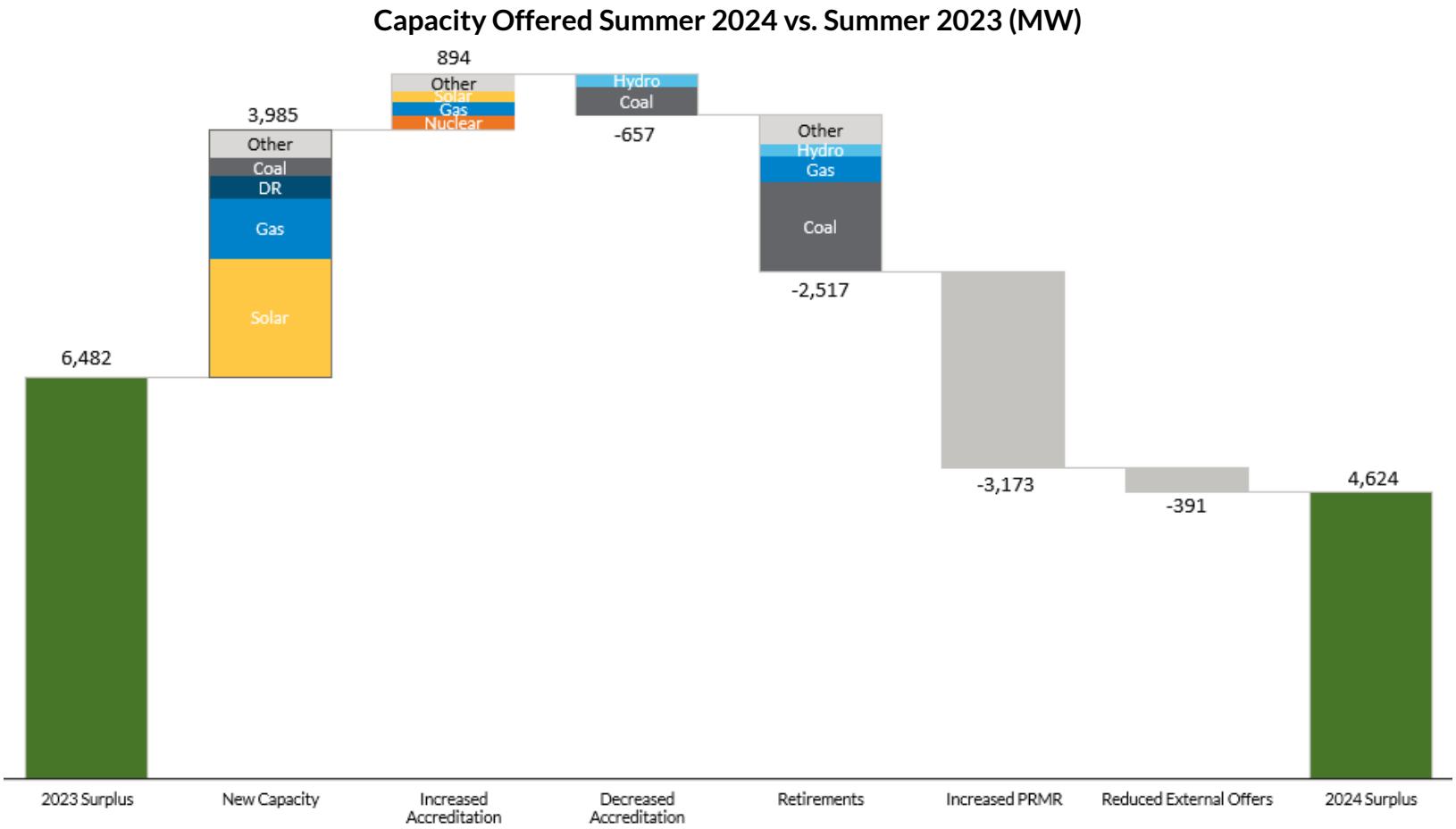
MISO Resource Adequacy Zones



ERZ: External Resource Zones

The MISO footprint showed approximately a 30% decrease in surplus but remained adequate

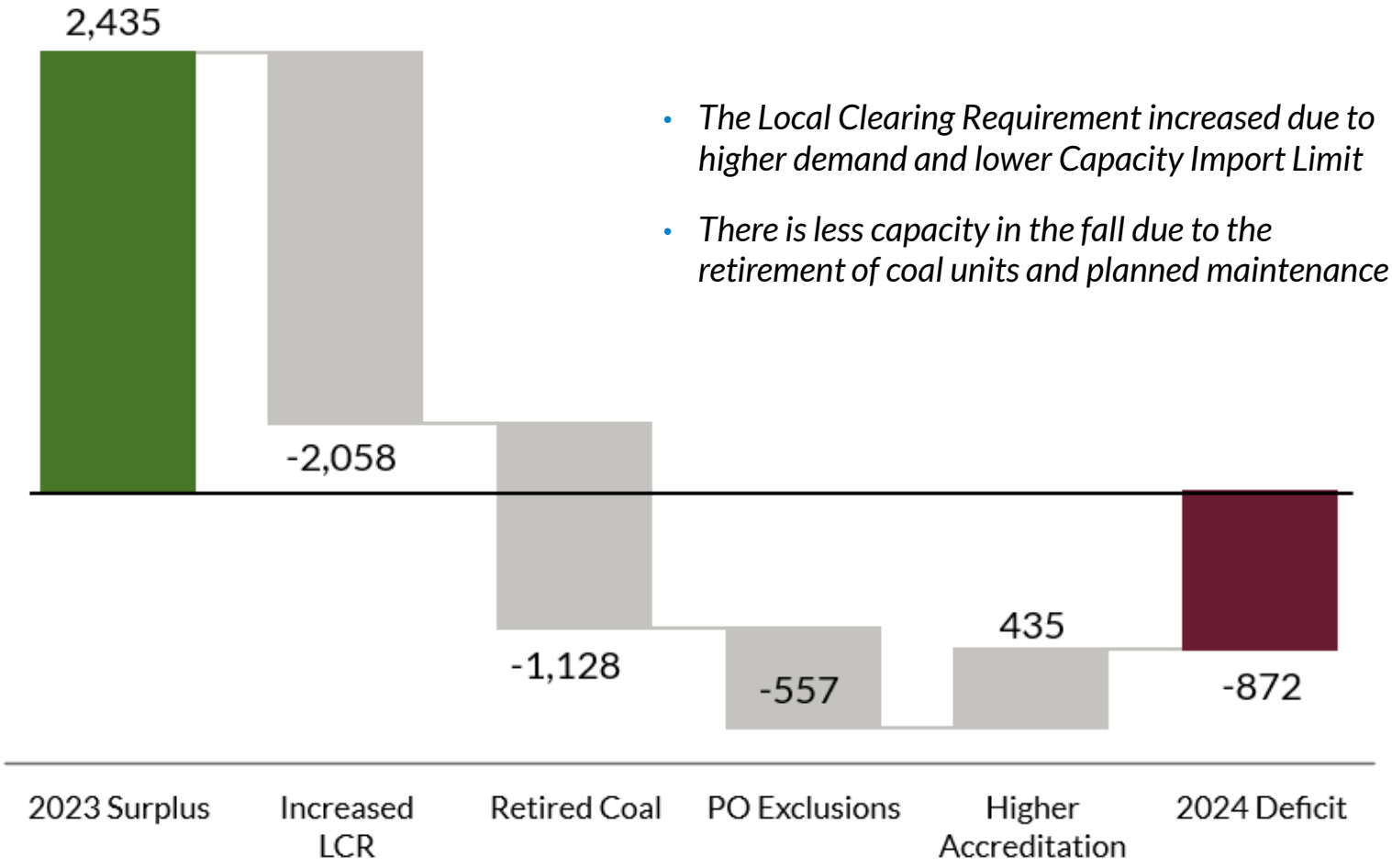
Reduced surplus driven by retirements, increased PRMR and reduced external offers



DR: Demand Response *Capacity indicated is offered accredited value*

A combination of higher Local Clearing Requirement and reduced capacity contributed to Zone 5 deficiency in the fall

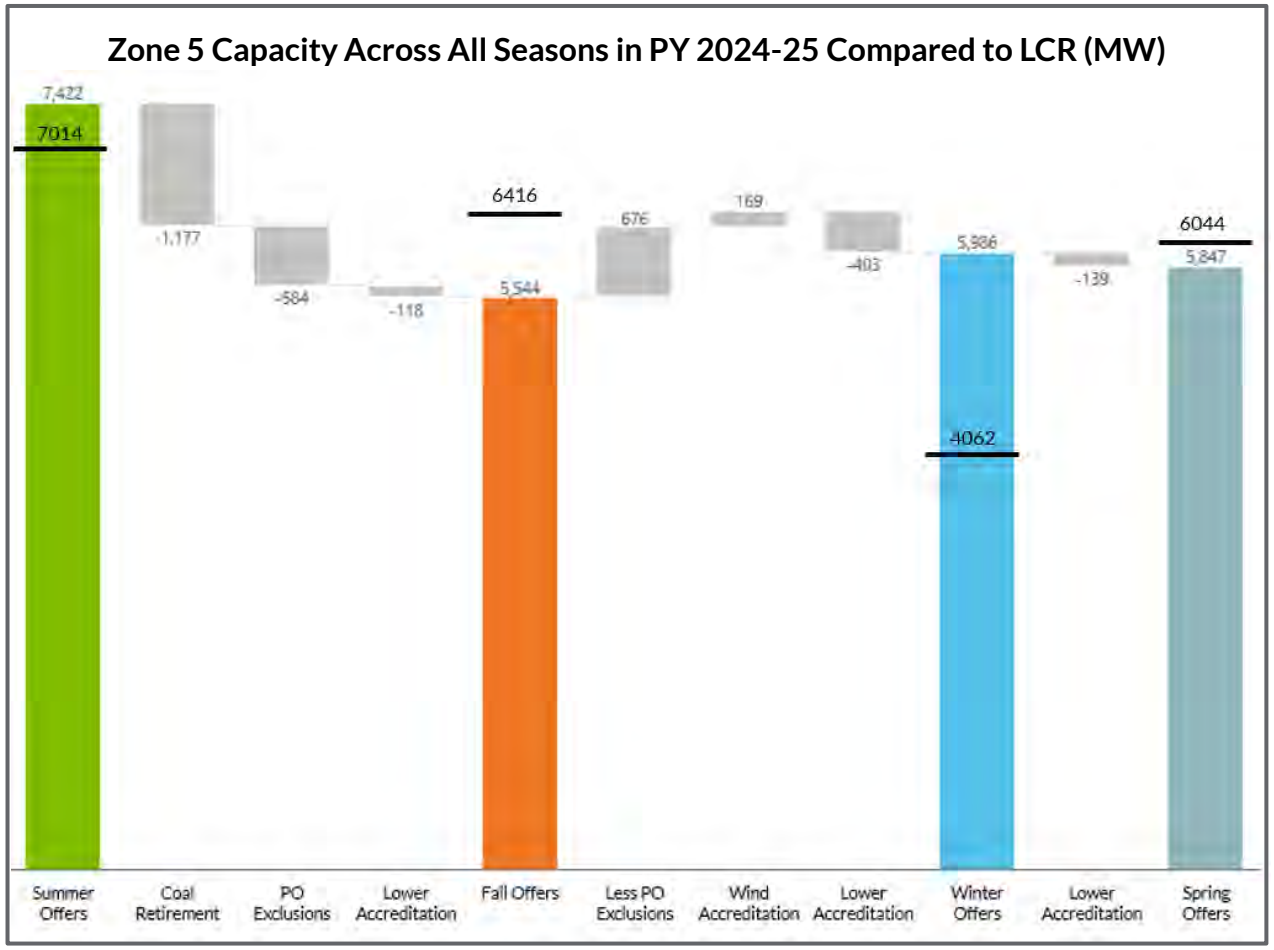
Zone 5 Fall 2024 Capacity Changes Year-Over-Year (MW)



- *The Local Clearing Requirement increased due to higher demand and lower Capacity Import Limit*
- *There is less capacity in the fall due to the retirement of coal units and planned maintenance*

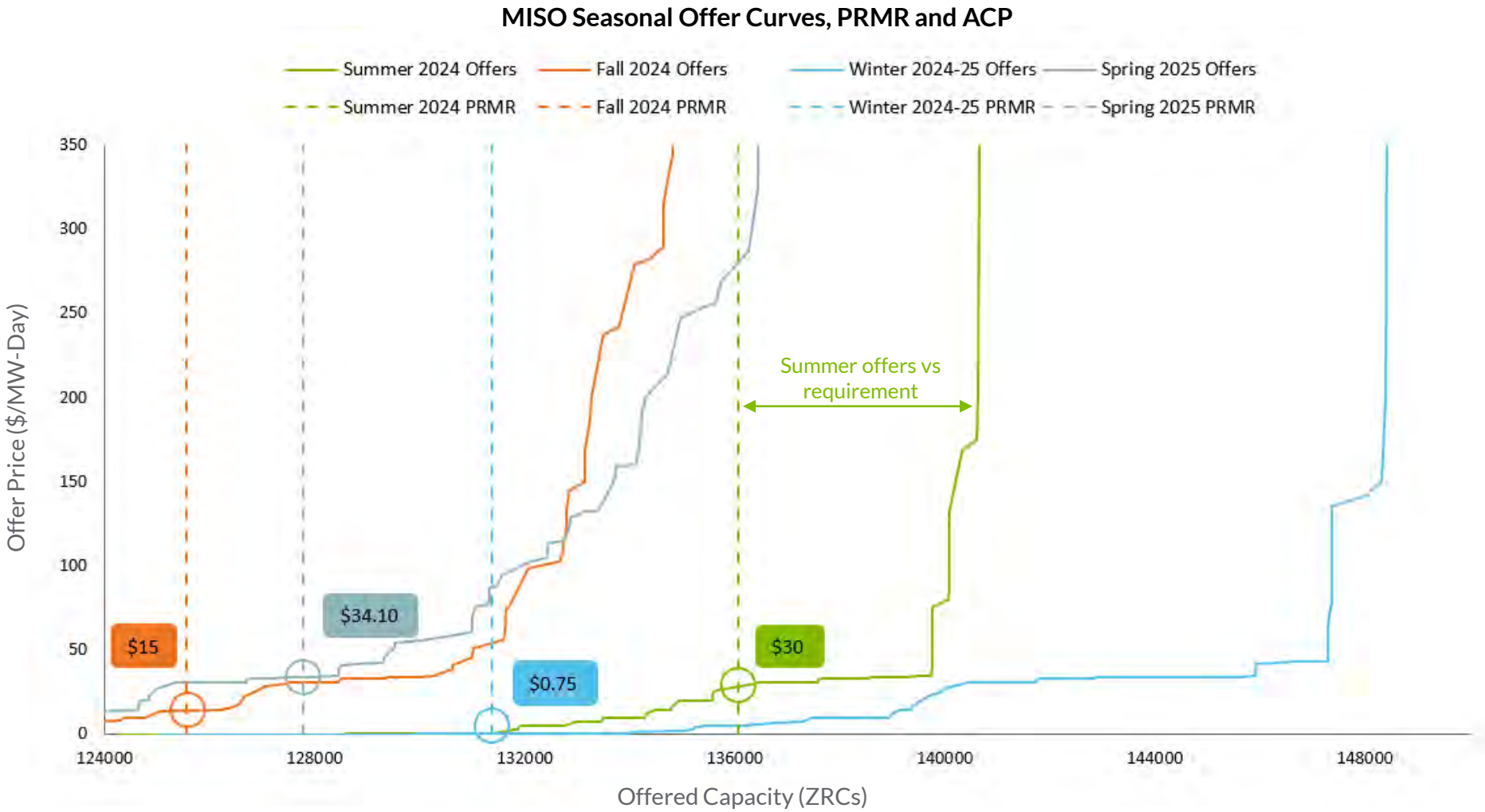
PO: Planned Outage

Seasonal variation in requirements and available capacity help explain the resource adequacy position in Zone 5



- Large coal retirements contribute to capacity deficiency; planned outages increase the gap in fall
- Lower Local Clearing Requirement in winter aids winter sufficiency
- Winter Local Clearing Requirement driven by relatively lower demand, Local Reliability Requirement and a higher import limit

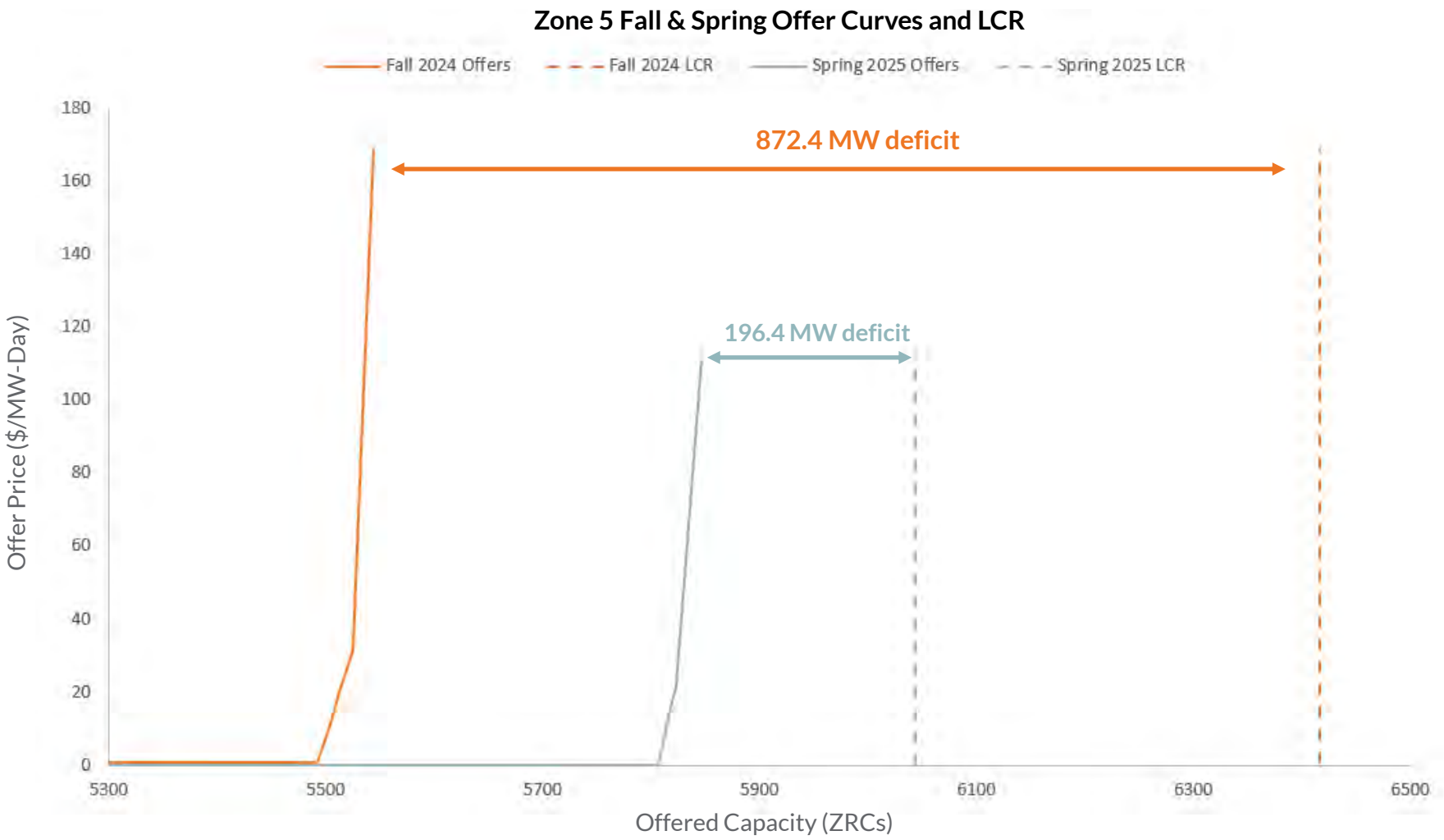
Adequate supply resulted in level auction clearing prices in each season across MISO, except for Zone 5



Y-axis truncated to provide a zoomed-in view.

PRMR: Planning Reserve Margin Requirement

Zone 5 did not have adequate capacity to meet Local Clearing Requirement in fall and spring, driving prices to seasonal CONE



Decreasing capacity surplus and the zonal deficiency, coupled with emerging risks due to fleet transition and new load additions, reinforce the urgency for ongoing reforms

Reforms under the Reliability Imperative are timely and responsive to the drivers contributing to resource adequacy challenges

DRIVERS

- Premature retirement of dispatchable resources
- Slow pace of resource additions
- Loss of accredited capacity & reliability attributes
- New load additions

MISO RESPONSE

Implemented
- Seasonal construct & thermal accreditation: implemented PY 2023-24

Filed
- Reliability-based demand curve: implementation PY 2025-26
- Resource accreditation: implementation PY 2028-29

Ongoing
- Load modifying resources accreditation: Target PY 2028-29
- Attributes roadmap and associated reforms

Next Steps

- **May 22**
  - Zonal deliverability benefits available at the May RASC
  - MISO publishes cleared Load Modifying Resources to Operations tools
- **May 24**
  - Posting of PRA masked offer data per Module E 69 A.7.4
- **June 1**
  - New Planning Year starts

Appendix

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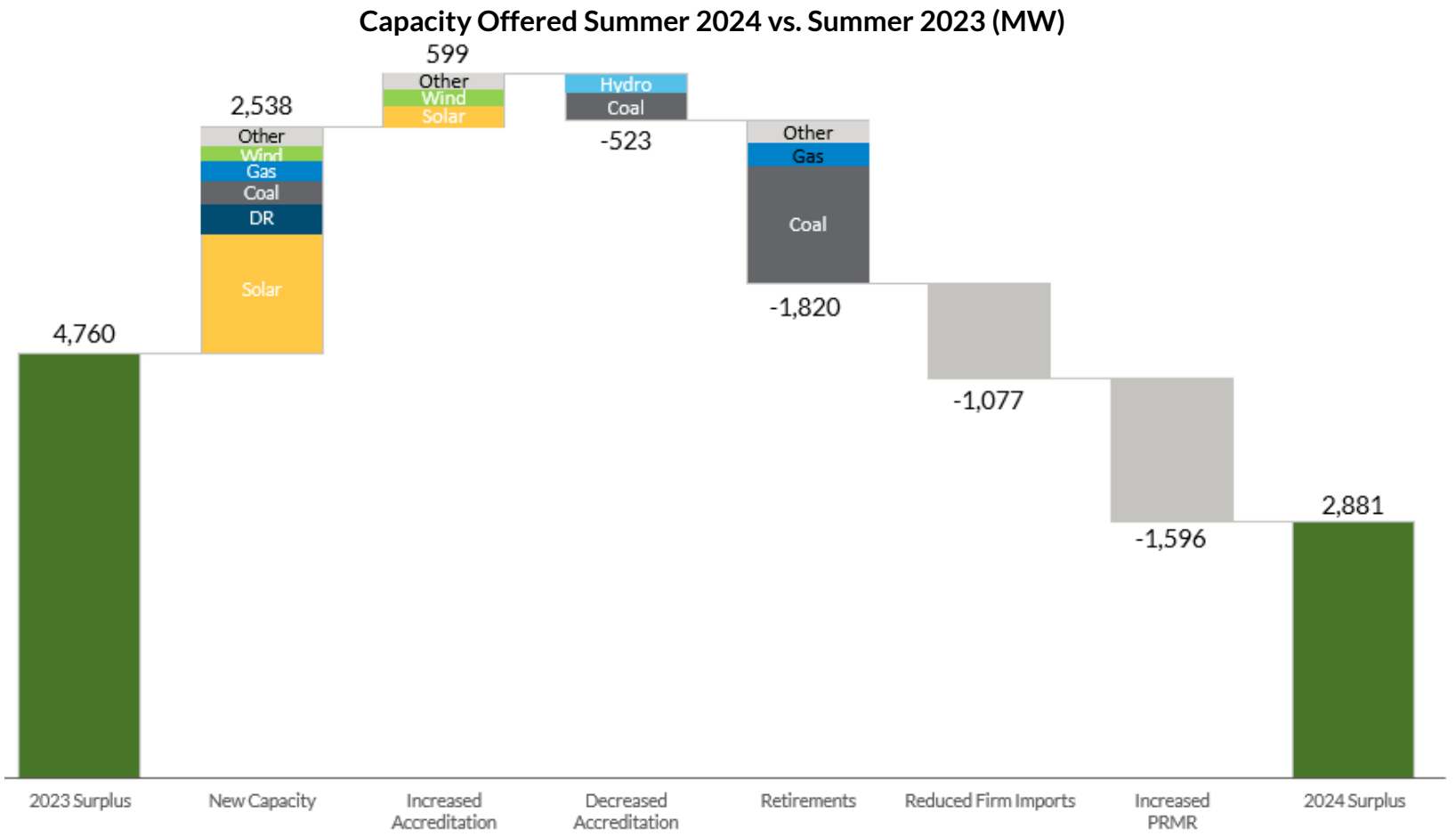
Acronyms

ACP: Auction Clearing Price
ARC: Aggregator of Retail Customers
BTMG: Behind the Meter Generator
CIL: Capacity Import Limit
CEL: Capacity Export Limit
CONE: Cost of New Entry
DR: Demand Resource
ELCC: Effective Load Carrying Capability
EE: Energy Efficiency
ER: External Resource
ERZ: External Resource Zones
FRAP: Fixed Resource Adequacy Plan
ICAP: Installed Capacity
IMM: Independent Market Monitor
LCR: Local Clearing Requirement
LMR: Load Modifying Resource
LRR: Local Reliability Requirement
LRZ: Local Resource Zone
LSE: Load Serving Entity
PO: Planned Outage
PRA: Planning Resource Auction
PRM: Planning Reserve Margin
PRMR: Planning Reserve Margin Requirement
RASC: Resource Adequacy Sub-Committee
SAC: Seasonal Accredited Capacity
SS: Self Schedule
UCAP: Unforced Capacity
ZIA: Zonal Import Ability
ZRC: Zonal Resource Credit

The North/Central region showed a 40% decrease in surplus but remained adequate

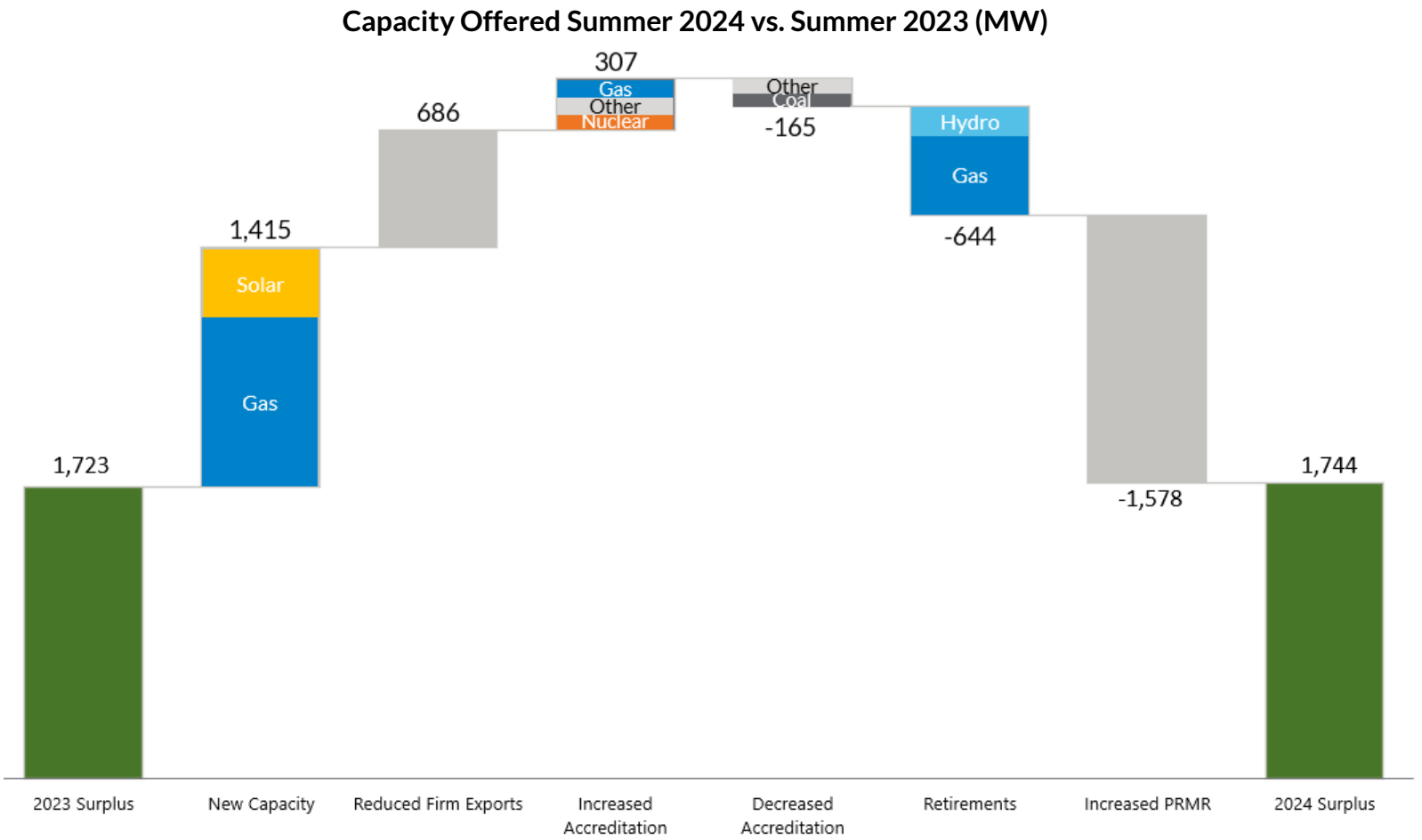
Reduced surplus driven by retirements, less imports and higher Planning Reserve Margin Requirement (PRMR)



DR: Demand Response *Capacity indicated is offered accredited value*

The South region continues to remain adequate with a comparable surplus to 2023

New generation and lower exports made up for the retirements and increased PRMR



Capacity indicated is offered accredited value

Summer 2024 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	System
PRMR	18,697	13,396	10,787	9,403	8,297	18,565	21,565	8,431	21,888	5,038	N/A	136,067
Offer Submitted (Including FRAP)	20,746	14,820	11,215	8,826	7,422	15,738	21,914	10,727	21,542	5,681	2,058	140,689
FRAP	13,961	11,216	4,248	636	0	1,109	1,352	349	166	1,616	201	34,852
Self Scheduled (SS)	4,754	3,150	6,618	5,185	7,414	9,152	20,283	9,614	18,172	3,368	1,698	89,408
Non-SS Offer Cleared	376	454	342	2,543	8	4,964	36	663	1,887	372	159	11,804
Committed (Offer Cleared + FRAP)	19,091	14,820	11,208	8,364	7,422	15,224	21,671	10,625	20,225	5,356	2,058	136,064
LCR	13,591	9,354	7,662	452	7,014	12,788	19,271	7,523	18,380	3,652	-	N/A
CIL	6,462	4,506	4,969	10,749	3,208	7,481	4,500	3,608	5,305	3,564	-	N/A
ZIA	6,460	4,506	4,911	9,857	3,208	7,197	4,490	3,444	4,794	3,564	-	N/A
Import	0	0	0	1,039	875	3,340	0	0	1,663	0	-	6,917
CEL	4,357	3,971	5,490	2,771	4,644	5,619	5,709	6,099	3,025	1,840	-	N/A
Export	394	1,424	421	0	0	0	107	2,195	0	318	2,058	6,917
ACP ($/MW-Day)	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	N/A

Values displayed in MW SAC

Fall 2024 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	System
PRMR	16,254	12,001	9,944	8,715	7,970	17,770	19,893	7,602	20,653	4,750	N/A	125,552
Offer Submitted (Including FRAP)	19,802	14,551	10,818	8,437	5,544	15,443	21,019	10,293	20,808	5,773	2,392	134,879
FRAP	11,904	10,092	3,411	547	0	918	1,240	340	151	1,531	208	30,341
Self Scheduled (SS)	4,670	2,590	6,095	6,109	5,492	7,625	19,165	8,990	17,167	3,444	1,677	83,023
Non-SS Offer Cleared	820	187	1,195	1,606	52	5,108	286	300	1,795	707	132	12,188
Committed (Offer Cleared + FRAP)	17,394	12,870	10,701	8,262	5,544	13,651	20,691	9,629	19,112	5,681	2,016	125,551
LCR	12,337	7,152	5,281	3,674	6,416	10,750	19,443	5,499	16,631	2,482	-	N/A
CIL	6,502	5,719	6,746	6,594	3,786	8,959	4,400	5,137	6,109	4,736	-	N/A
ZIA	6,500	5,719	6,684	5,699	3,786	8,661	4,390	4,942	5,608	4,736	-	N/A
Import	0	0	0	453	2,426	4,119	0	0	1,541	0	-	8,539
CEL	5,711	4,512	6,956	3,906	5,402	3,514	5,381	4,115	2,803	2,889	-	N/A
Export	1,140	868	757	0	0	0	799	2,027	0	931	2,016	8,539
ACP ($/MW-Day)	15.00	15.00	15.00	15.00	719.81	15.00	15.00	15.00	15.00	15.00	15.00	N/A

Values displayed in MW SAC

Winter 2024/2025 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	System
PRMR	18,528	11,704	10,628	9,300	8,375	19,180	17,366	8,977	22,194	5,127	N/A	131,377
Offer Submitted (Including FRAP)	23,738	14,545	15,243	8,097	5,986	15,888	23,032	10,121	22,877	6,338	2,575	148,438
FRAP	12,907	9,576	4,630	667	0	975	1,161	357	152	1,987	178	32,591
Self Scheduled (SS)	6,780	3,119	7,726	5,690	5,963	9,163	19,620	9,754	18,763	3,903	1,978	92,459
Non-SS Offer Cleared	0	0	484	1,563	0	2,341	55	1	1,866	7	10	6,327
Committed (Offer Cleared + FRAP)	19,687	12,695	12,840	7,920	5,963	12,479	20,836	10,112	20,782	5,897	2,167	131,377
LCR	16,972	7,189	10,804	3,133	4,062	10,219	17,597	7,379	18,888	4,809	-	N/A
CIL	4,693	5,523	5,668	6,707	4,477	8,532	4,656	4,364	5,200	3,219	-	N/A
ZIA	4,691	5,523	5,600	5,811	4,477	8,286	4,656	4,262	4,623	3,219	-	N/A
Import	0	0	0	1,380	2,412	6,701	0	0	1,412	0	-	11,905
CEL	5,174	4,772	9,011	4,674	6,229	1,401	5,753	5,780	2,323	2,993	-	N/A
Export	1,159	992	2,212	0	0	0	3,471	1,135	0	770	2,167	11,905
ACP ($/MW-Day)	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	N/A

Values displayed in MW SAC

Spring 2025 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	System
PRMR	17,217	12,183	9,992	7,981	7,711	17,847	19,670	7,891	22,066	5,234	N/A	127,792
Offer Submitted (Including FRAP)	19,201	14,896	10,946	8,654	5,847	15,173	21,218	11,029	21,026	6,144	2,480	136,615
FRAP	12,319	9,949	3,950	638	0	1,039	1,256	329	152	1,559	197	31,387
Self Scheduled (SS)	4,226	3,458	6,220	5,790	5,806	7,979	18,316	9,504	15,711	3,387	1,823	82,219
Non-SS Offer Cleared	783	801	166	1,751	41	5,374	390	687	2,959	849	385	14,185
Committed (Offer Cleared + FRAP)	17,328	14,208	10,335	8,178	5,847	14,393	19,961	10,520	18,822	5,794	2,404	127,791
LCR	13,945	8,370	5,781	4,560	6,044	11,386	16,372	4,413	18,684	3,558	-	N/A
CIL	4,943	5,034	6,572	6,982	3,892	8,045	4,883	6,195	6,113	4,628	-	N/A
ZIA	4,941	5,034	6,514	5,083	3,892	7,730	4,883	6,030	5,598	4,628	-	N/A
Import	0	0	0	0	1,864	3,454	0	0	3,244	0	-	8,562
CEL	6,318	4,601	5,815	5,102	4,984	3,414	5,601	4,865	4,298	2,740	-	N/A
Export	111	2,025	344	197	0	0	291	2,629	0	561	2,404	8,562
ACP ($/MW-Day)	34.10	34.10	34.10	34.10	719.81	34.10	34.10	34.10	34.10	34.10	34.10	N/A

Values displayed in MW SAC

Summer Supply Offered and Cleared Comparison Trend

	Offered (ZRC)			Cleared (ZRC)		
Planning Resource	2022-23	Summer 2023	Summer 2024	2022-23	Summer 2023	Summer 2024
Generation	121,506.5	122,375.6	123,395.6	118,745.0	116,989.7	119,479.2
External Resources	3,563.9	4,514.6	4,430.4	3,563.9	4,072.5	4,309.8
Behind the Meter Generation	4,169.3	4,175.2	4,180.2	4,169.3	4,129.4	4,143.5
Demand Resources	7,574.9	8,303.5	8,660.2	7,525.0	7,694.6	8,109.4
Energy Efficiency	0.0	5.0	22.5	0.0	5.0	22.5
Total	**136,814.6**	**139,373.9**	**140,688.9**	**134,003.2**	**132,891.2**	**136,064.4**

Fall Supply Offered and Cleared Comparison Trend

	Offered (ZRC)		Cleared (ZRC)	
Planning Resource	Fall 2023	Fall 2024	Fall 2023	Fall 2024
Generation	121,403.5	119,745.3	111,713.8	111,791.5
External Resources	4,095.4	4,366.8	3,979.6	3,990.2
Behind the Meter Generation	3,874.2	3,877.9	3,842.8	3,789.7
Demand Resources	6,999.2	6,866.1	6,254.4	5,957.5
Energy Efficiency	4.9	22.5	4.8	22.5
Total	**136,377.2**	**134,878.6**	**125,795.4**	**125,551.4**

Winter Supply Offered and Cleared Comparison Trend

	Offered (ZRC)		Cleared (ZRC)	
Planning Resource	Winter 2023-2024	Winter 2024-2025	Winter 2023-2024	Winter 2024-2025
Generation	124,632.7	133,457.4	114,886.6	118,253.8
External Resources	3,937.1	3,973.0	3,334.6	3,313.3
Behind the Meter Generation	3,257.8	3,111.5	3,173.9	2,957.3
Demand Resources	7,644.4	7,866.4	6,702.4	6,822.7
Energy Efficiency	6.7	29.7	6.7	29.7
Total	**139,478.7**	**148,438.0**	**128,104.2**	**131,376.8**

Spring Supply Offered and Cleared Comparison Trend

	Offered (ZRC)		Cleared (ZRC)	
Planning Resource	Spring 2024	Spring 2025	Spring 2024	Spring 2025
Generation	119,254.7	121,303.8	110,195.8	113,091.4
External Resources	3,794.1	3,481.8	3,409.1	3,406.5
Behind the Meter Generation	4,096.4	4,201.6	4,058.9	4,180.5
Demand Resources	7,282.9	7602.9	6,720.0	7,087.2
Energy Efficiency	5.3	25.0	5.3	25.0
Total	**134,433.4**	**136,615.1**	**124,389.1**	**127,790.6**

Zone 5 Supply Offered and Cleared Comparison Trend

	Offered (ZRC)				Cleared (ZRC)			
Planning Resource	Summer 2024	Fall 2024	Winter 2024-2025	Spring 2025	Summer 2024	Fall 2024	Winter 2024-2025	Spring 2025
Generation	7,139.9	5,414.3	5,864.9	5,695.9	7,139.9	5,414.3	5,850.2	5,695.9
Behind the Meter Generation	79.9	78.5	77.1	84.0	79.9	78.5	77.1	84.0
Demand Resources	202.5	51.2	43.8	67.2	202.5	51.2	35.3	67.2
Energy Efficiency	0	0	0	0	0	0	0	0
Imports (External & Imports from other zones)	874.7	2,425.8	2,411.9	1,864.1	874.7	2,425.8	2,411.9	1,864.1
Total	**8,297.0**	**7,969.8**	**8,397.7**	**7,711.2**	**8,297.0**	**7,969.8**	**8,374.5**	**7,711.2**

Historical Summer Auction Clearing Price Comparison

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
2015-2016	$3.48			$150.00	$3.48			$3.29		N/A	N/A
2016-2017	$19.72	$72.00						$2.99			N/A
2017-2018	$1.50										N/A
2018-2019	$1.00	$10.00									N/A
2019-2020	$2.99						$24.30	$2.99			
2020-2021	$5.00						$257.53	$4.75	$6.88	$4.75	$4.89-$5.00
2021-2022	$5.00							$0.01			$2.78-$5.00
2022-2023	$236.66							$2.88			$2.88-236.66
Summer 2023	$10.00										
Summer 2024	$30.00										

- Auction Clearing Prices shown in $/MW-Day
- Conduct Threshold is 10% of Cost of New Entry (CONE) and applies to all seasons.

Fall Auction Clearing Price Comparison

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
Fall 2023	$15.00								$59.21	$15.00	
Fall 2024	$15.00				$719.81	$15.00					
IMM Conduct Threshold	34.12	33.35	32.22	33.27	36.09	32.97	34.83	31.18	30.91	30.76	36.09
Cost of New Entry (Daily)	341.21	333.51	322.19	332.70	360.89	329.70	348.32	311.81	309.05	307.57	360.89
Cost of New Entry (Annual)	124,541	121, 731	117,600	121,434	131,725	120,340	127,135	113,810	112,804	112,263	131,725

- There was price separation in the fall for Zone 5 since it did not have sufficient supply within the zone to meet its local clearing requirement
- Auction Clearing Prices shown in $/MW-Day
- Conduct Threshold is 10% of Daily Cost of New Entry (CONE) and applies to all seasons
- For Zone 5, there were 183 shortage-days (fall and spring); ACP is Annual CONE / # of shortage-days: 131,725 / 183 = $719.81

Winter Auction Clearing Price Comparison

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
Winter 2023-24	$2.00								$18.88	$2.00	
Winter 2024-25	$0.75										

- Auction Clearing Prices shown in $/MW-Day
- Conduct Threshold is 10% of Cost of New Entry (CONE) and applies to all seasons

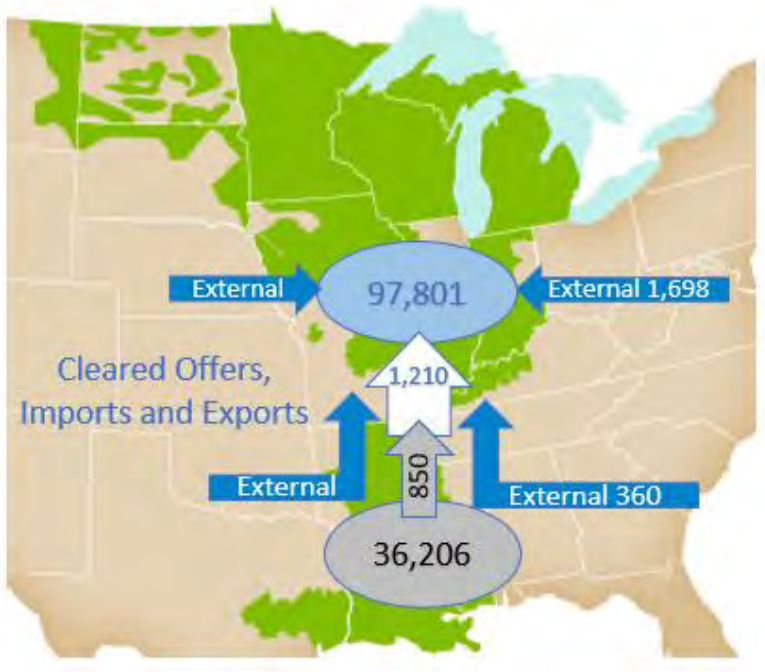
Spring Auction Clearing Price Comparison

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
Spring 2024	$10.00										
Spring 2025	$34.10				$719.81	$34.10					

- There was price separation in the Spring for Zone 5 since it did not have sufficient supply within the zone to meet its local clearing requirement
- Auction Clearing Prices shown in $/MW-Day
- Conduct Threshold is 10% of Cost of New Entry (CONE) and applies to all seasons

Summer 2024
Offered Capacity & PRMR (MW)

Summer 2024
Cleared Capacity, Imports & Exports (MW)

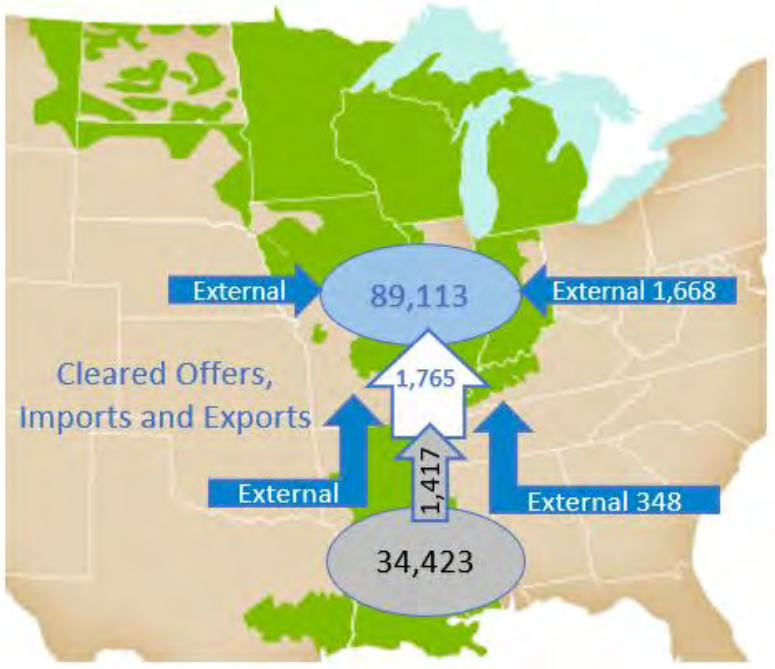


PRMR: Planning Reserve Margin Requirement
Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers

04/26/2024: MISO Planning Resource Auction (PRA) for Planning Year 2024-2025 Results Posting

Fall 2024
Offered Capacity & PRMR (MW)

Fall 2024
Cleared Capacity, Imports & Exports (MW)



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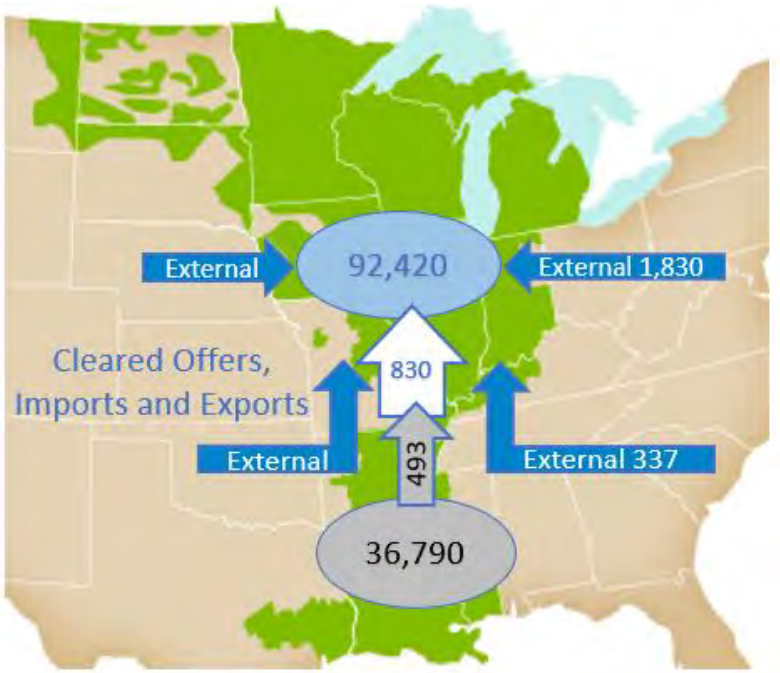
04/26/2024: MISO Planning Resource Auction (PRA) for Planning Year 2024-2025 Results Posting

Winter 2024/25
Offered Capacity & PRMR (MW)

Winter 2024/25
Cleared Capacity, Imports & Exports (MW)



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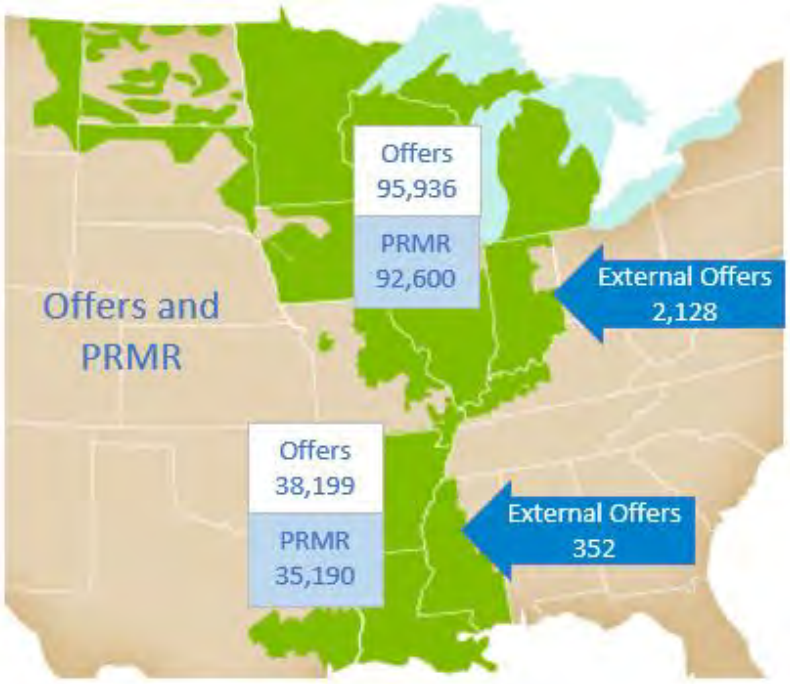
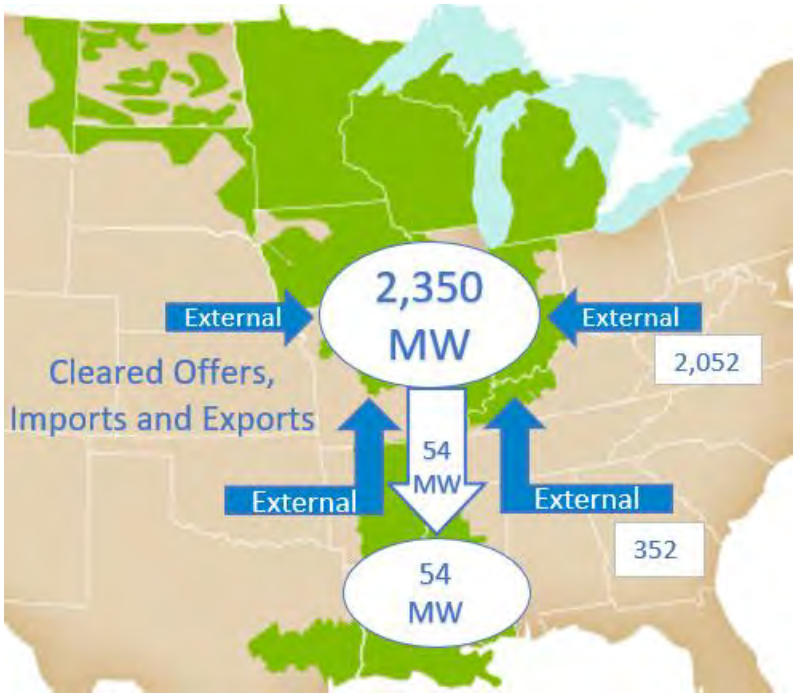
Spring 2025
Offered Capacity & PRMR (MW)



Spring 2025
Cleared Capacity, Imports & Exports (MW)



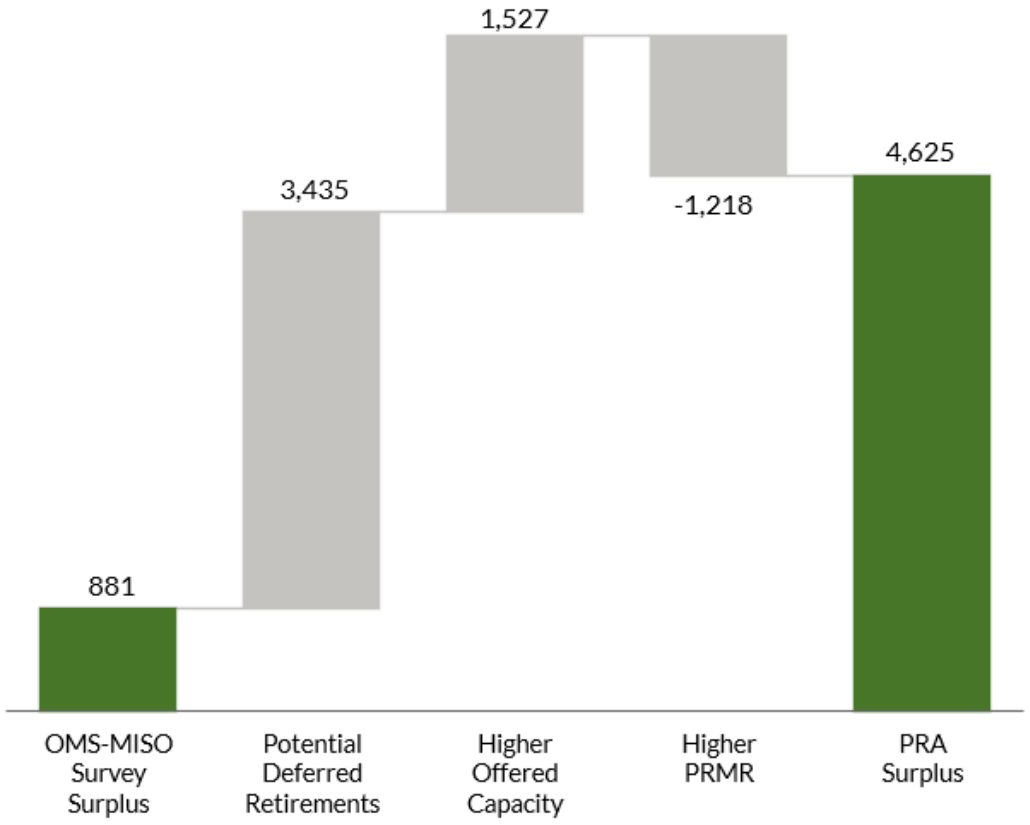
PRMR: Planning Reserve Margin Requirement
Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers

04/26/2024: MISO Planning Resource Auction (PRA) for Planning Year 2024-2025 Results Posting

2024 PRA showed a higher surplus relative to the 2023 OMS-MISO survey projection, driven primarily by deferred retirements

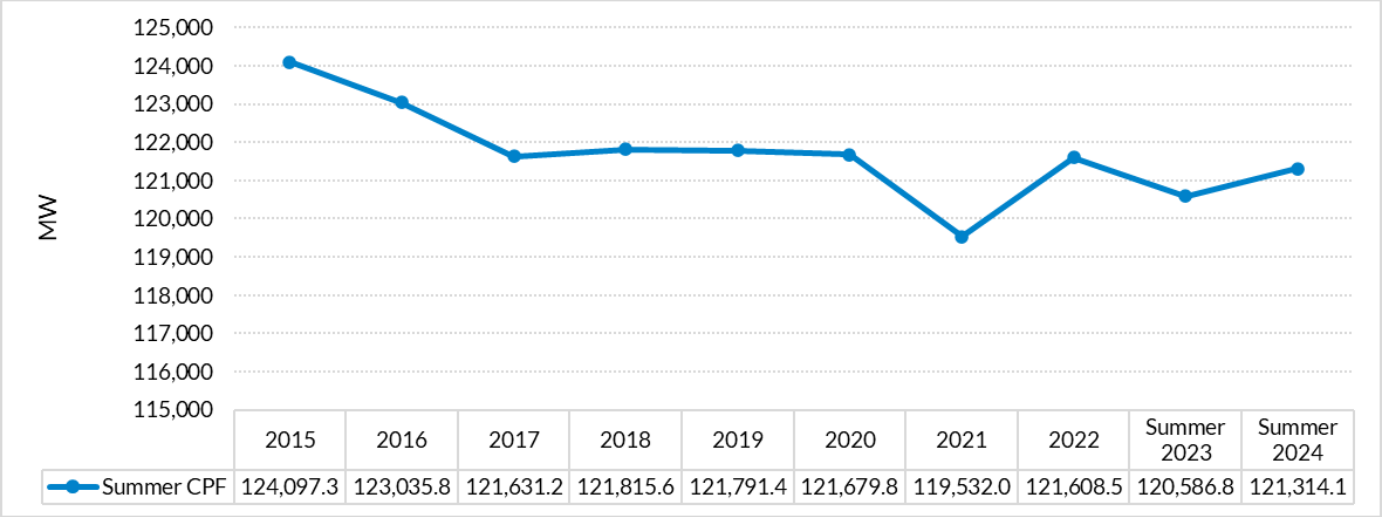
Summer 2024 PRA outcomes vs. 2023 OMS-Survey results

- 3.4 of the 3.5 GW of potential deferred retirement participated in the PRA
- Resources offered in the PRA at 1.5 GW higher than projected in the OMS-MISO Survey
- 1.2 GW higher PRMR MISO-wide because of a higher PRM % than forecasted in the 2023 survey (9% versus 7.9%)

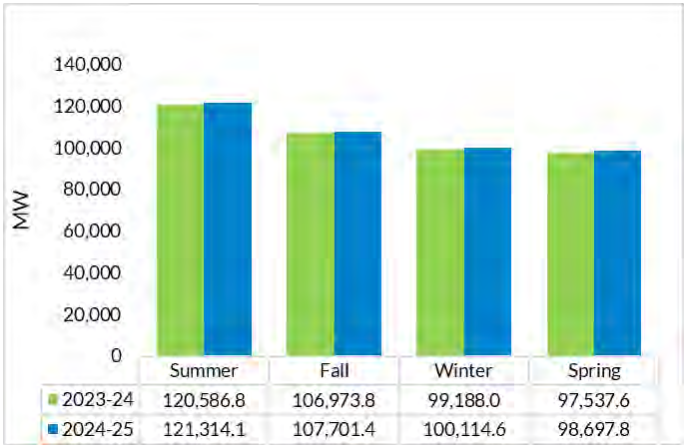


Coincident Peak Forecast

Year over year the Summer CPF (+0.7 GW), PRM (+1.6%) and PRMR (+3.2 GW) are higher.

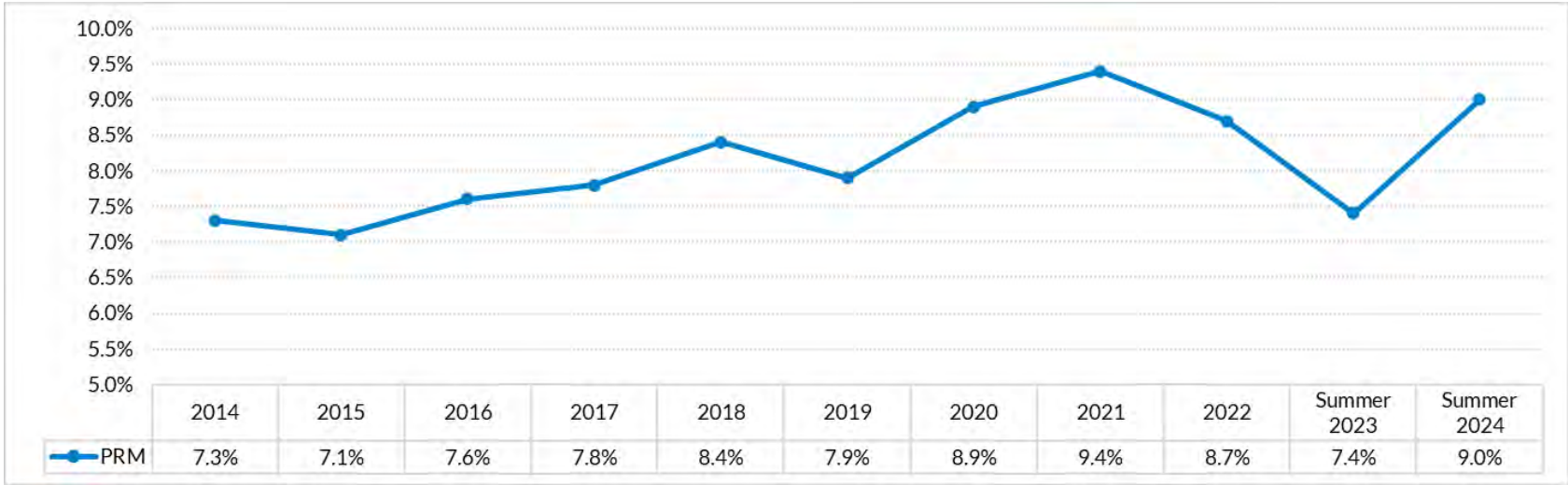


	2015	2016	2017	2018	2019	2020	2021	2022	Summer 2023	Summer 2024
Summer CPF	124,097.3	123,035.8	121,631.2	121,815.6	121,791.4	121,679.8	119,532.0	121,608.5	120,586.8	121,314.1

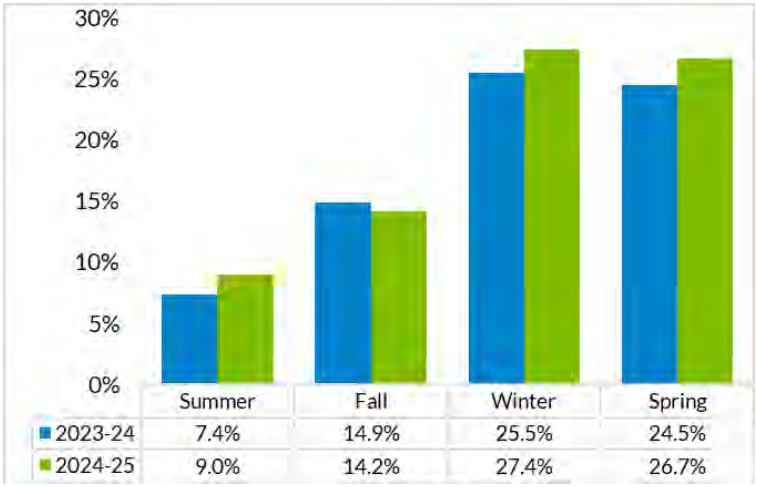


	Summer	Fall	Winter	Spring
2023-24	120,586.8	106,973.8	99,188.0	97,537.6
2024-25	121,314.1	107,701.4	100,114.6	98,697.8

Planning Reserve Margin (%)

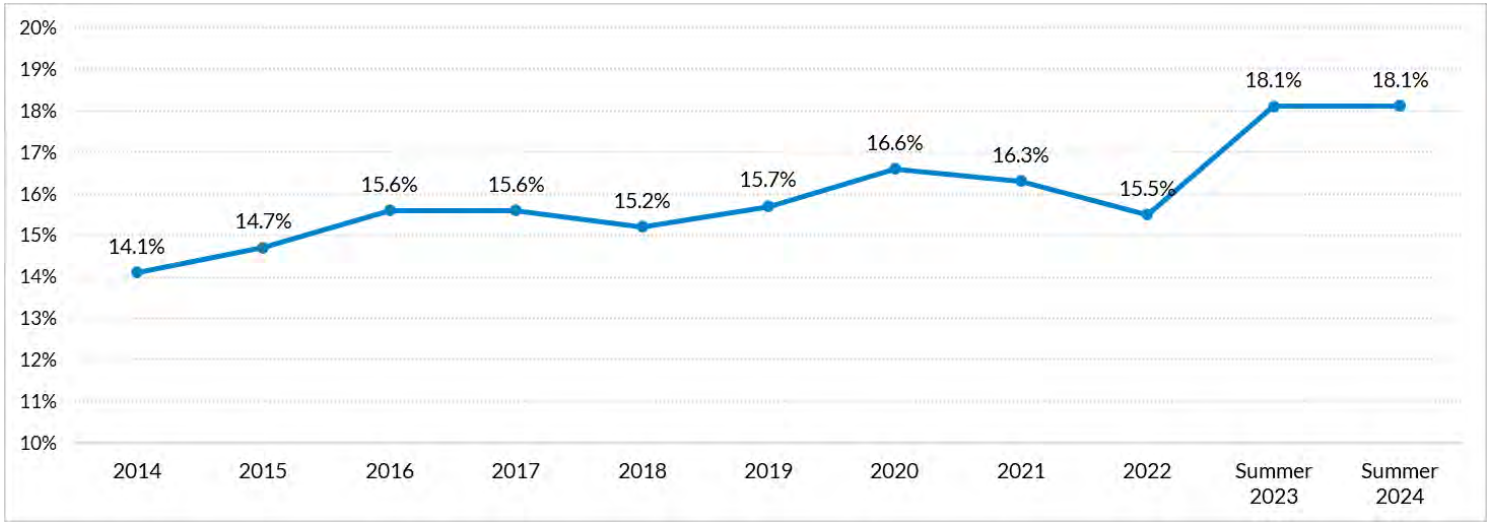


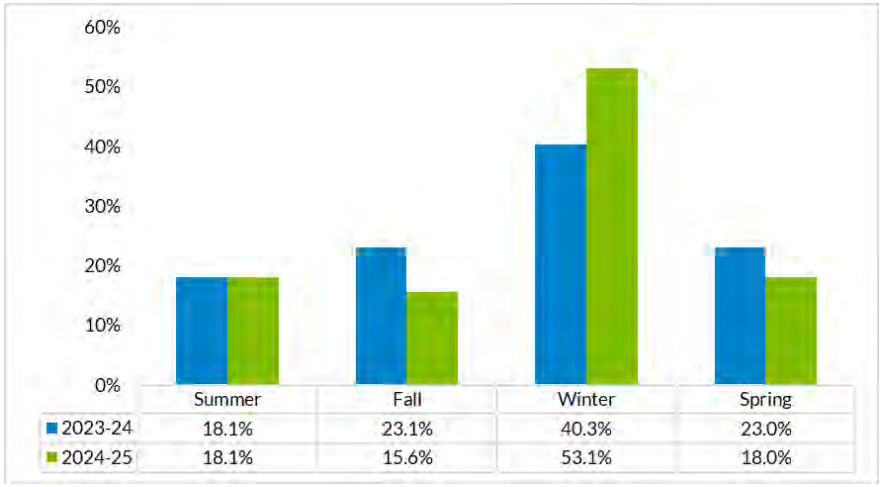
	2014	2015	2016	2017	2018	2019	2020	2021	2022	Summer 2023	Summer 2024
PRM	7.3%	7.1%	7.6%	7.8%	8.4%	7.9%	8.9%	9.4%	8.7%	7.4%	9.0%



	Summer	Fall	Winter	Spring
2023-24	7.4%	14.9%	25.5%	24.5%
2024-25	9.0%	14.2%	27.4%	26.7%

Wind Effective Load Carrying Capacity (%)



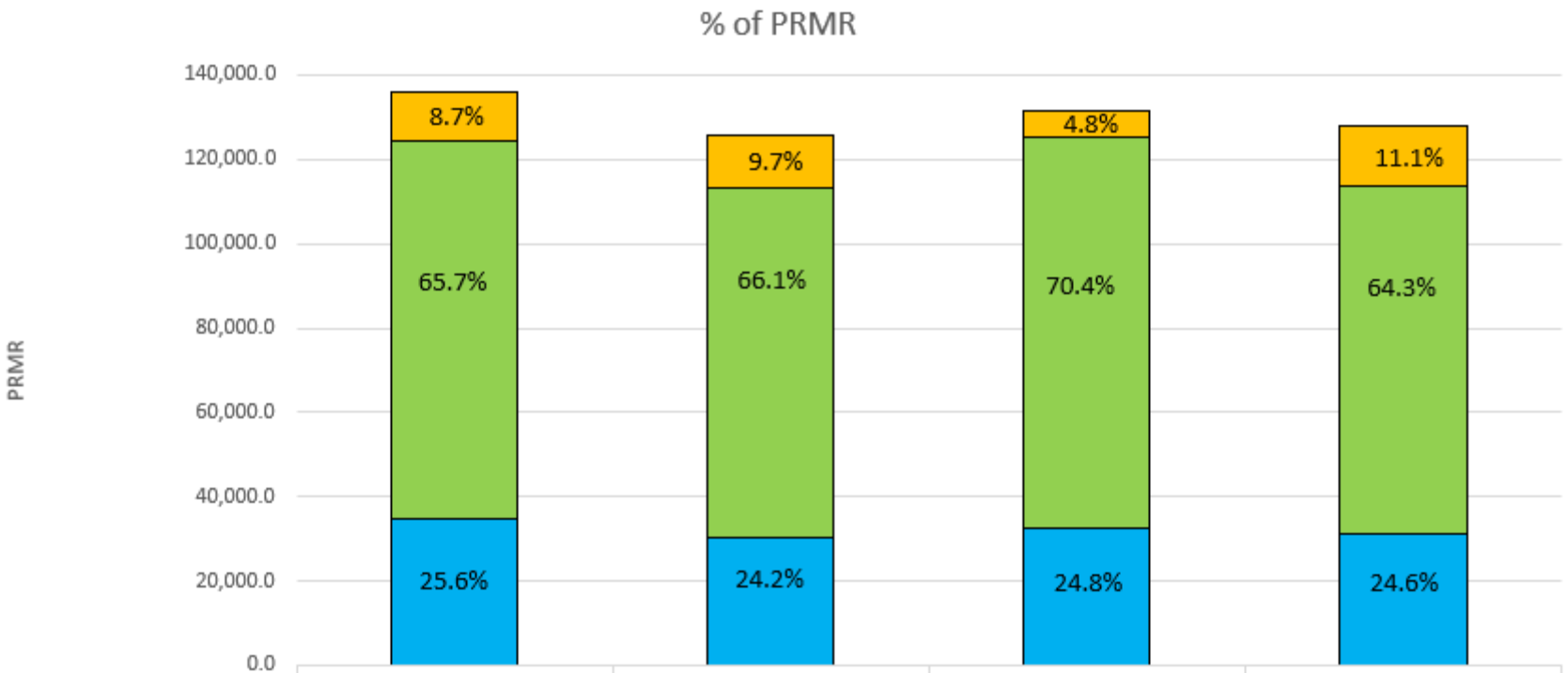


	Summer	Fall	Winter	Spring
2023-24	18.1%	23.1%	40.3%	23.0%
2024-25	18.1%	15.6%	53.1%	18.0%

- No change to wind or solar accreditation methodology from previous years.
- Methodology applied on a seasonal basis.
- Wind ELCC and new solar capacity is established in the LOLE Study
- New solar
  - summer, fall, spring 50%
  - winter 5%

ELCC: Effective Load Carrying Capability LOLE: Loss of Load Expectation

2024-2025 Seasonal Resource Adequacy Requirements are fulfilled similarly across all four seasons

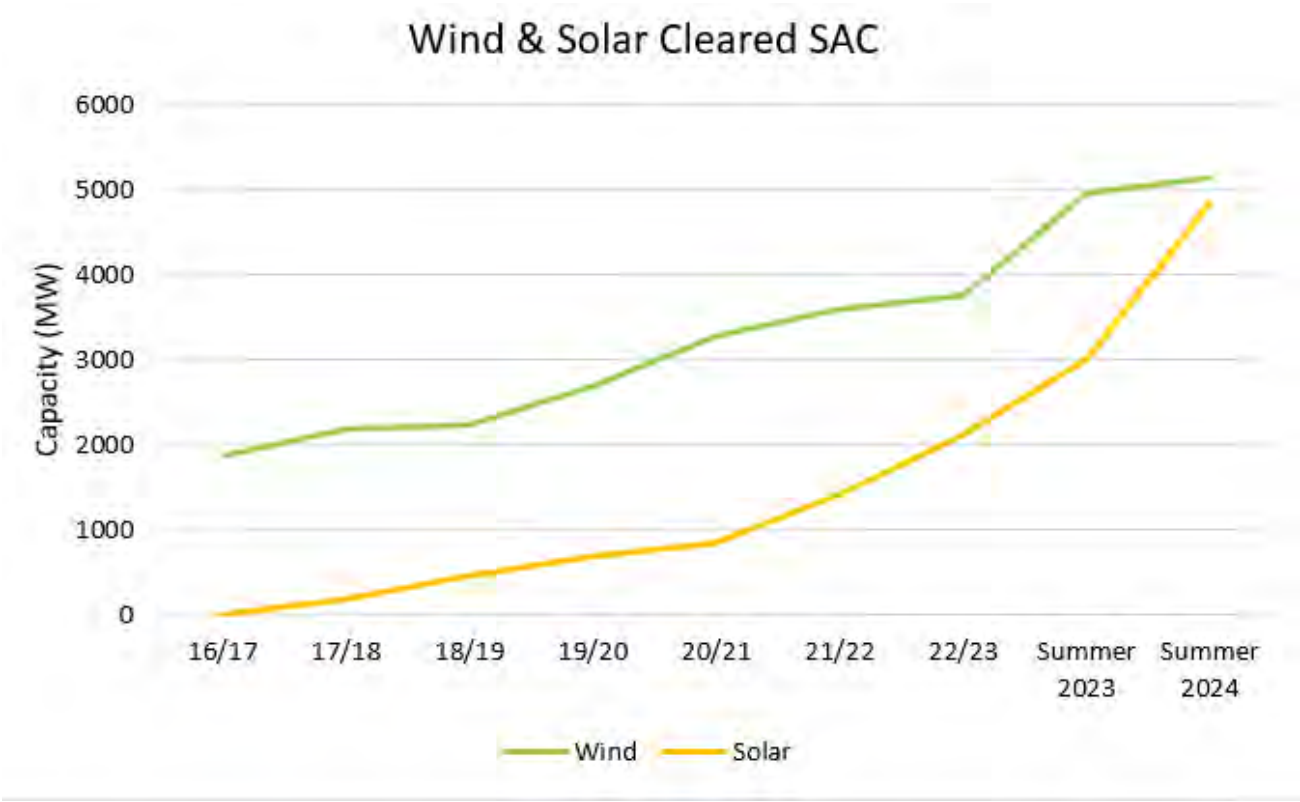


	Summer 2024	Fall 2024	Winter 2024-25	Spring 2025
Cleared Non-Self Scheduled	11,800.8	12,184.1	6,323.9	14,181.5
Self Scheduled	89,408.1	83,023.4	92,459.0	82,219.3
FRAP	34,855.5	30,343.9	32,593.9	31,389.8

PRMR: Planning Reserve Margin Requirement

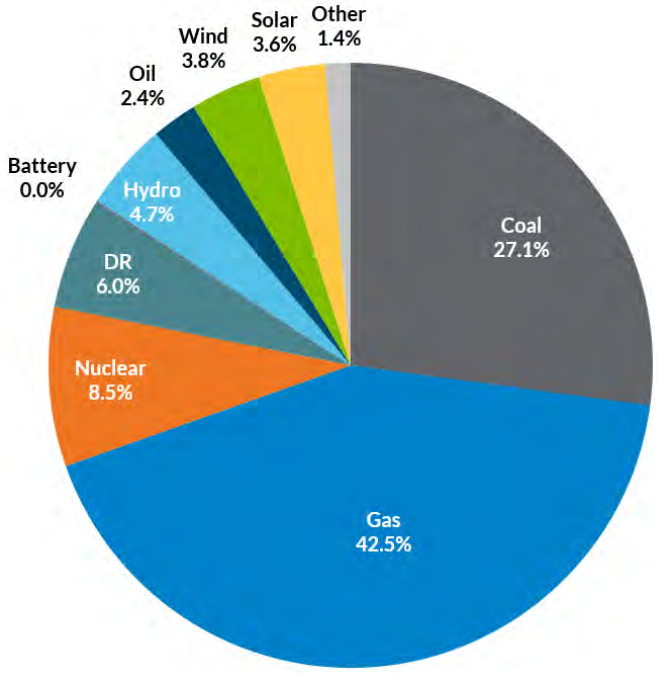
Although conventional generation still comprises most of the capacity, wind and solar continue to grow

- 4.9 GW of solar cleared this year's auction, an increase of 61% from Planning Year 2023-24 (3.0 GW)
- 5.2 GW of wind cleared this year, an increase of 4% compared to last year (5.0 GW)



Winter PRMR is 4.7 GW (3.4%) lower than the summer. There were less thermal, hydro and solar resources and significantly more wind to meet PRMR in the Winter versus the Summer

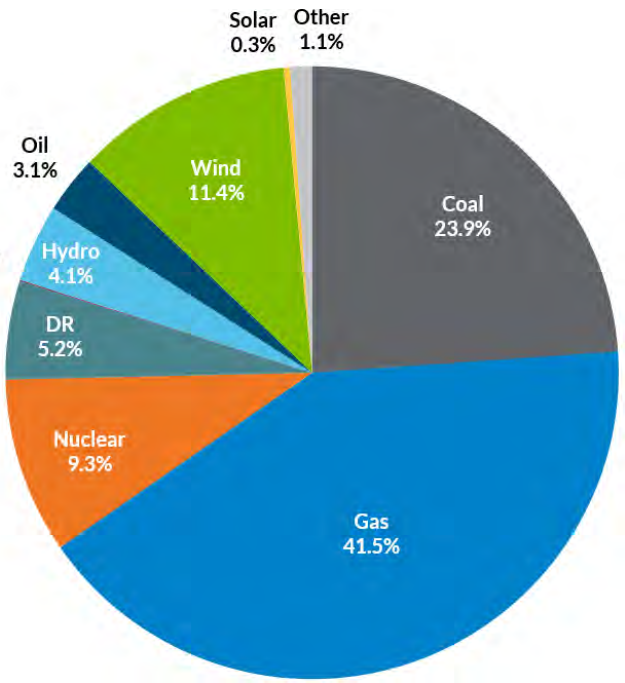
Summer 2024



MISO-wide

Cleared ZRC	Summer 2024	Winter 2024-25	Difference
Coal	36,894.8	31,391.7	5,503.1
Gas	57,799.3	54,460.7	3,338.6
Nuclear	11,594.6	12,218.0	-623.4
DR	8,109.4	6,822.7	1,286.7
Battery	59.0	59.1	-0.1
EE	22.5	29.7	-7.2
Hydro	6,427.1	5,398.9	1,028.2
Oil	3,316.6	4,010.9	-694.3
Wind	5,150.0	15,034.7	-9,884.7
Solar	4,851.7	445.0	4,406.7
Misc	1,839.4	1,505.4	334.0
PRMR	136,064.4	131,376.8	4,687.6

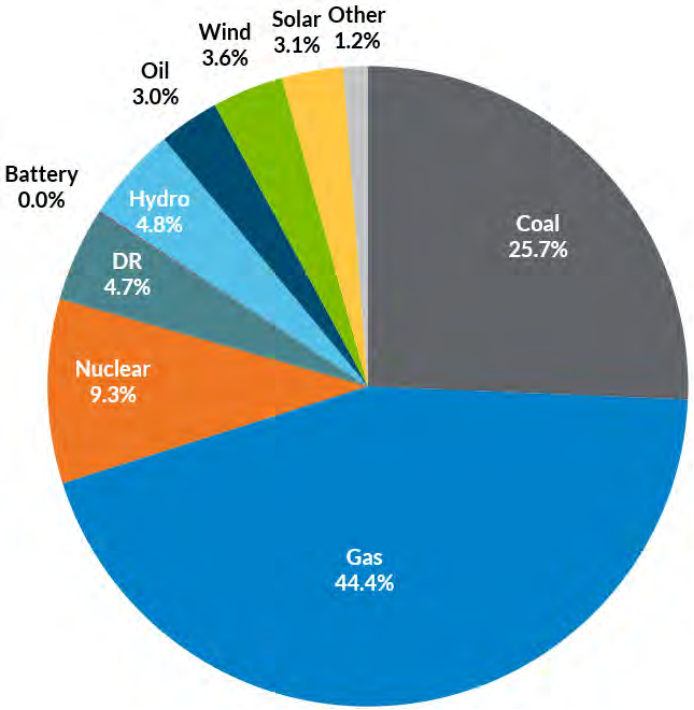
Winter 2024-25



PRMR: Planning Reserve Margin Requirement

Fall 2024 and Spring 2025 - Cleared ZRCs and PRMR

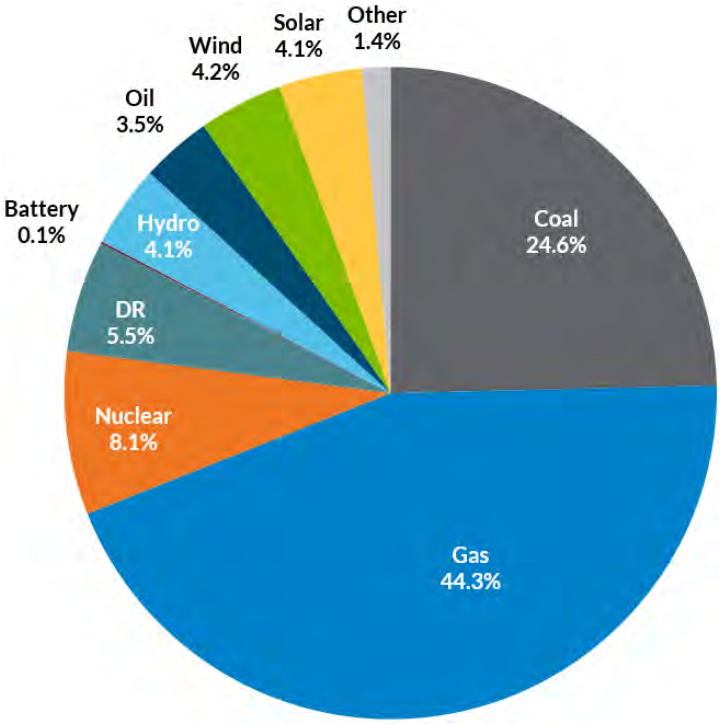
Fall 2024



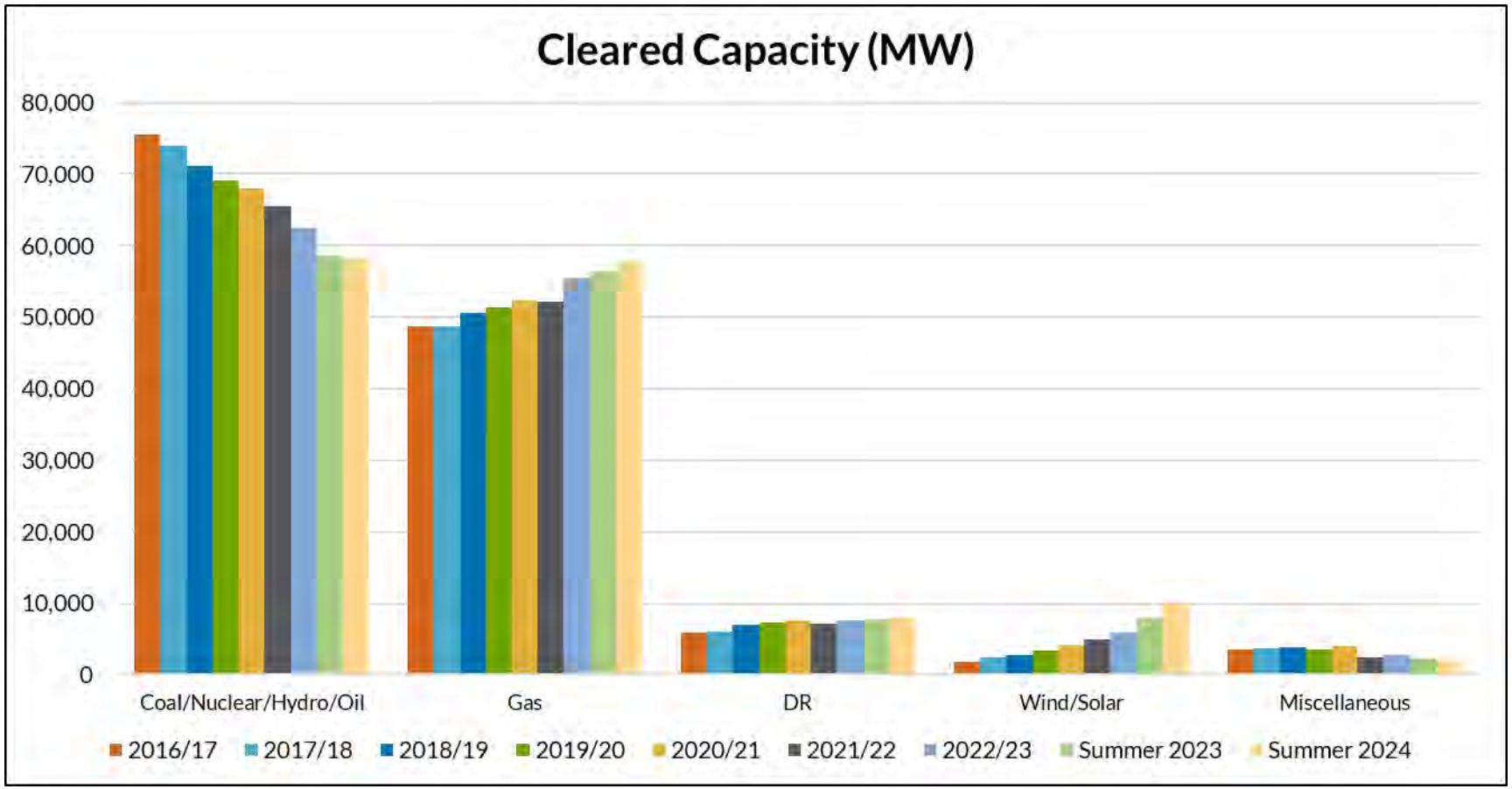
MISO-Wide

Cleared ZRC	Fall 2024	Spring 2025
Coal	32,221.7	31,469.1
Gas	55,793.3	56,667.0
Nuclear	11,682.3	10,338.7
DR	5,957.5	7,087.2
Battery	58.8	112.3
EE	22.5	25.0
Hydro	6,037.8	5,215.6
Oil	3,819.2	4,464.0
Wind	4,521.8	5,322.7
Solar	3,894.4	5,282.1
Misc	1,542.1	1,807.0
PRMR	125,551.4	127,790.6

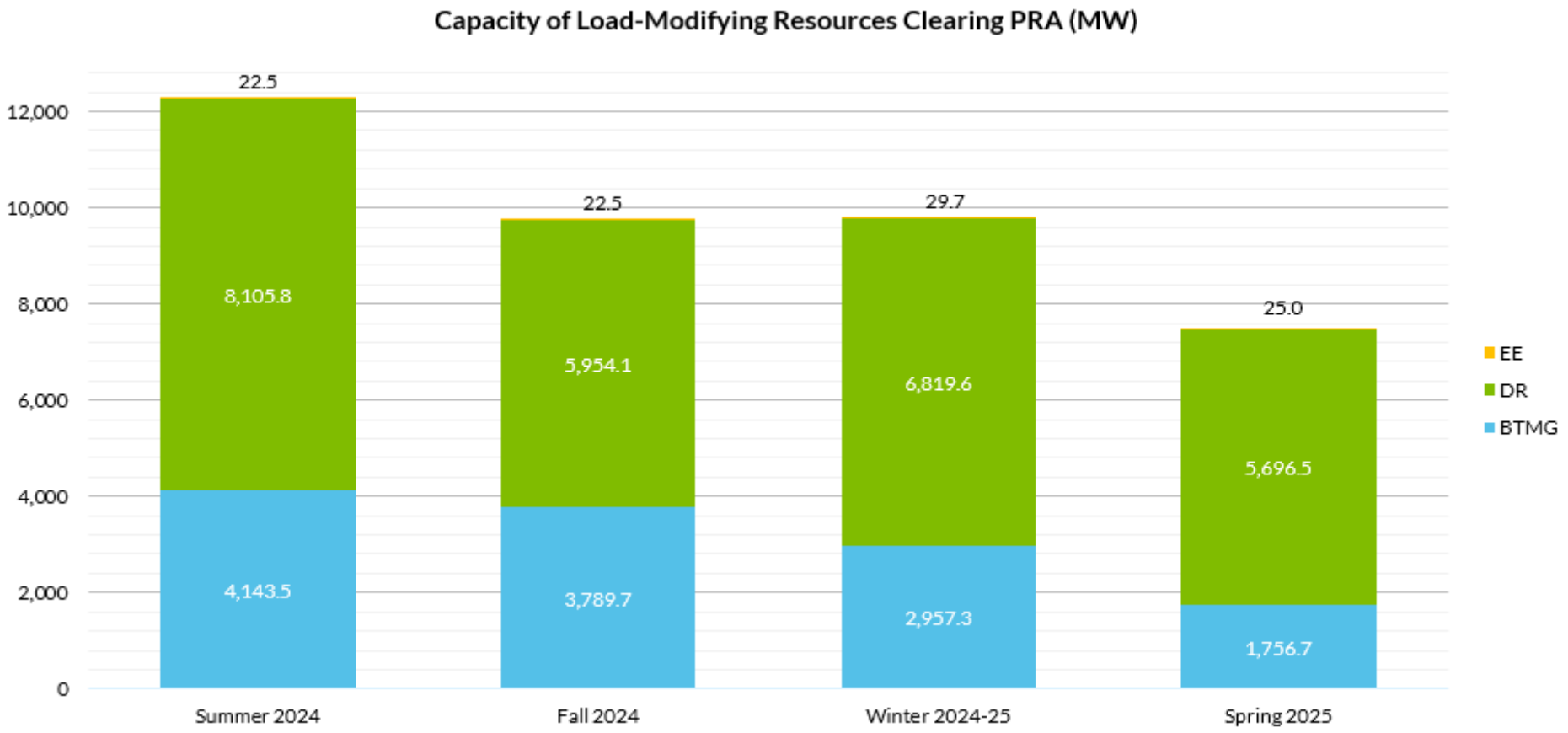
Spring 2025



The planning resource mix shows the continuation of a multi-year trend towards less coal/nuclear/hydro/oil and increased gas and non-conventional resources

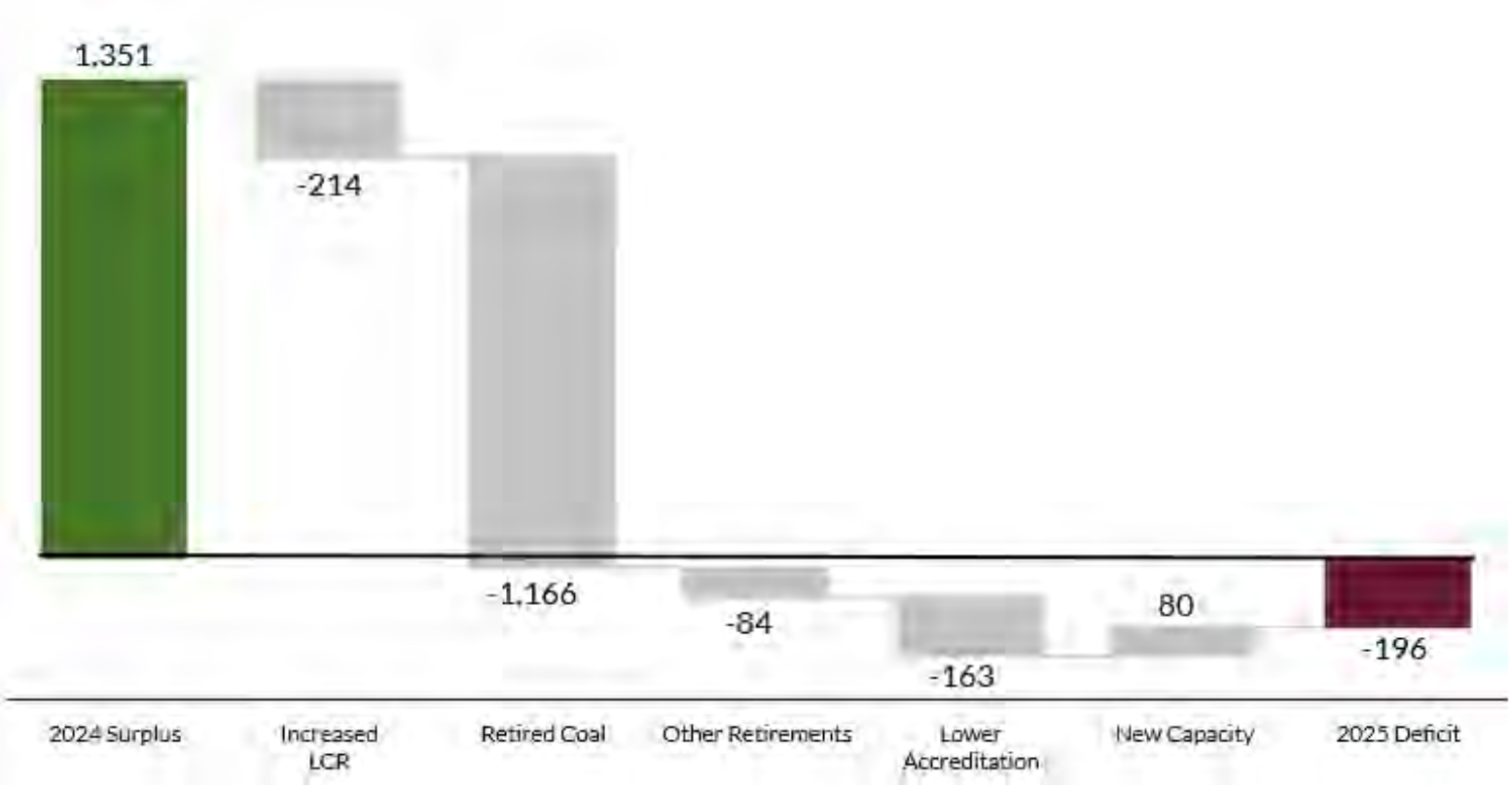


2024-2025 Seasonally Cleared Load Modifying Resources Comparison



A combination of higher Local Clearing Requirement and reduced capacity contributed to Zone 5 deficiency in the spring

Zone 5 Spring 2025 Capacity Changes Year-Over-Year



PO: Planned Outage

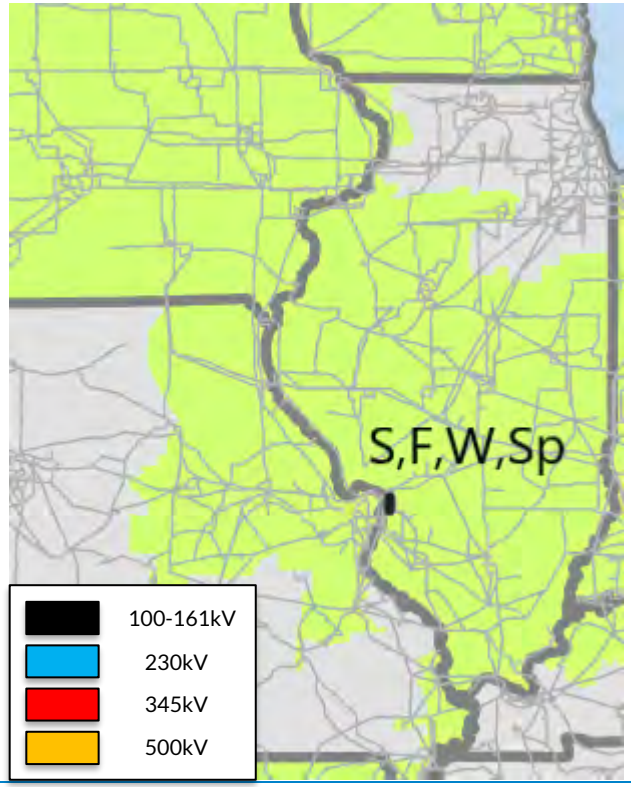
Zone 5 Local Clearing Requirement

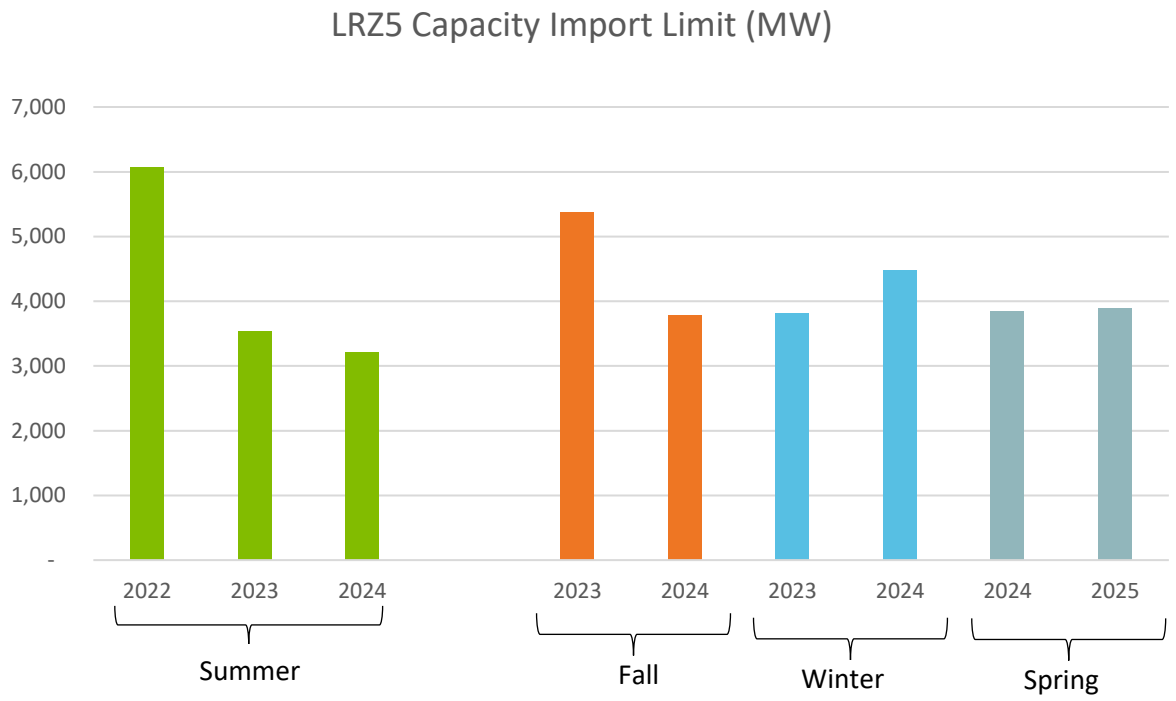
		Summer		Difference		Fall		Difference	
		2024	2023	MW	%	2024	2023	MW	%
(A)	Zonal Coincident Peak Forecast (ZCPF)	7,532.3	7,450.3			6,911.9	6,591.9		
(B)	Transmission Loss (TL) for ZCPF (MW)	147.9	130.7			168.2	115.2		
(C)=(A)+(B)	LRZ Peak Demand	7,680.2	7,581.0	99.2	1.3%	7,080.1	6,707.1	373.0	5.6%
(D)	LRR UCAP/LRZ Peak Demand from LOLE	1.331	1.333			1.441	1.452		
(E)=(C)*(D)	Local Reliability Requirement (LRR)	10,222.3	10,105.5	116.9	1.2%	10,202.4	9,738.7	463.7	4.8%
(F)	Zonal Import Ability (ZIA)	3,208.0	3,576.0	(368.0)	-10.3%	3,786.0	5,380.0	(1,594.0)	-29.6%
(G)	Controllable Exports	0.0	0.0			0.0	0.0		
(H)=(E)-(F)-(G)	Local Clearing Requirement (LCR)	7,014.3	6,529.5	484.9	7.4%	6,416.4	4,358.7	2,057.7	47.2%

		Winter		Difference		Spring		Difference	
		2024-25	2023-24	MW	%	2025	2024	MW	%
(A)	Zonal Coincident Peak Forecast (ZCPF)	6,397.0	6,483.2			6,023.0	5,921.4		
(B)	Transmission Loss (TL) for ZCPF (MW)	247.8	188.3			117.6	109.8		
(C)=(A)+(B)	LRZ Peak Demand	6,644.8	6,671.5	(26.7)	-0.4%	6,140.6	6,031.2	109.4	1.8%
(D)	LRR UCAP/LRZ Peak Demand from LOLE	1.285	1.474			1.618	1.610		
(E)=(C)*(D)	Local Reliability Requirement (LRR)	8,538.6	9,833.8	(1,295.2)	-13.2%	9,935.5	9,710.2	225.3	2.3%
(F)	Zonal Import Ability (ZIA)	4,477.0	3,811.0	666.0	17.5%	3,892.0	3,881.0	11.0	0.3%
(G)	Controllable Exports	0.0	0.0			0.0	0.0		
(H)=(E)-(F)-(G)	Local Clearing Requirement (LCR)	4,061.6	6,022.8	(1,961.2)	-32.6%	6,043.5	5,829.2	214.3	3.7%

Capacity Import Limits
Zone 5: Missouri

LRZ5	Monitored Element	Monitored Element Rating	Contingency	CIL
Summer 2024	Moro - Miles 138 kV	305 MVA	Roxford - Moro 345 kV	3208
Fall 2024	Moro - Miles 138 kV	305 MVA	Roxford - Moro 345 kV	3786
Winter 2024/25	Moro - Miles 138 kV	329 MVA	Roxford - Moro 345 kV	4477
Spring 2025	Moro - Miles 138 kV	305 MVA	Roxford - Moro 345 kV	3892





From 10/17/23 LOLEWG: Item 04 PY 2024-25 Final CIL-CEL Results Slide 11

Visit MISO's Help Center
for more information
https://help.misoenergy.org/

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-7

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

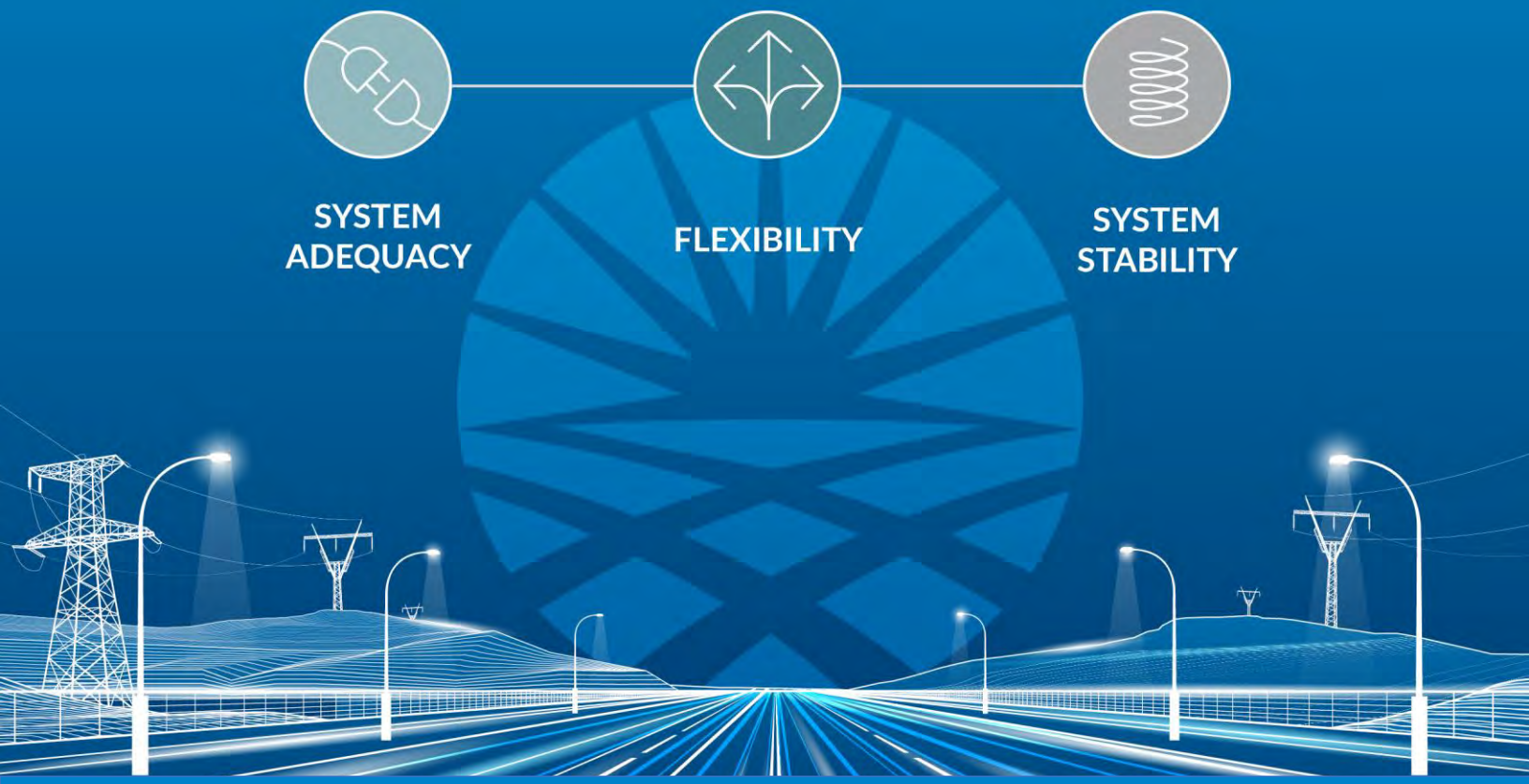
Filed September 5, 2025

Exhibit 85

MISO Attributes Roadmap

Attributes Roadmap

A RELIABILITY IMPERATIVE REPORT



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

MISO

misoenergy.org

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System Adequacy **9**

Roadmap: Further modernize the resource adequacy construct 17

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Roadmap: Focus market signals on emerging flexibility needs 29

Roadmap: Enable emerging resources' potential 32

System Stability **35**

Roadmap: Require capabilities to strengthen the grid 44

Acknowledgments **51**

Version Number	Purpose / Change	Date
1.0	Initial posting.	December 2023
1.1	Updated with hyperlinks between the *Technical Appendix* and the *Attributes Roadmap* 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.

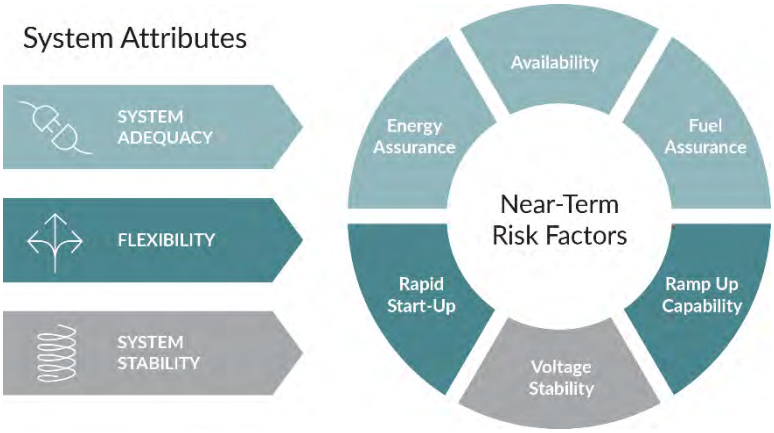


Figure 1: Three priority system reliability attributes and their near-term risk factor focus areas

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.

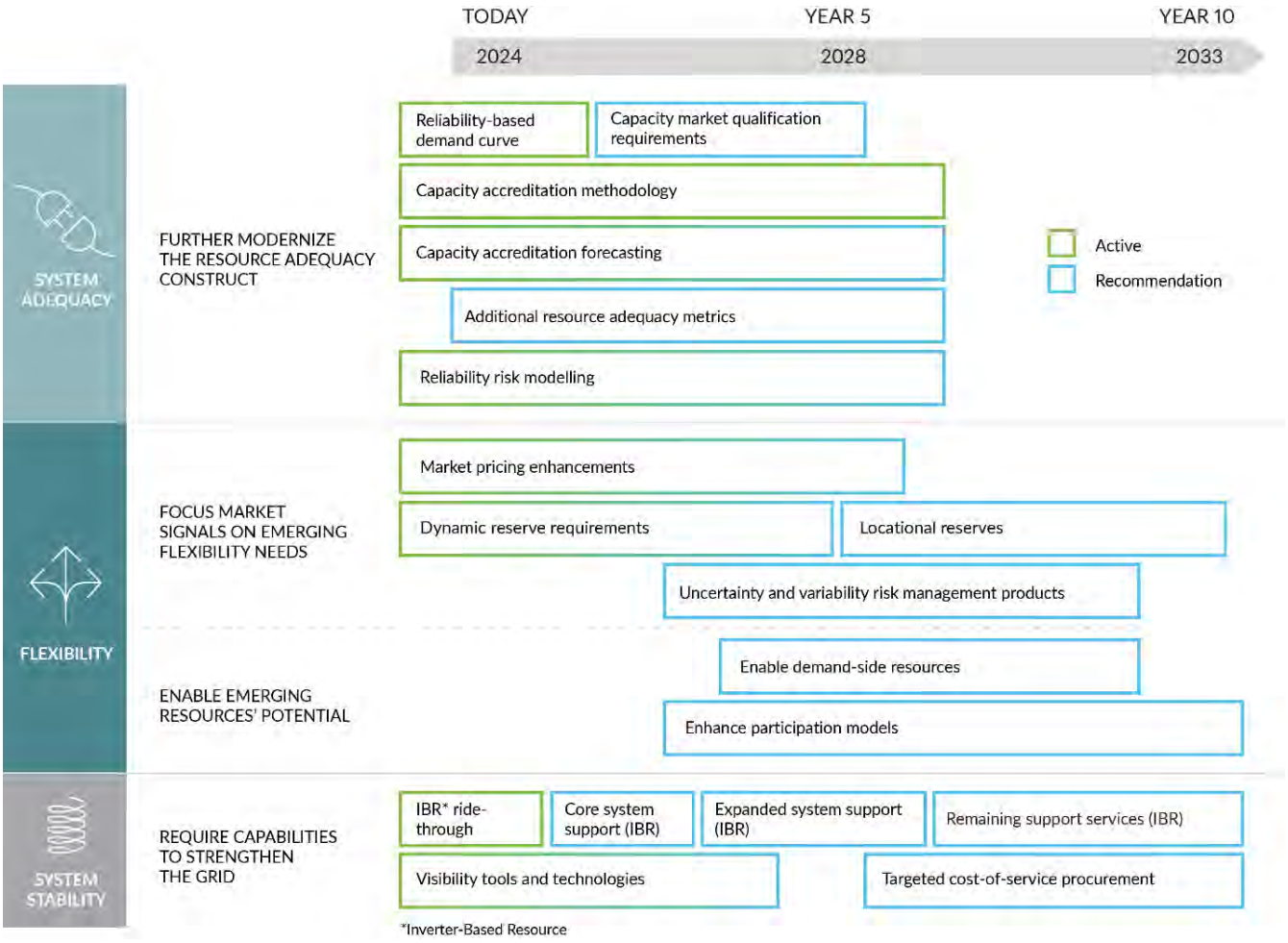


Figure 2: Hypothesis for attributes solution roadmap with approximate timing for projects currently underway (active) and proposed future projects (recommendation). The *Attributes Roadmap* discusses each recommendation in detail as well as the analysis and supporting research.

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.

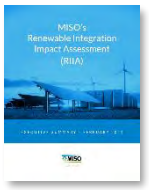
PAST STUDIES INFORM PRIORITIZATION AND APPROACH

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.

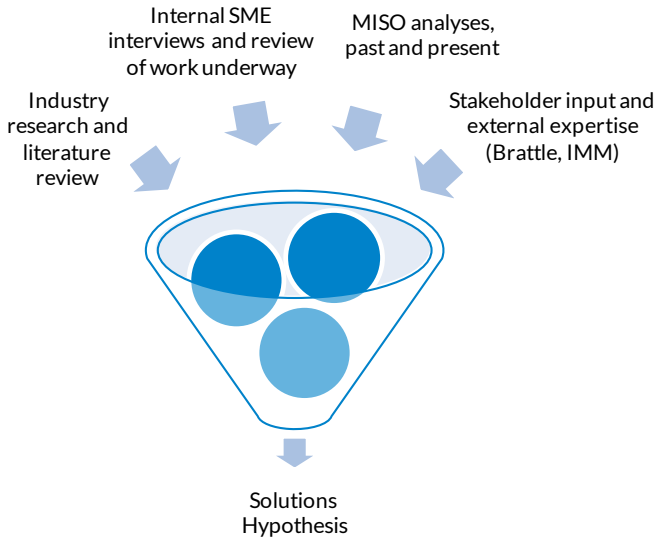


Figure 3: Sources of solutions considered

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) method[5] at the class level and the previously defined Resource Adequacy hours[6] 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.

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[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.

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

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.

[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.

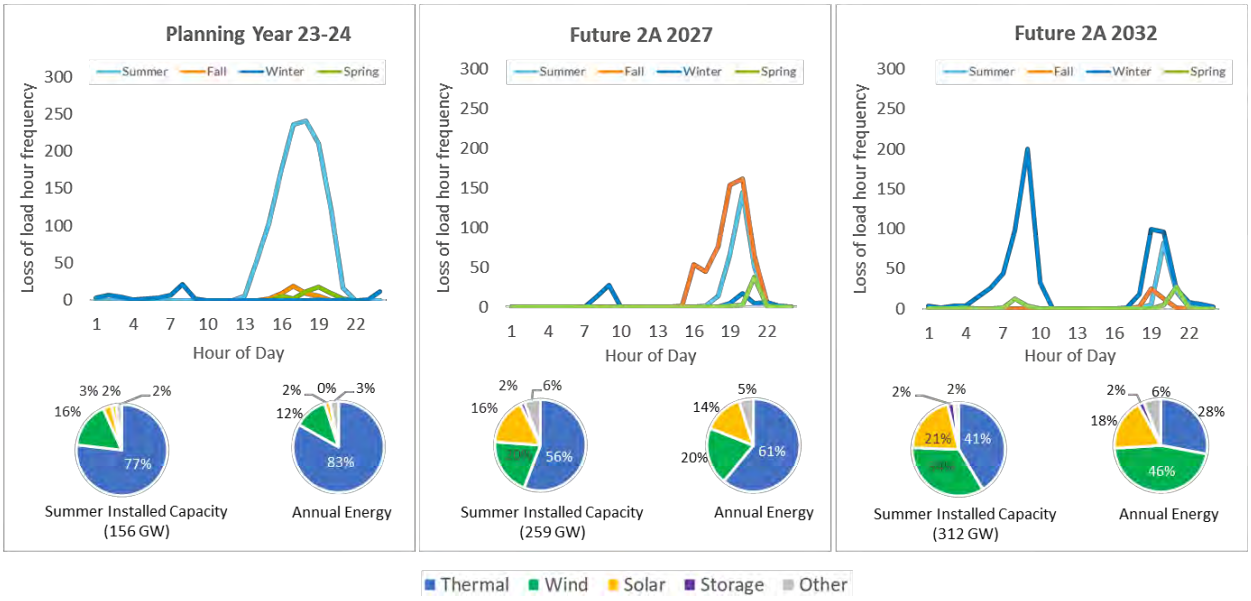


Figure 5: Evolution of risk distribution in future portfolios

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.

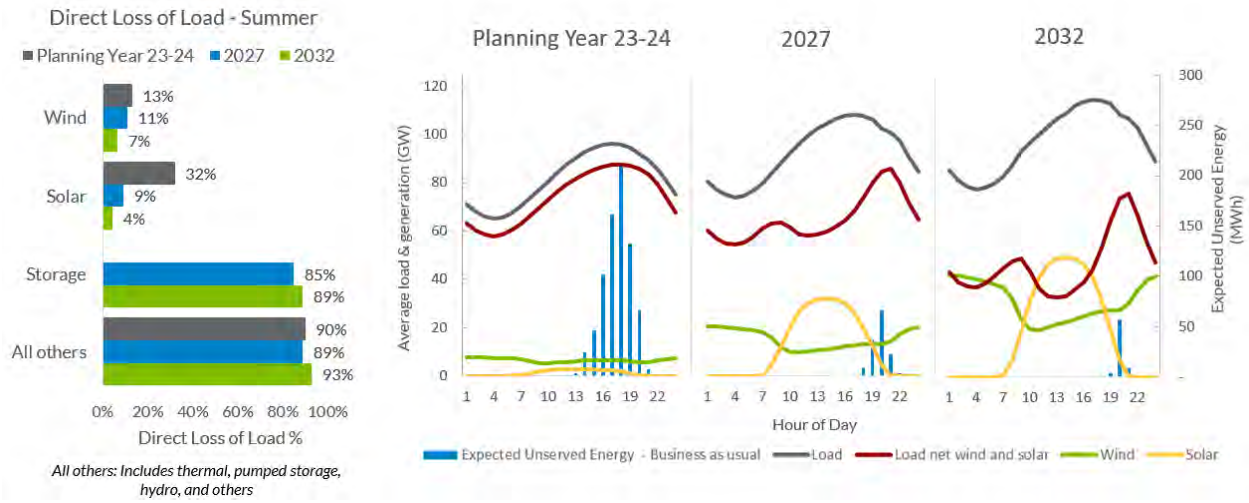


Figure 6: On the left, estimated summer season, class-level DLOL accreditation values for the three portfolios (today, 2027, and 2032) by fuel type. On the right, summer diurnal plots from the LOLE simulations showing average load, net load, and renewable generation for each hour.

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 resources[10], as their ability to mitigate risk is proportional to their state of charge at the beginning of the event and total energy available.

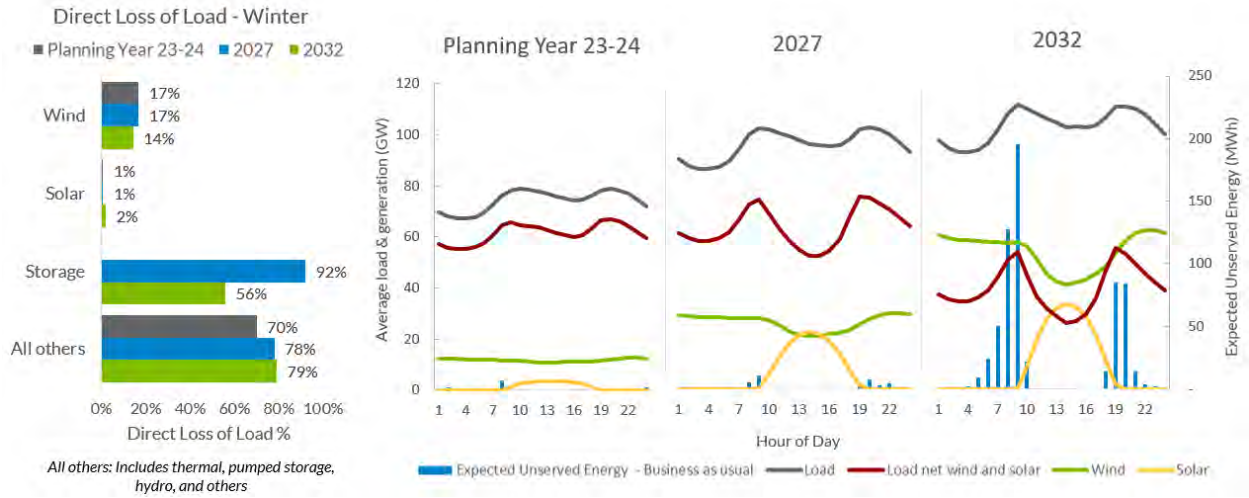


Figure 7: On the left, estimated winter season, class-level DLOL accreditation values for the three portfolios (today, 2027, and 2032) by fuel type. On the right, winter diurnal plots from the LOLE simulations showing average load, net load, and renewable generation for each hour.

[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" units[11] 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]

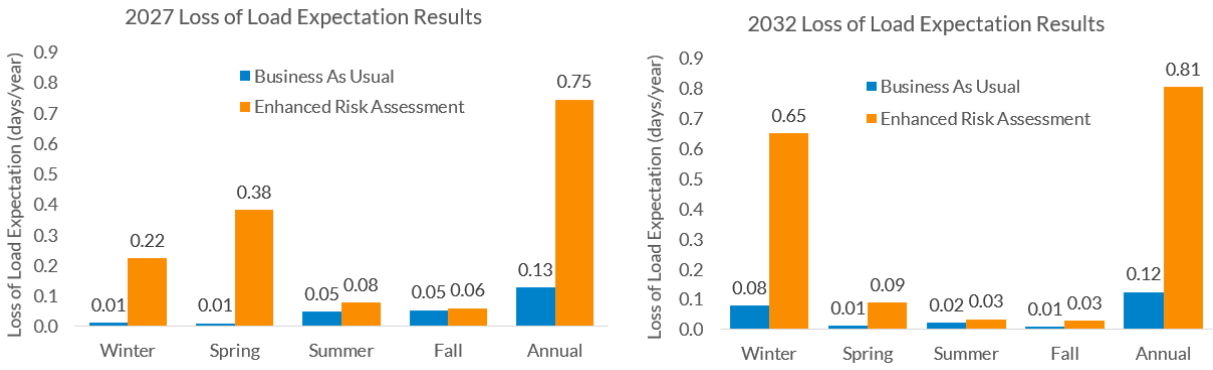


Figure 8: Seasonal LOLE results for the business-as-usual and enhanced risk assessment cases when both at the same adjustment.

The inclusion of the RDT constraint also had an impact on wind and storage accreditation values; the difference in DLOL 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.

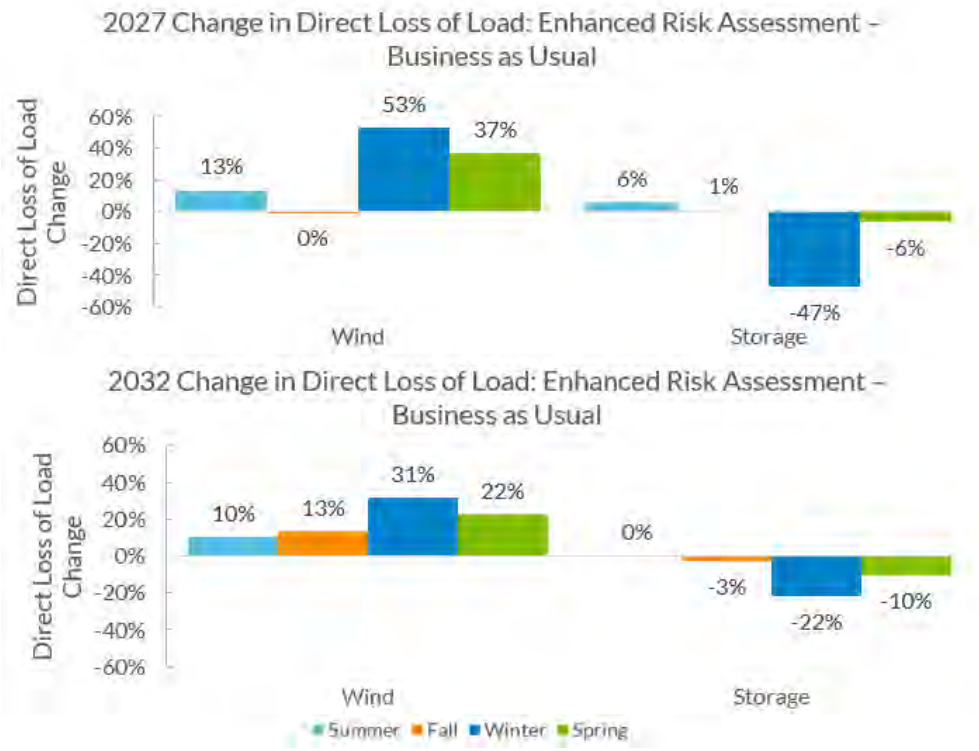


Figure 9: DLOL deltas between the enhanced risk assessment and business-as-usual cases for wind and battery storage resource classes when both cases are adjusted to seasonal LOLE targets.

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.

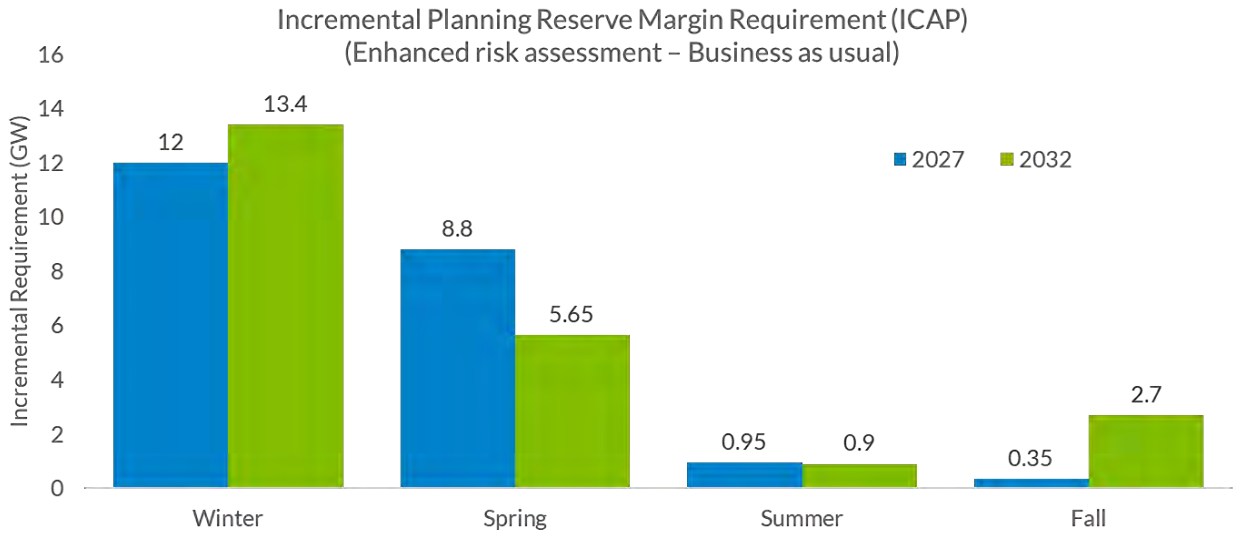


Figure 10: Incremental planning reserve margin requirement (PRMR) by season

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

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 ramping[13]) was selected for the planning year 22-23 and 2032 business-as-usual models.

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

[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.

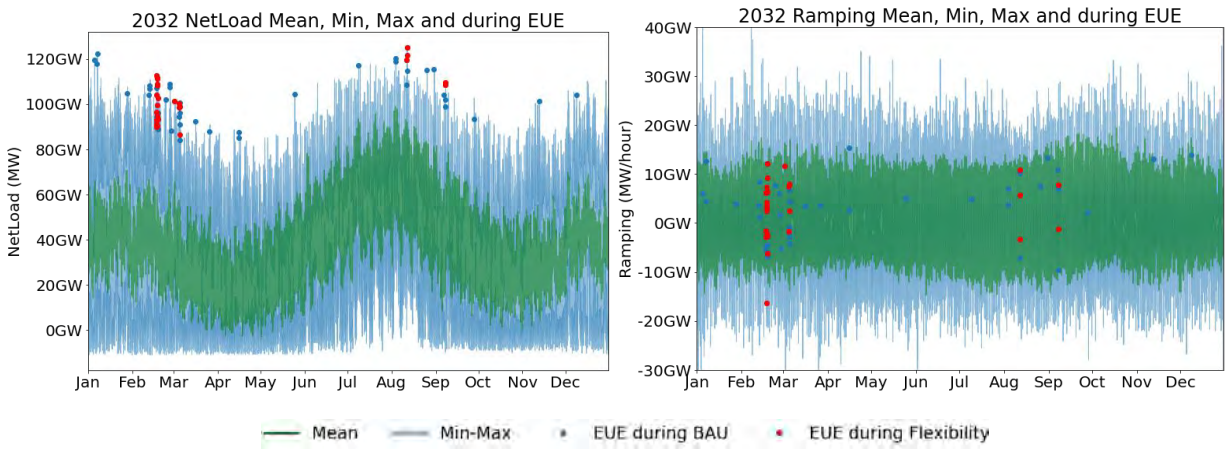


Figure 11: 2032 average, minimum, and maximum netload (left) and netload ramping (right). Blue and red dots signify netload and ramping at the event sample in business-as-usual and Flexibility

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

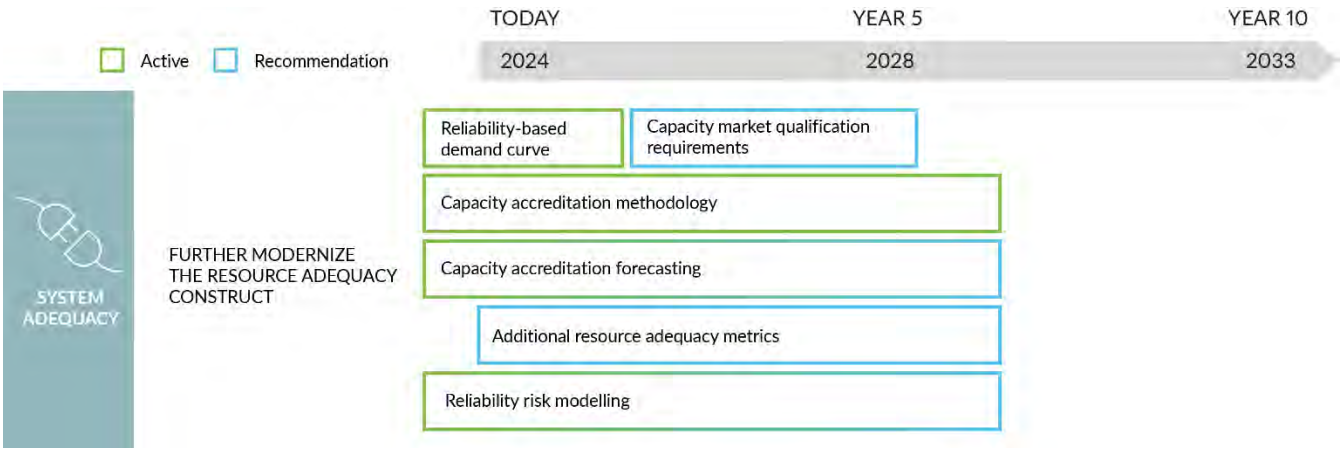
The *Attributes Roadmap* does not recommend new discrete capacity products (e.g., ramp capacity, energy reserves, or winter fuel programs). Capacity products outside the current construct may suppress energy and capacity prices. Additional products will increase complexity, requiring careful operational 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 approach[14] 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.

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[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 technologies[19] 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.

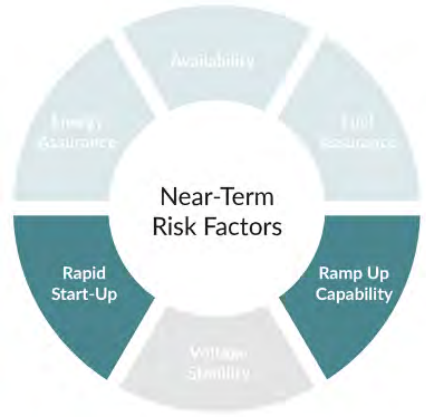


Figure 12: Flexibility near-term risk factor focus areas

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.

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 load[23] 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.

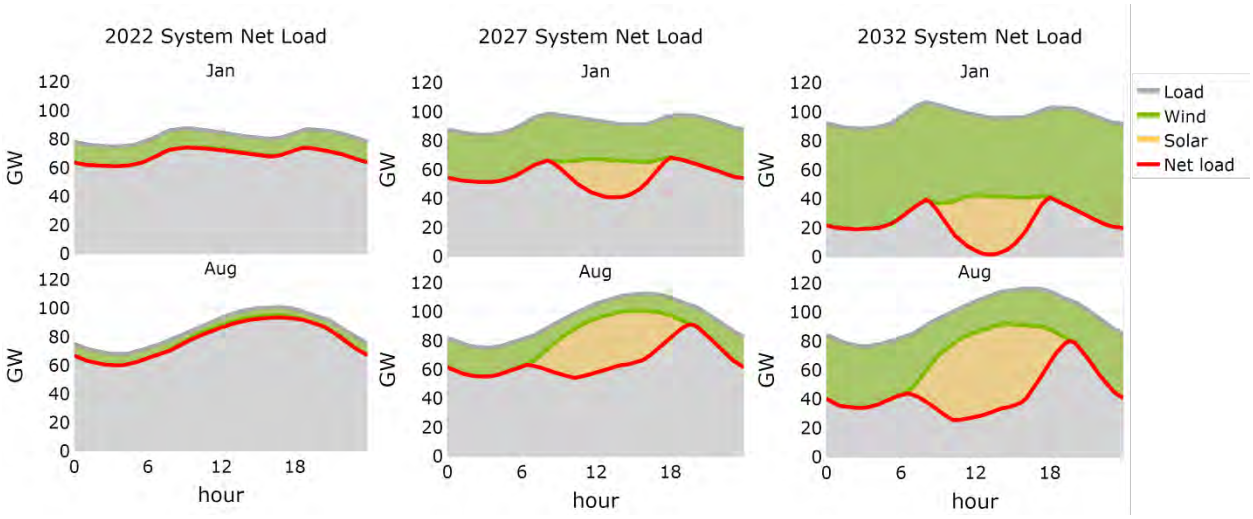


Figure 13: Monthly averages of diurnal net load components for January and August

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.

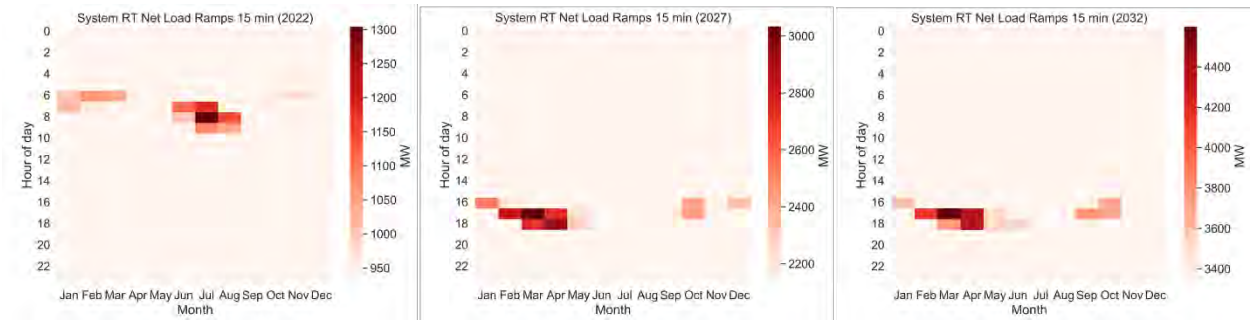


Figure 14: Highest 10 percentile of short duration net load up-ramps

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.

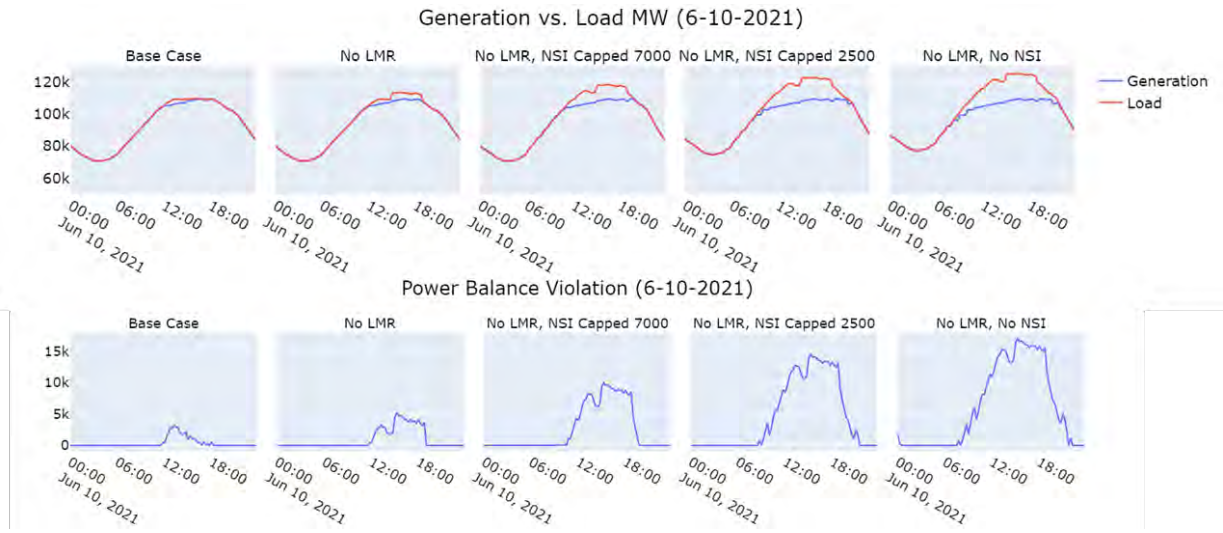


Figure 15: Simulation results for the summer event under different LMR and NSI scenarios

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).

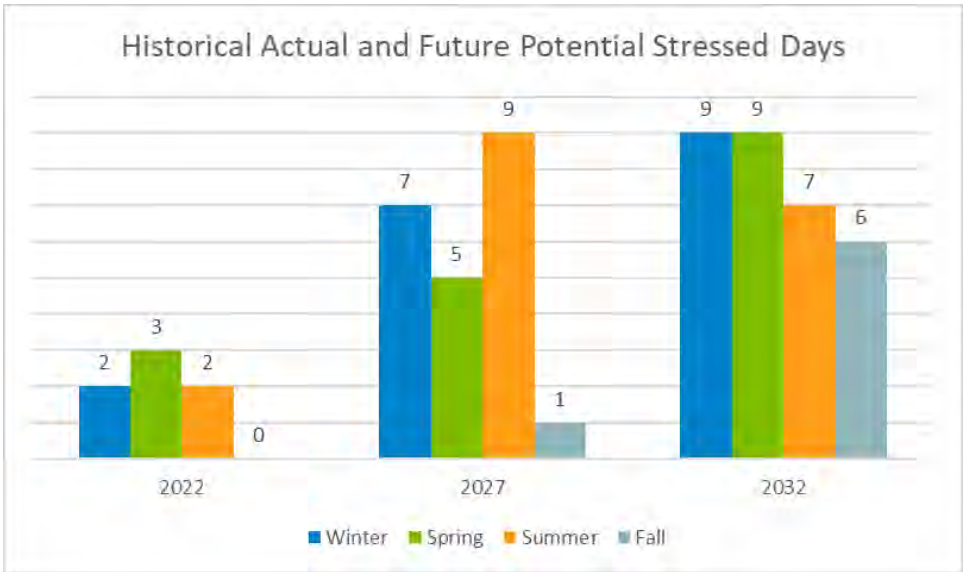


Figure 16: Historical events and future potential stressed days by season

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.

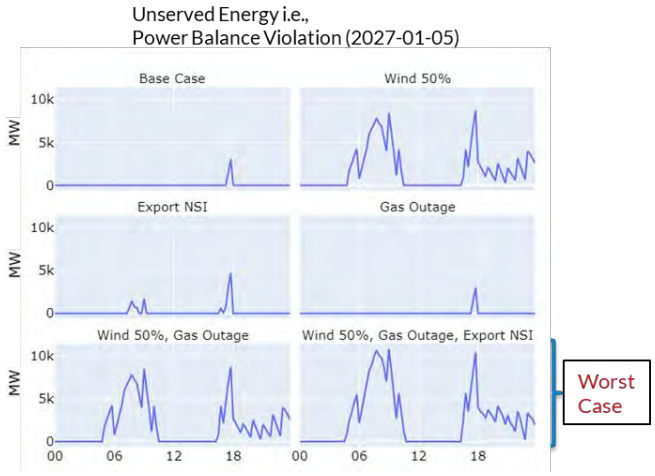


Figure 17a: Simulation results for base case and stressed scenarios for the winter 2027 event

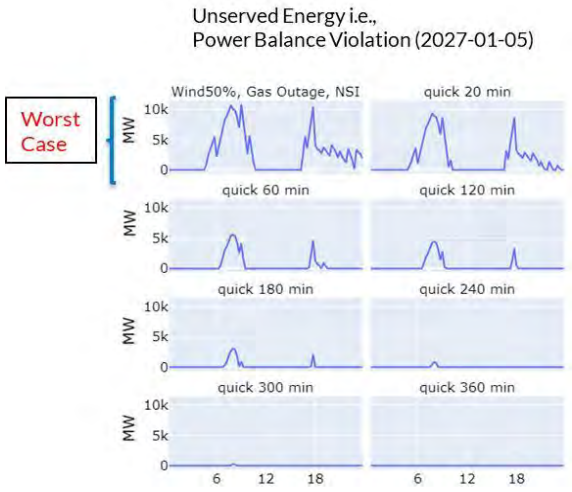


Figure 17b: Simulation results for worst stress case and mitigation using quick start units for the winter 2027 event

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.

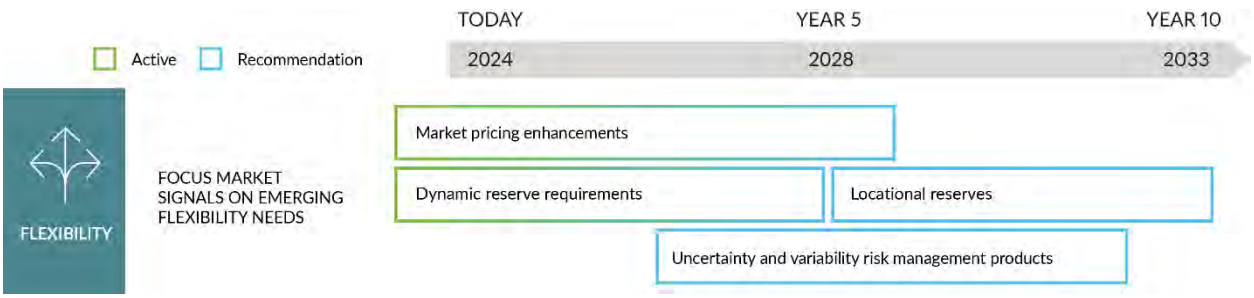
WHAT NOT TO DO NOW

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

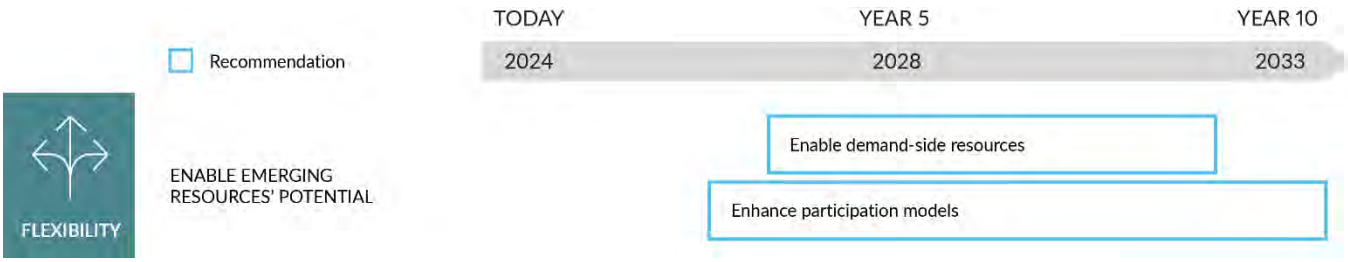
Currently in MISO's market resources must be able to provide both upward and downward ramp to participate in the ramp capability product. This places limitations on some types of resources from participating in the ancillary services market. MISO should separate the qualification requirements for upward 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 • 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 • 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]

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

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.

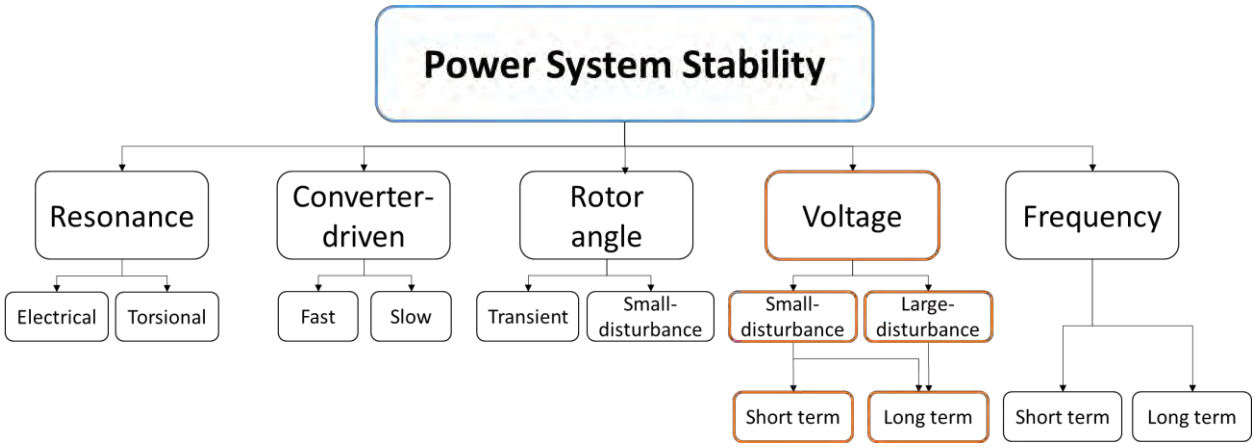


Figure 19: Taxonomy of power system stability considerations

[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.

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[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.

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.

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]

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.

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[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".

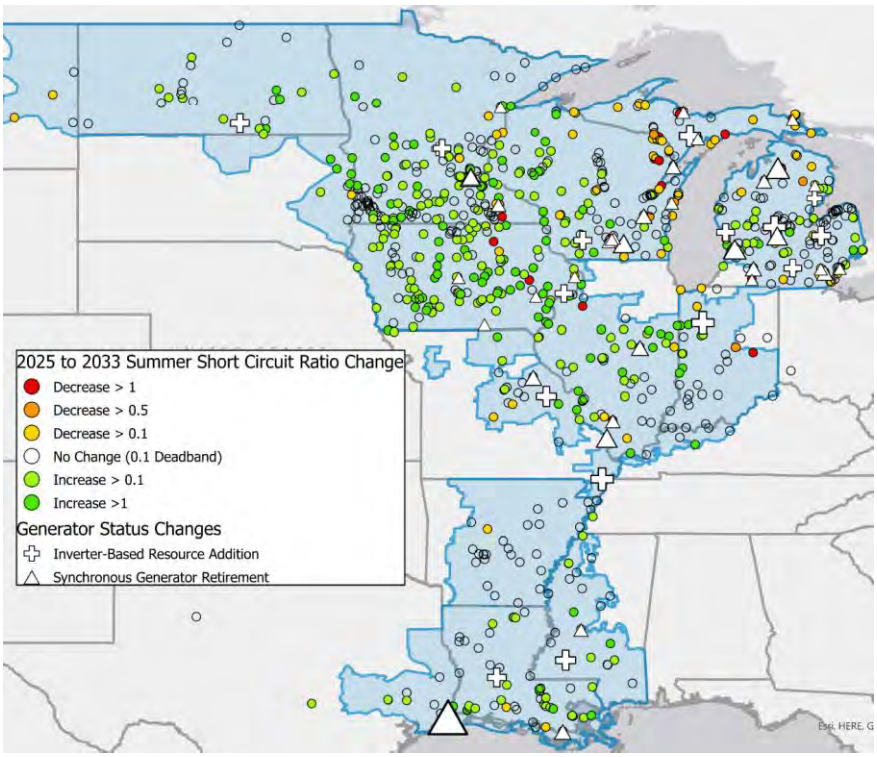


Figure 20: Change in short circuit ratio (SCR) between MTEP23 2025 summer peak and MTEP23 2033 summer peak cases[34]

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.

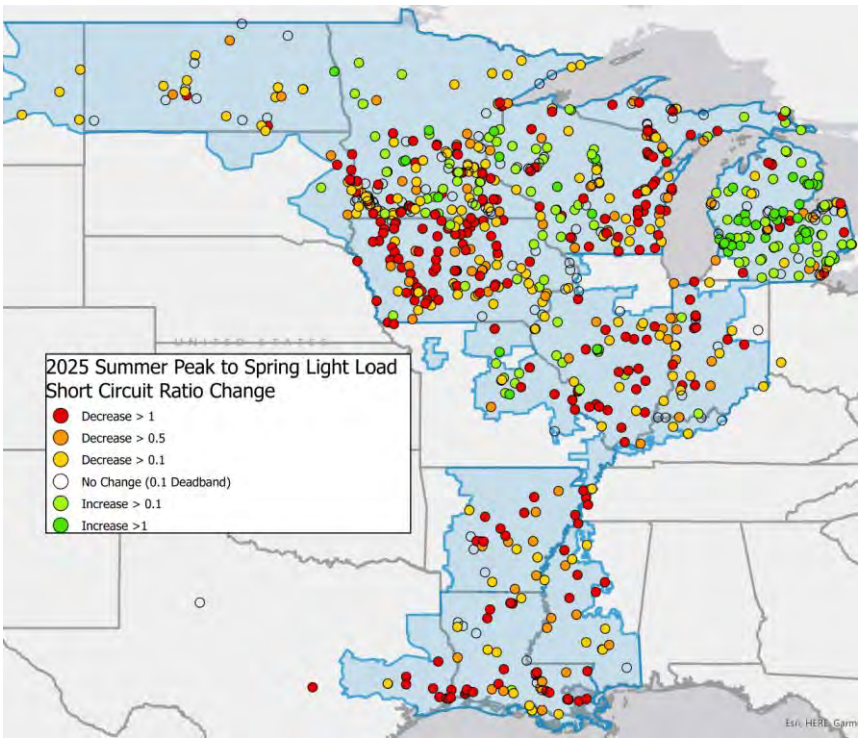


Figure 21: Change in short circuit ratio (SCR) between MTEP23 2025 summer peak and spring light load

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.

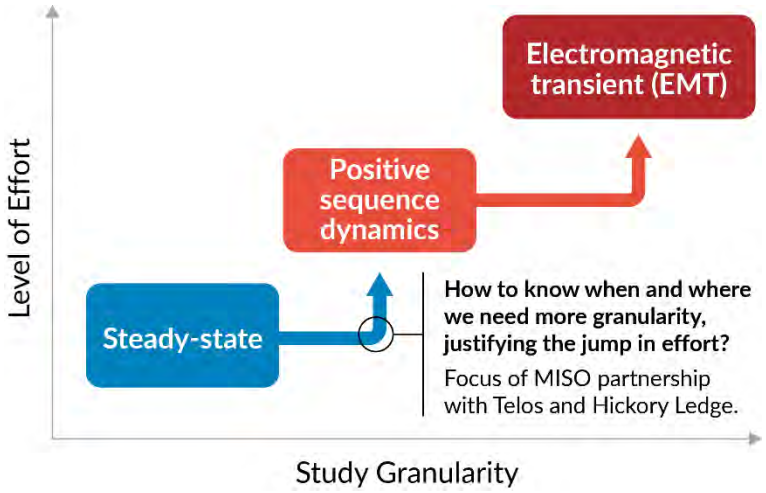


Figure 22: Illustration of effort-granularity tradeoff of common power system analysis tools

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*.

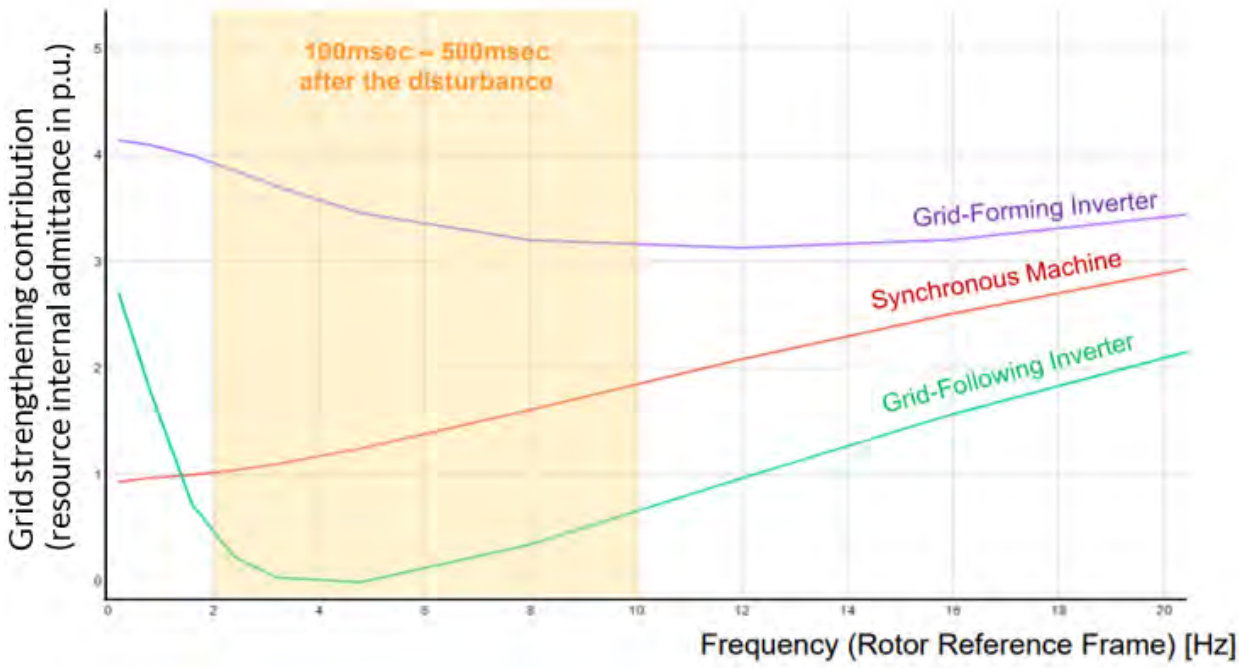


Figure 23: Resource characterization results from a series of detailed electromagnetic transient (EMT) simulations using detailed models. ***Image source: Telos Energy***

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.

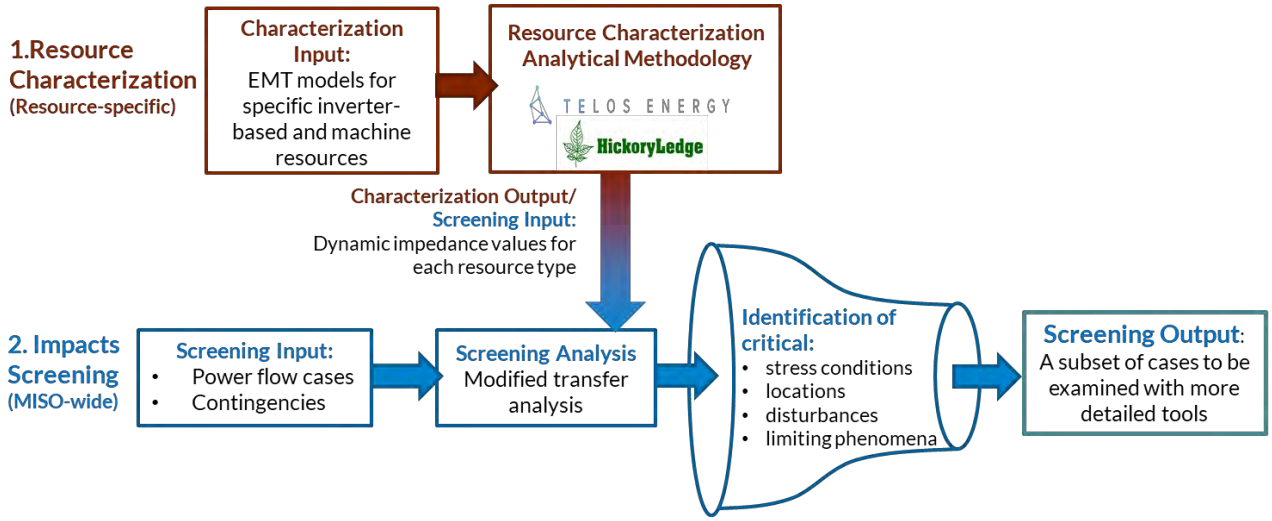


Figure 24: Overview of resource characterization and dynamic impedance screening process, described in greater detail in the Technical Appendix.

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.

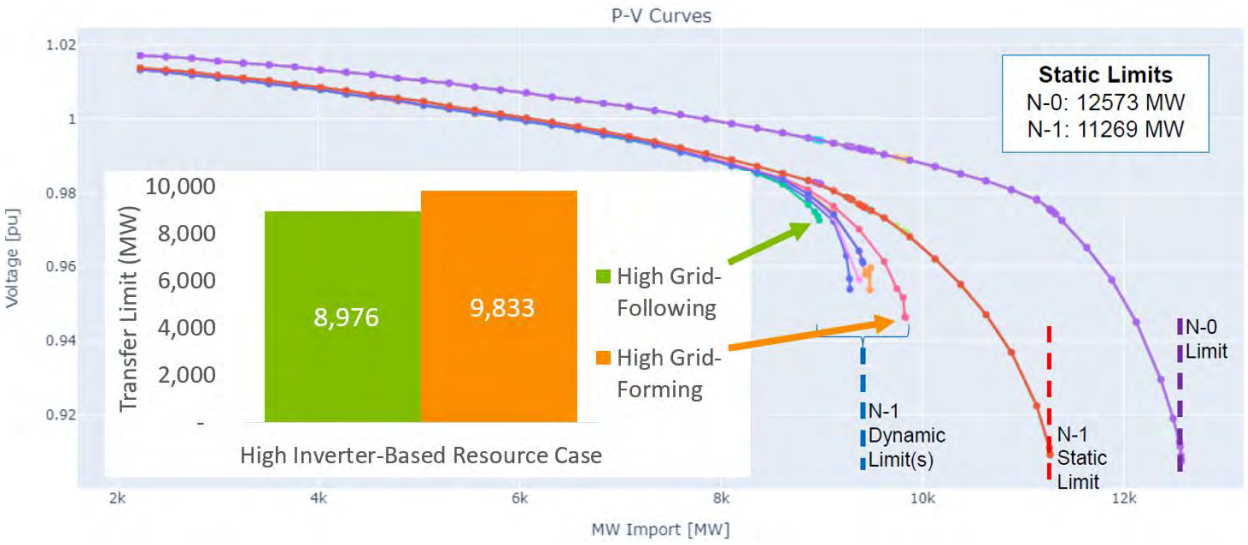


Figure 25: Dynamic impedance screening results comparing four select cases, varying IBR levels and grid-forming to grid-following proportions.

[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

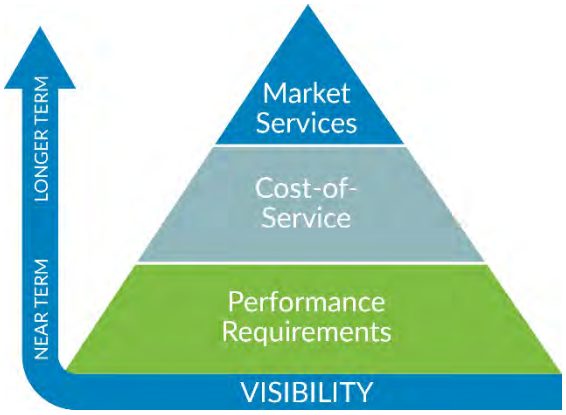
Stability challenges, including voltage stability, are best addressed in the planning timeframe by regulatory solutions because reactive deficiencies and solutions are highly localized. Obvious, low-cost solutions may be coordinated by technology standards and controls. Functionally, the types of solutions 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.

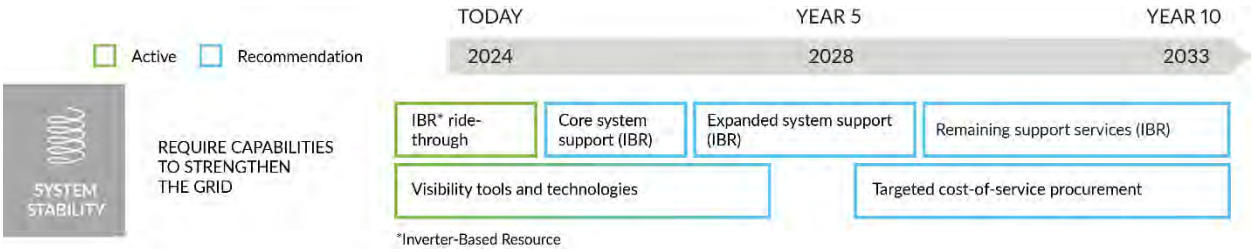


WHAT NOT TO DO NOW

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 services[38], 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
Require **ride-through capabilities** for interconnection of inverter-based resources (IBR) to address unexpected tripping • 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
Require **core system support** capabilities for interconnection of IBRs to support system stability more actively • 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
Require **expanded system support** with more active IBR controls to support a system with high levels of IBR • 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
Require **remaining support services** to enable an IBR-dominant system • 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
Evaluate **targeted cost-of-service procurements** to incentivize other technologies and the "energy buffer" required for more advanced grid-forming IBR performance • 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
Advance **visibility tools and technologies** to make visible of shifting risks and support further solution evaluation • 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).

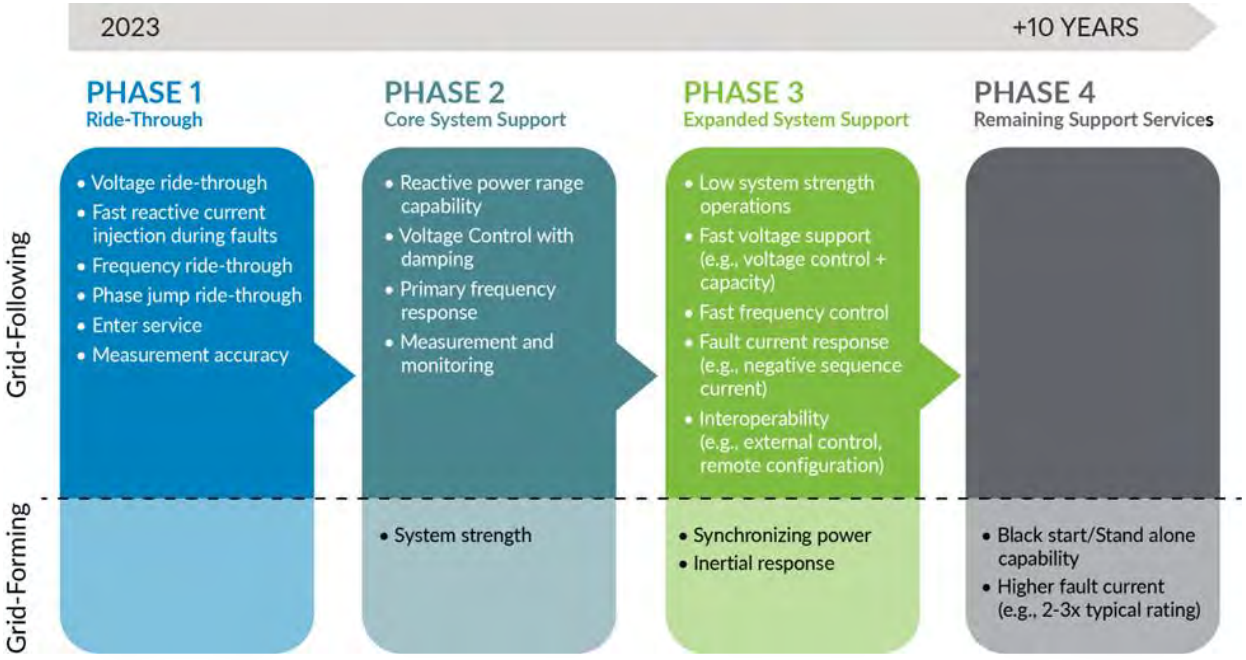


Figure 27: Summary of MISO's phased recommendation on grid-following and grid-forming capabilities and performance requirements

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.

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 Operator [1] 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.*

Regarding grid-following performance, MISO recommends expanding adoption of the IEEE 2800-2022[43] 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.

[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 P2800.2[44] will aide 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 response[45], 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]

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[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.

—

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

AEMO: Australian Energy Market Operator

BESS: Battery Energy Storage System

CCGT: combined-cycle gas turbine51

CVaR: Conditional Value at Risk

DER: Distributed Energy Resource

DLOL: Direct Loss of Load

EGRET: Electric Grid Research & Engineering Tool

EMS: Energy Management System

EMT: Electromagnetic Transient

EPRI: Electric Power Research Institute

EUE: Expected Unserved Energy

FERC: Federal Energy Regulatory Commission

GFL: Grid Following

GFM: Grid Forming

HVDC: High Voltage Direct Current

IBR: Inverter-Based Resource

IEEE: Institute of Electrical and Electronics Engineers

IMM: Independent Market Monitor

LAC: Look-Ahead Commitment

LMR: Load Modifying Resource

LOLE: Loss of Load Expectation

LOLH: Loss of Load Hours

MISO: Midcontinent Independent System Operator

MTEP: MISO Transmission Expansion Plan

NERC: North American Reliability Corporation

NOPR: Notice of Proposed Rulemaking

NSI: Net Scheduled Interchange

PRA: Planning Resource Auction

PRM: Planning Reserve Margin

PRMR: Planning Reserve Margin Requirement

RAN: Resource Availability and Need

RBDC: Reliability-based demand curve

RDT: Regional Directional Transfer

RIIA: Renewable Integration Impact Assessment

RRA: Regional Resource Assessment

RTO: Regional Transmission Organization

SCR: Short Circuit Ratio

STATCOM: Static Var Compensators, Static Synchronous Compensators

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-7

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

Filed September 5, 2025

Exhibit 86

MISO Attributes Roadmap Technical Appendix

Technical Appendix: Attributes Roadmap

Version Number	Purpose / Change	Date
1.0	Initial posting.	December 2023
1.1	Updated with hyperlinks between the *Technical Appendix* and the *Attributes Roadmap* per stakeholder feedback.	June 2024

Introduction

This technical appendix provides a detailed discussion of the data inputs, analytical tools, methods, modeling assumptions and results that support the insights presented in MISO's 2023 *Attributes Roadmap*. The analysis of current and future portfolios informed the selection and prioritization of the solution hypothesis in that document.

MISO's attributes effort began by studying industry research and the experiences and approaches of other grid operators facing similar challenges. This landscape review, in addition to MISO's past analyses and experiences, led to the identification of three priority system attributes where near-term risk for the MISO system is most acute: system adequacy, flexibility, and system stability (Figure 1).

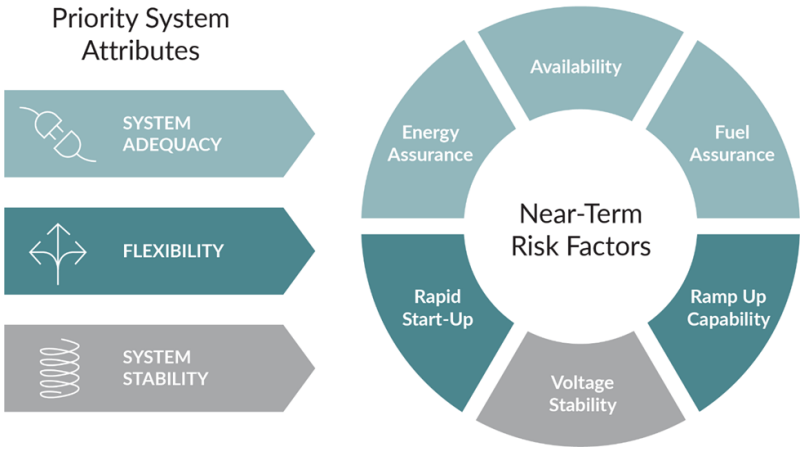

Figure 1. Three priority system attributes and near-term risk factor focus areas

System Adequacy is the ability to serve load in all realistic scenarios, including the most challenging periods, by having enough supply to meet demand when and where it is needed. Generation capacity is considered when measuring this attribute, as well as actual availability every hour of the year. As the system adds more weather-dependent generators, the risk hours shift away from the traditional summer peak and increasingly to non-summer months. Maintaining reliability through multi-day periods of low renewable resource output, or correlated outages due to fuel supply or utilization issues presents new and additional energy and fuel assurance risk factors.

Flexibility is the ability to meet the ramping needs of the system with multiple response timeframes and durations. As generation becomes more weather-dependent and electrification trends change traditional load patterns, the complexity of forecasting and operations increases significantly, leading to greater system uncertainty and variability. MISO has identified rapid start-up and ramp up capability as near-term risk factors, but flexibility in a broader sense includes ramp rates, shut-down times, and minimum generation levels. A more flexible future system will be required to meet the emerging challenges and ensure reliability while maximizing economically efficient operations and system investments.

System stability is the ability to remain in a state of operating equilibrium under normal conditions and to recover from disturbance events, including unplanned generation outages and rapid changes in generation output driven by changing weather. MISO identified voltage stability as the nearest term stability risk. Voltage stability is often thought of as load-driven rather than resource-driven, though resource characteristics affect stability outcomes. The addition of inverter-based resources and retirement of resources that historically provided sufficient reactive power, requires a new approach to ensure ongoing reliability and stable outcomes.

Over the course of 2023, MISO has designed and performed foundational quantitative analyses to gain improved insights and understanding to better describe and define the system attributes today and under five-year and 10-year future scenarios. The team studied potential market reforms from two perspectives: (1) the planning horizon (long-range investment and retirement timeframe) where the risk is not having sufficient resources, and (2) the operating horizon (near real-time timeframe) where the risk is not using available resources efficiently.

This technical appendix summarizes this effort and is organized in the following sections:

A. System Adequacy

B. Operational Adequacy

C. Voltage Stability

D. Attribute Support from MISO's Market Structures

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A.System Adequacy

This section of the appendix provides supplemental information on the analysis described in the System Adequacy section of MISO's 2023 *Attributes Roadmap*. The analysis informs the development of the solution hypothesis by quantifying the impact of emerging risk factors (availability, energy, and fuel assurance) on MISO-wide accreditation and planning requirements using a resource adequacy analysis that follows best practices. This analysis also explored the implications of including operational constraints in resource adequacy models. This approach was used to analyze both the current portfolio and future portfolios using MISO's Future 2A[1].

A.1 Methodology

A.1.1 Resource Adequacy Analysis

Resource adequacy analysis, as required by the North American Electric Reliability Council (NERC) Standard BAL502-RFC-0211, aims to ensure sufficient installed generation capacity to meet electric load, measured against a prescribed target. The objective of the resource adequacy analysis in the System Adequacy portion of the Attributes work is to understand how the risk of unserved energy changes with the evolving resource mix over the next decade. The resource adequacy analysis aims to identify changes to the planning reserve margin requirement (PRMR) and accreditation of resources through the direct loss of load (DLOL) method[2]. As the resource mix rapidly changes with the addition of renewable and storage resources, it becomes clear that these resources play an important role in serving load and maintaining system reliability. The stochastic and energy-limited nature of these resources result in changes to the reliability risk profile and a shift in the probability of loss of load to periods outside of the traditional risk periods.

The System Adequacy analysis uses a seasonal resource adequacy construct to estimate DLOL using MISO's currently established metric of a loss of load expectation (LOLE) of 1 day in 10 years. The LOLE analysis uses a sequential Monte Carlo simulation to model a wide range of system conditions and assess the system's reliability. The LOLE analysis is a chronological, 8,760-hour simulation and includes multiple weather years. Multiple samples are developed for generator forced outage profiles for each weather year. LOLE, and other metrics, are calculated using an average across samples and weather years.

To capture the interannual variability of weather-related patterns, synchronized load, wind, and solar hourly datasets were used for the study. Thermal outages are accounted for in the form of planned and forced outages. The former is determined by the maintenance rate and mean time to repair while the latter uses the forced outage rate. In summary, the analysis considers the variability of load, wind, and solar output along with planned maintenance and forced outages of generation units. The modeling inputs vary slightly from the standard business practice to incorporate the expanded scope of the attributes work.

Following current practices at MISO, the LOLE model was adjusted and brought to criteria. First, the simulation is run without any adjustments and the resulting natural LOLE is determined. Next, annual adjustments are performed by adding or removing fixed load so that the average LOLE across all weather years reaches 0.1 days/year. For seasons with no LOLE resulting from this process, seasonal adjustments are then made to the system until each season results in a LOLE of at least 0.01 days/year. If the LOLE is less than the target for a season, then fixed load is added to the model. If the LOLE is greater than the target for a season, then proxy combustion turbine generators

[1] MISO, *MISO Futures Report, Series 1A*, November 2023.

[2] MISO, *Resource Accreditation White Paper, Version 1.1*, November 2023.

with a size of 160 MW and class average equivalent forced outage rate (EFORd) are added to the model until the seasonal LOLE target is achieved.

A.1.2 Tools

The Planning Adequacy analysis uses a program developed by Energy Exemplar called PLEXOS to perform the resource adequacy assessment. The PLEXOS model is a probabilistic, hourly chronological simulation over the study year, which uses the sequential Monte Carlo method to develop random forced outage samples. Planned thermal outages are determined by the maintenance rate and mean time to repair, while forced outages use historical forced outage rates. Both the planned maintenance and sequential Monte Carlo are based on optimization techniques.

A.1.3 Datasets

In Planning Adequacy analysis, weather-dependent characteristics of load, wind and solar generation, and extreme weather-dependent thermal generation outage were collected to represent the diverse operating conditions. For the PY23-24 model, the 2022 Regional Resource Assessment (RRA) model was aligned with MISO's LOLE study[3] model. The equivalent datasets for F2A 2027 and 2032 models are sourced as below:

- Load: Actual load recorded for the operation years 2007-2021 was collected and scaled based on energy and capacity peaks specified by MISO Future 2A's assumptions[4].
- Wind and solar generation: For all existing and planned siting, hourly forecasted generation was calculated based on each siting's geographical location, using National Renewable Energy Laboratory's (NREL) and Vibrant Clean Energy's dataset of weather years 2007-2021. The generation was aggregated per Local Resource Zone (LRZ) for the simulations.
- Extreme weather-dependent thermal generation outage: Temperature- and fuel-dependent outages were analyzed to create hourly correlated outages, scaled to the capacity of thermal generation in each model.

A.1.4 Accreditation

In addition to examining how risk evolves in LOLE models under different assumptions, MISO studied the impact on the capacity value of different resources. Accreditation estimates were calculated for different resource classes and followed MISO's DLOL class accreditation proposal,[5] as of September 2023. The DLOL method calculates a resource's resource adequacy contribution by measuring its ability to serve load during times of system shortfall events in the LOLE model.

Resource availability during modeled loss-of-load hours, across all samples, is aggregated by resource class. Average class-level availability is averaged by season and load forecast error (LFE) tranche, and the weighted average across LFE tranches results in the DLOL in MW terms. To express DLOL as a percentage, the available DLOL MW is divided by the resource class installed capacity. The standard MISO resource adequacy LOLE model includes the effect of LFE, but that feature was excluded from this analysis to reduce the amount of processing required for the scenarios in this analysis. Therefore, DLOL results in this study are not weighted by LFE probabilities. Similarly, the non-thermal technologies were aggregated into a single class for reporting purposes. Figure A-1 presents the DLOL calculation process as shown in MISO's accreditation white paper, which includes the LFE tranche steps.

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[3] MISO, *Planning Year 2023-2024 Loss of Load Expectation Study Report*, Updated May 2023.

[4] MISO, "Future 2A Energy Adequacy and Siting", Presented at MISO's LRTP Workshop, April 28, 2023.

[5] MISO, *Resource Accreditation White Paper, Version 1.1*, November 2023.

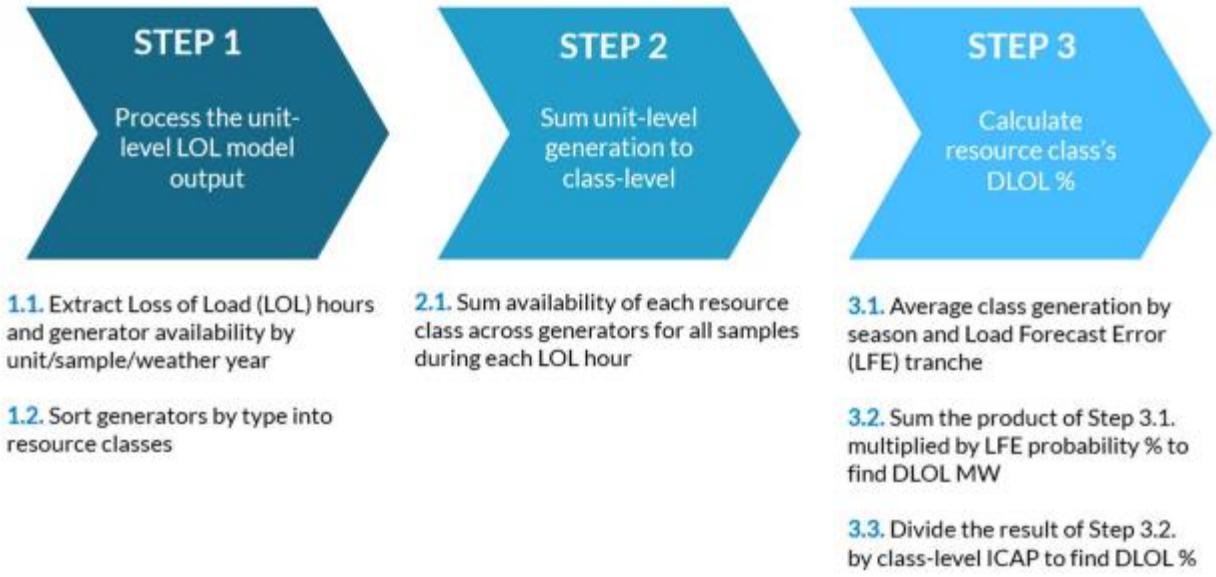


Figure A-1: DLOL calculation process from MISO's Resource Accreditation White Paper (v1.1)[5]

A high-level verification was performed to compare the outcomes of the planning year 23-24 (PY23-24) LOLE Study[6] and this work. Inputs were aligned as much as possible, but the use of different tools and techniques lead to small differences in the results[7].

A.2 Study Years and Data Sources

The System Adequacy analysis was designed to cover the energy transition that is expected to occur over the next decade to inform near term decisions about actions MISO should take to ensure system reliability attribute sufficiency. To that end three study years were selected: PY23-24, the year 2027, and 2032. Figure A-2 summarizes the major assumptions for these years. The first year was intended to represent current system conditions and its assumptions are aligned with the PY23-24 LOLE Study[8]. 2027 and 2032 represent medium- and longer-term forecasts and they are consistent with the Future 2A expansions in the MISO Futures Report[9].

[6] MISO, "Market Redefinition: Accreditation Reform", slide 6, presented at MISO's RASC, October 4, 2023.

[7] A benchmark of the results was shared at MISO "System Reliability Attributes Analysis and Roadmap Workshop #2" presented at MISO's RASC workshop, October 31, 2023.

[8] MISO, *Planning Year 2023-2024 Loss of Load Expectation Study Report*, Updated May 2023.

[9] MISO, *MISO Futures Report, Series 1A*, November 2023.

PY23-24	•Probabilistic model •PY23-24 LOLE Study as basis for resource portfolio and load •30 weather years (1992-2021) •125 random outage samples per weather year
2027 & 2032	•Probabilistic models •Future 2A expansion as basis for resource portfolio and load •15 weather years (2007-2012, 2014-2021) •250 random outage samples per weather year •Load includes electrification and energy efficiency forecasts

Figure A-2: Main assumptions and sources by study year

The transition in the resource mix is presented in Figure A-3, which highlights the increase in variable renewable generation, coupled with the retirement of coal generation. The remainder of this subsection presents more details on the assumptions used across the study years, including those that lead to the capacity mix presented in the figure.

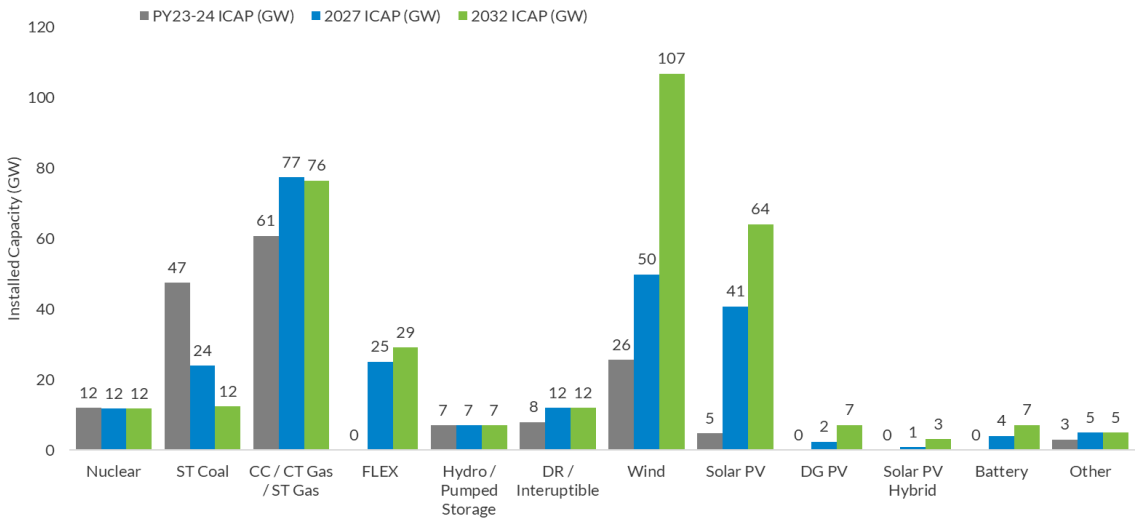


Figure A-3. Capacity mix assumed for the three study years

A.2.1 PY23-24 Base Model

The basis for the model in PLEXOS was the 2022 Regional Resource Assessment (RRA)[10], but data used for MISO's PY2023-2024 LOLE study[11] was incorporated into the PLEXOS model for the current year analysis. The study used 125 samples per weather year, and 30 weather years were included (1992-2021).

[10] MISO, *Technical Appendix: RRA Assumptions and Methodology*, from MISO, *2022 Regional Resource Assessment*, November 2022.

[11] MISO, *Planning Year 2023-2024 Loss of Load Expectation Study Report*, Updated May 2023.

Load

Hourly load data for each LRZ for each weather year was taken from the PY23-24 LOLE Study.

Generation

Installed capacity (ICAP) values were adjusted from 2022 RRA values to match the PY23-24 capacity values.

Seasonal forced outage rates (FOR) were incorporated into the model. These values were taken from the PY23-24 LOLE study on a unit-by-unit basis when units could be mapped, otherwise class average values were used. Mean, minimum, and maximum time to repair for forced outages were taken from the 2022 RRA, which used 2013-2018 GADS data.

Annual maintenance rates from the 2022 RRA were used in the model. Maintenance was scheduled in one event per unit per year using daily peak load resolution.

Renewable Profiles

Solar and wind profiles for each LRZ for each weather year were taken from the PY23-24 LOLE Study.

External Units (Firm and Non-Firm)

Non-firm external imports were included in the model, following the distribution in Table 3-5 from the PY23-24 LOLE study.

Firm external generation units were also included in the model from the PY23-24 LOLE study. PY23-24 data for the specific units was used for ICAPs, FORs, forced outage mean time to repair, and maintenance rates. Class averages from the F2A data were used to assign fixed operation and maintenance cost, variable operation and maintenance, and heat rates for each external unit.

A.2.2 Future 2A Base Model

The 2027 and 2032 generation portfolios were taken directly from the Future 2A (F2A) output[12], so most assumptions about generation mix match those in the Futures assumptions documents. 250 samples were used per weather year.

Load

F2A load was the basis for load assumptions. Applied Energy Group (AEG) provided the MISO Futures group with annual peak load and annual energy data, that were based upon State Utility Forecasting Group values from the Futures Series 1. The base weather year for F2A load was 2018, and to provide load shapes for weather years 2007–2012 and 2014 – 2021, historical hourly load was gathered and scaled. Next, AEG's electrification, energy efficiency, and demand side management assumptions were adjusted to align days of the week with each historical weather year to develop an electrified load shape for each weather year. Each electrified weather year was then shaped in PLEXOS to reach the F2A zonal peak and annual energy assumptions. Figure A-4 presents two weather year samples for modeled, final load, and Table A-1presents 2027 and 2032 annual energy and zonal peak assumptions.

[12] MISO, *LRTP Tranche 2 – Futures Refresh, Assumptions Book*, Updated April 2023

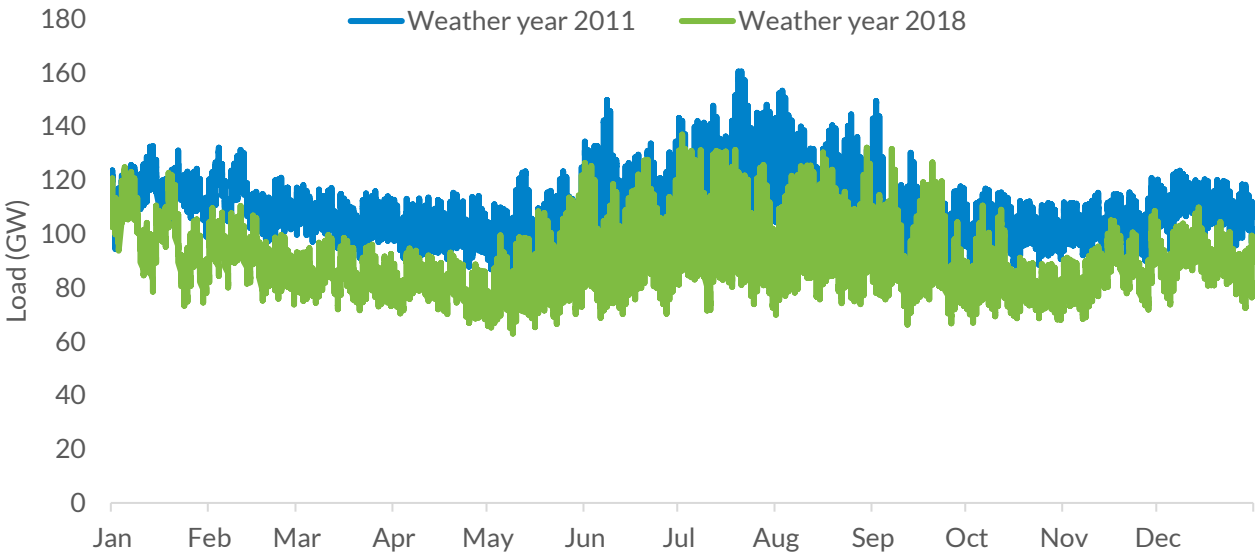


Figure A-4: Sample MISO-wide load profiles for study year 2027

LRZ	Annual Energy (GWh)		Annual Zonal Peak (MW)	
	2027	2032	2027	2032
LRZ 1	114,950	123,255	19,576	20,945
LRZ 2	73,097	80,374	13,268	14,578
LRZ 3	57,446	62,123	10,190	10,843
LRZ 4	55,684	59,790	10,222	10,909
LRZ 5	42,830	45,890	8,655	9,080
LRZ 6	113,354	121,692	19,718	21,207
LRZ 7	118,702	127,942	23,129	24,374
LRZ 8	44,109	45,961	8,527	8,964
LRZ 9	138,646	144,936	22,703	23,773
LRZ 10	24,297	24,950	4,756	4,851

Table A-1. Future 2A annual energy (GWh) and annual zonal peak demand (MW)

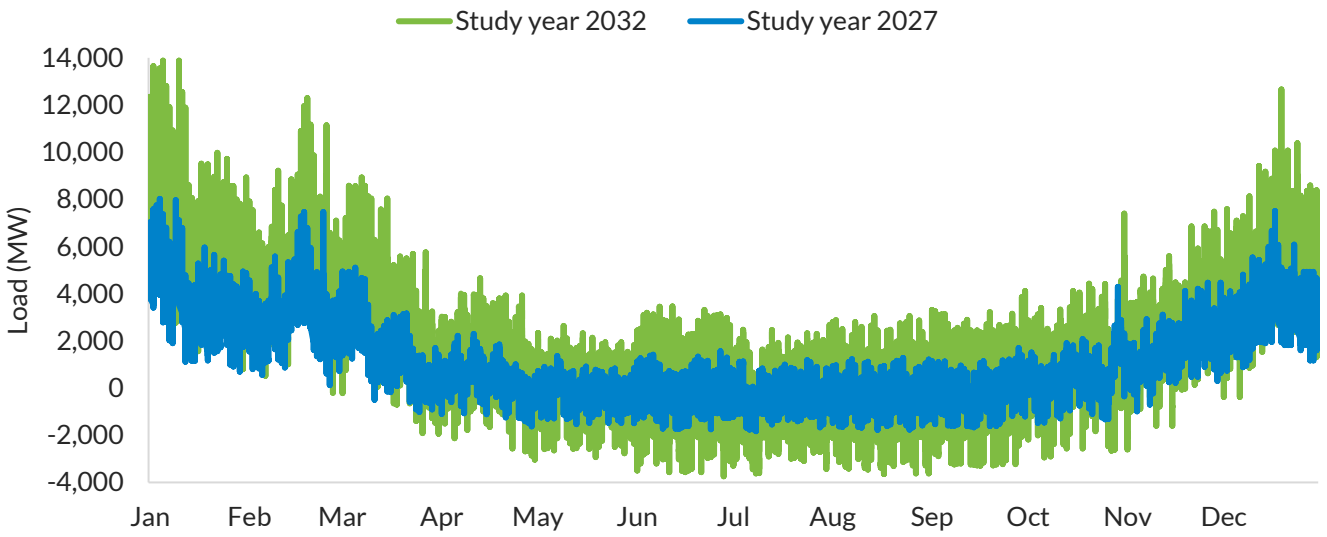


Figure A-5: MISO-wide net electrification (electric vehicle and building electrification load minus energy efficiency)

Generation

Generator capacities and retirement/installation dates were taken from the F2A expansion.

Seasonal FORs were incorporated into the model, along with annual forced outage mean time to repair (MTTR). These values were taken from the PY23-24 LOLE study on a unit-by-unit basis for existing units, and class averages by LRZ were used to assign FORs to future thermal units. FLEX units in the F2A model were assumed to have FORs similar to combustion turbine units.

Annual maintenance rates were incorporated into the model. These values were taken from the PY23-24 LOLE study on a unit-by-unit basis for existing units, and class averages by LRZ were used to assign maintenance rates to future thermal units. FLEX units in the F2A model were assumed to have the maintenance rates of an average gas combustion turbine unit. Maintenance was scheduled in one event per unit per year, matching PY23-24 LOLE study assumptions.

FORs were used and maintenance was scheduled for all unit types except the following:

- Demand response
- DG photovoltaic (PV)
- Interruptible
- Solar PV
- Solar PV Hybrid
- Wind
- Batteries

Additional generator properties were included for thermal units from F2A data. Unit-specific data was used for fixed operation and maintenance cost, variable operation and maintenance cost, heat rates (not used for hydro), and monthly maximum rating values.

Hybrid Units

For hybrid units, 70% of the capacity defined in F2A was assumed to be PV and 30% of the capacity was assumed to be battery. This matches the assumptions used in the 2022 Regional Resource Assessment.

Additionally, there were two constraints for hybrid units implemented in the model. The first is a point of interconnection constraint, which ensures that the solar output and battery output combined cannot be greater than the total hybrid unit capacity at any given time. The second constraint is that the battery portion of the hybrid unit can only charge from the output of the PV portion of that unit.

Specific assumptions relating to batteries, both stand-alone and hybrids, are listed in Table A-2.

Consideration	Modeling Assumption
Battery Capability	Four-hour discharge capability at rated output
Battery Efficiency	Charging efficiency 85% and discharging efficiency 100%
State of Charge	Initial SOC set at 100% and changes as a function of dispatch decisions. Does not reset at the beginning of each day.
Operation	Maximize contribution during loss of load events.
Charging Source – Stand-Alone Battery	Battery can charge from the grid.
Charging Source – Hybrid Battery	Battery component may only be charged from solar PV and not directly via grid.

Table A-2. Modeling assumptions used for stand-alone and hybrid batteries.

Renewable profiles

Hourly wind energy production profiles were gathered from NREL's Wind Integration National Dataset (WIND) Toolkit for the years 2007-2012. Solar data was sourced from NREL's Solar Integration National Dataset (SIND) Toolkit for the same years. Additional data was supplied by Vibrant Clean Energy for the years 2014-2021.

Each wind and solar resource were assigned specific energy-production profiles based on their location, one profile with hourly granularity for each of the 14 years (2007-2012, 2014-2021) studied. Exact latitude and longitude data for future units came from the F2A siting. Exact location data for existing units came from PROMOD when available or was otherwise manually approximated.

Figure A-6 and Figure A-7 present sample MISO-wide solar and wind profiles, respectively, for study year 2027.

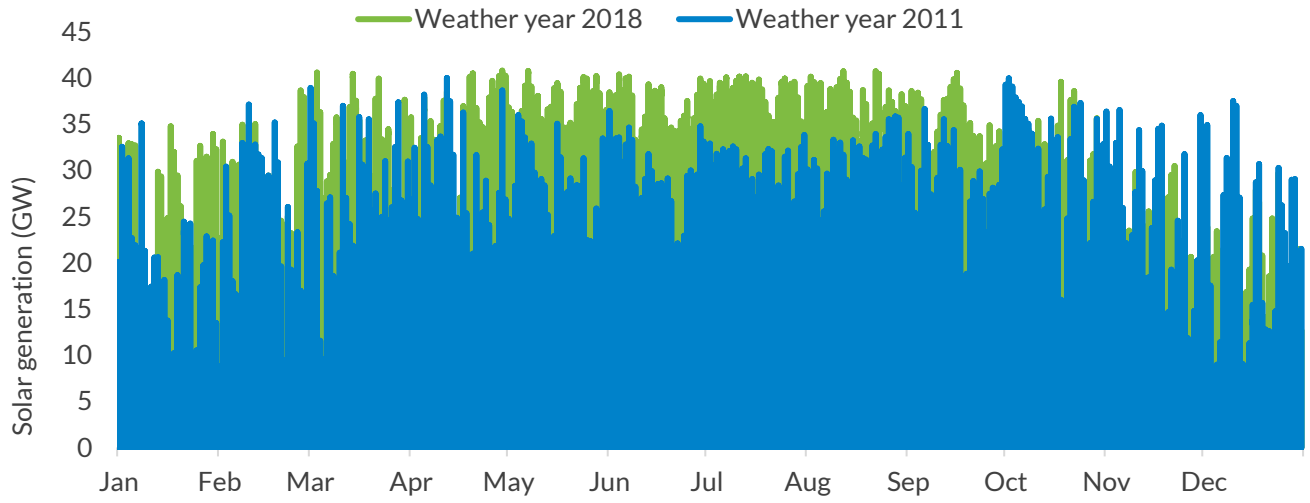


Figure A-6: Sample MISO-wide solar profiles for study year 2027

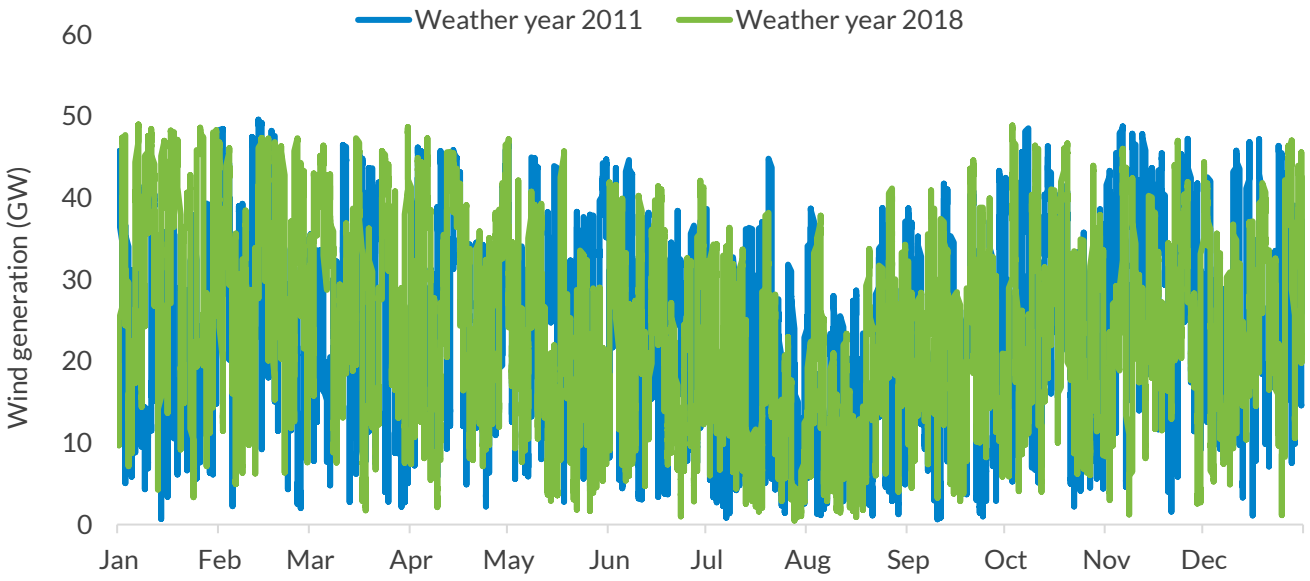


Figure A-7: Sample MISO-wide wind profiles for study year 2027

External Units (Firm and Non-Firm)

Non-firm external imports were included in the model, following the distribution in Table 3-5 from the PY23-24 LOLE study.

Firm external generation units were also included in the model from the PY23-24 LOLE study, and data for the specific units was used for monthly ratings, forced outage parameters (rates and mean time to repair), and maintenance rates. Class averages from the F2A data were used to assign fixed- and variable-operation and maintenance costs, and heat rates for each external unit.

A.3 Scenarios

The model year portfolios were analyzed under three scenarios: business as usual (BAU), enhanced risk assessment (ERA), and flexibility. Figure A-8 summarizes the design behind these three scenarios and how they align with the overall risk factors in the Attributes framework.

- **Business as usual (BAU)**
  - Aligns with base business RA modeling practices and includes cold-weather dependent thermal forced outages
  - *Risk factors:* Availability and Fuel Assurance
- **Enhanced risk assessment (ERA)**
  - Add regional directional transfer (RDT) constraint between MISO North/Central and South, heat rates, fuel prices, and price-responsive storage dispatch to the BAU scenario
  - *Risk factors:* Availability, Fuel Assurance, and Energy Assurance
- **Flexibility**
  - Add generator ramp rates (MW/min) and minimum stable levels to the BAU scenario
  - *Risk factors:* Availability, Fuel Assurance, Rapid Start-Up, and Ramp Up

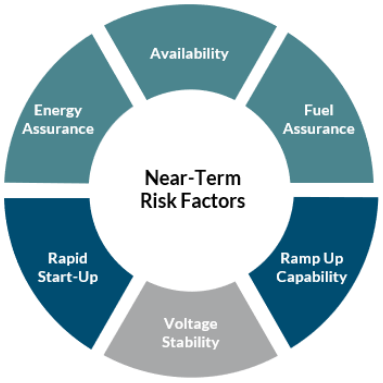


Figure A-8: System adequacy risk factor scenarios

The rest of this subsection introduces the specific assumptions of each scenario.

A.3.1 Business as Usual

In the PY23-24 LOLE study, weather-dependent outages[13] for coal and gas resources were first included in the LOLE study model. Historical MISO GADS[14] data from 2017-2021 was gathered and analyzed to develop forced outages and hourly temperatures by LRZ. From the analysis, which showed a strong relationship between cold temperatures and forced GADS outages for many LRZs, hourly outages in MW were developed for each LRZ and included in the PY23-24 LOLE study model as negative perfect generation.

This analysis implemented the PY23-24 LOLE study outages as hourly MW "adders," with one fixed shape for each weather year. Figure A-9 presents two samples of the MISO-wide weather-dependent outages for the PY23-24 model.

[13] Astrapé Consulting, *MISO Seasonal Inputs for the 2022 LOLE Study*, July 2022.

[14] NERC, Generating Availability Data System

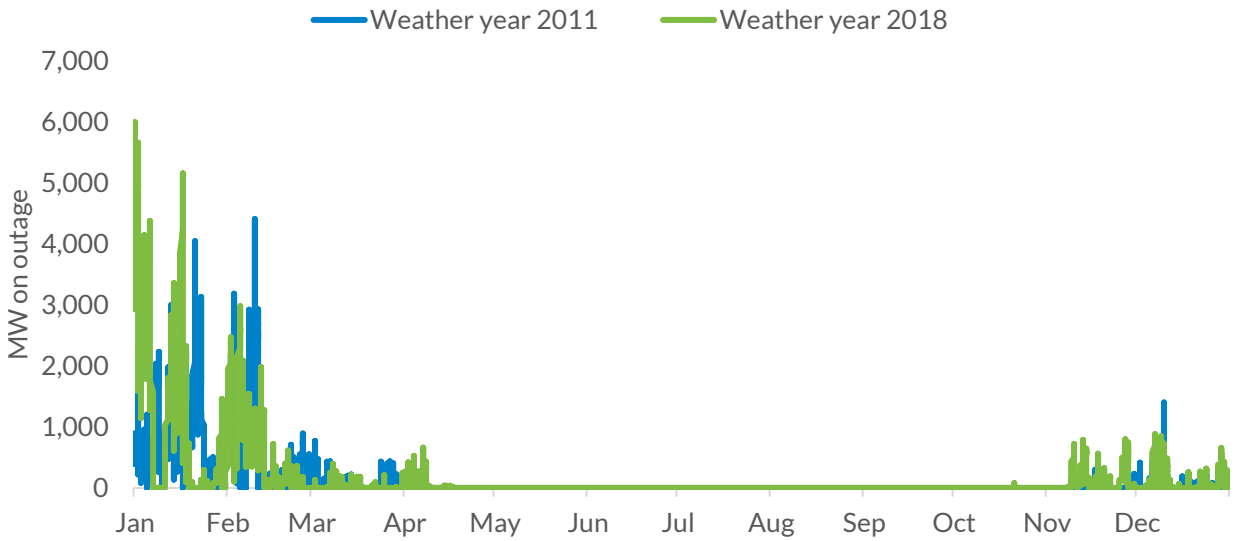


Figure A-9: Sample MISO-wide modeled, weather-dependent outage profiles for study year PY23-24

For the 2027 and 2032 models the hourly outages were scaled based on ICAP in PY23-24 compared to 2027 and 2032. The study represented the Flex units as gas units, so the gas ICAP increased by 65% for 2027 and 70% for 2032, compared to PY23-24. Coal ICAP decreased by 51% for 2027 and 74% for 2032. In all, the hourly outages increased by 35% for 2027 and 32% for 2032, compared to PY23-24.

A.3.2 Enhanced Risk Assessment (ERA)

MISO included the regional directional transfer constraint between MISO North/Central and MISO South in the ERA cases. This constraint places a transfer limit of 3,000 MW from North/Central to South and 2,500 MW from South to North/Central, as shown in Figure A-10. There is no other transmission modeled between individual LRZs.

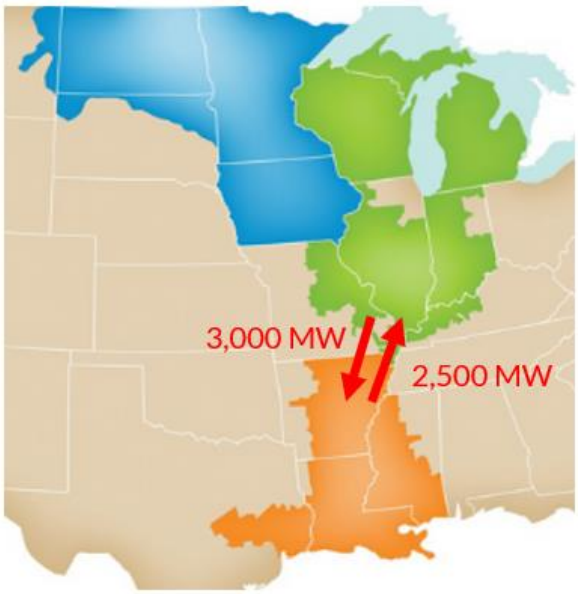


Figure A-10: MISO sub-regions with the regional directional transfer (RDT) constraint highlighted.

Adding transmission constraints complicates the LOLE adjustment process, which is straightforward in traditional copper sheet resource adequacy models. There are multiple ways to reach LOLE targets, depending on 1) whether the LOLE target is enforced at the system level or for each region individually and 2) how adjustments are distributed across the regions. Balance of risk between regions shown in the results section is highly dependent on the selected adjustment method and LOLE target area. Changing the methodology used to adjust may have an impact on simulation results, however, the direction of the results (e.g., shift in risk) are expected to be unchanged.

For the ERA scenario, fixed load adjustment for LOLE analysis was added to each region based on their contribution to MISO coincident peak load. Each region was not adjusted to an independent LOLE target. Instead, all of MISO was adjusted to the 0.1 days/year target, which resulted in a risk profile that was not evenly distributed between the two regions (North/Central and South).

A.3.3 Adequacy-Flexibility Constraint

The goal of this scenario was to further test the BAU model's ability to respond to ramping constraints within the resource adequacy simulations. Both the BAU (without flexibility constraints) and adequacy-flexibility models (with the constraints) were run as rounded relaxation problems for equivalent comparisons.

The historical five year's economic minimum and maximum dispatch and maximum ramping up and down data of thermal units was collected from MISO's historic operation data archive. When commercial pricing node match was available between the unit in operation and the existing unit modeled in PLEXOS, the five-year average of each property was used directly. For the future units and units with missing mapping, a class average was used. To calculate the class average, a class was first defined based on the fuel type of the unit. Among each fuel type, individual units were classified between large, medium, and small categories to form three aggregation groups. PLEXOS units with missing economic mappings were separated into the same classes, first by fuel type and then by their maximum capacity and were assigned the corresponding class average values. Wind and solar curtailment were not considered during the simulation, posing some limitations to the system's capacity to react to net load ramping.

A.4 Results

This subsection summarizes the findings of the analysis. The three scenarios presented in the last subsection were run across study years.

A.4.1 Business as Usual

As expected, LOLE for the PY23-24 model was only present in the summer season with the annual adjustment, and fixed load was added to the remaining seasons to reach a LOLE of 0.01 days/year.

For the 2027 model, LOLE was present in both summer and fall with the annual adjustment, and for the 2032 model, LOLE was present in both summer and winter, which suggests seasonal shifts in risk as the resource portfolio evolves. Figure A-11 presents the loss of load results for the BAU case, showing seasonal loss of load hour frequency from the models, as well as expected unserved energy (EUE) and LOLE for each model. The results show the highest risk in summer for PY23-24, summer and fall for 2027, and summer and winter for 2032.

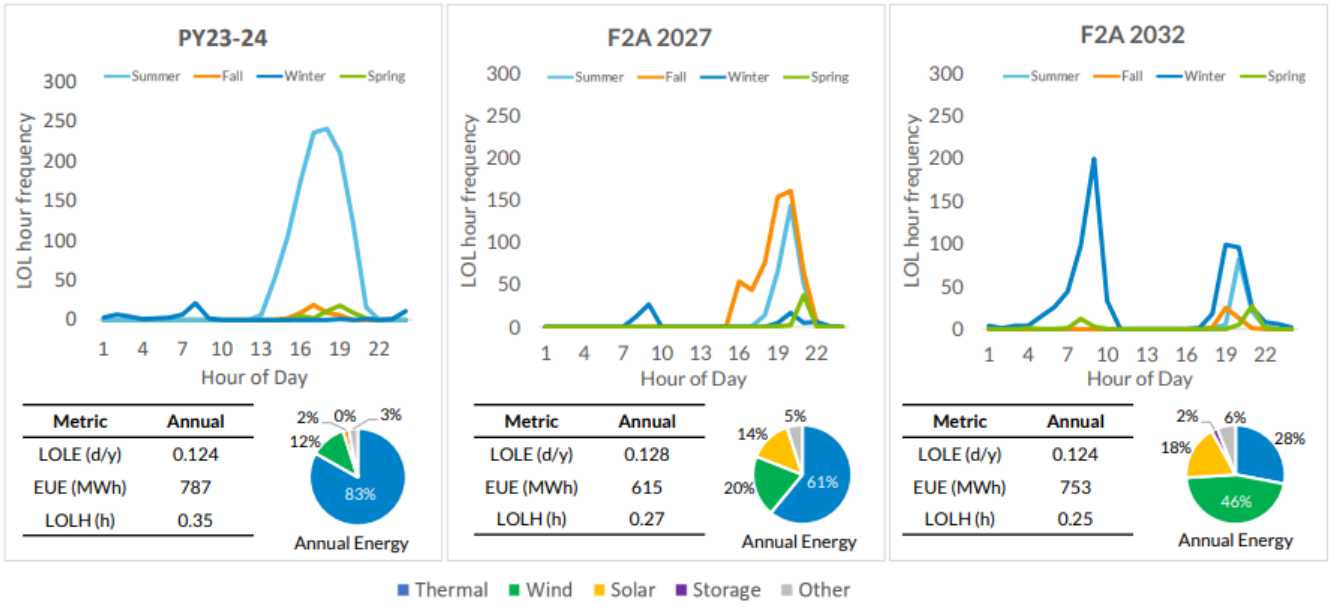


Figure A-11: Loss of load results for the business-as-usual case

DLOL class accreditation estimates were also found for each model year. Due to processing limitations, DLOL results were calculated for wind, solar, storage, and "all other" resource types, which includes all thermal resources and hydro and pumped storage.[15]

Figure A-12 through Figure A-15 present the DLOL results for the summer season, as well as seasonal average diurnal charts which indicate the hours of the season with EUE and average load, load net wind and solar generation, and average wind and solar generation across the season.

Generally, as solar increases in the resource portfolio, risk shifts into evening and early morning hours. At those times solar generation is low, which reduces the solar DLOL across model year portfolios. The charts also show an increase in the "duck curve" shape of net load, as solar increases in the portfolios. Changes to wind DLOLs across model years are mixed as risk shifts into or away from weather years with lower-than-average generation and is less dependent on the time of day of the risk than is solar. Storage DLOLs result in lower values for spring and winter for 2032, as longer-duration EUE events occur which limit the assumed 4-hour ability to fully charge and discharge across the duration of events.

System Adequacy Insight #1:

Accreditation is aligned with the risk distribution, regardless of the underlying sources of risk modeled, and tracks the contribution of individual resources.

[15] All other resource types include nuclear, steam turbine coal, combined cycle, combustion turbine gas, steam turbine gas, flex units, hydro and pumped storage, demand response and interruptible load, solar / storage hybrid, and other.

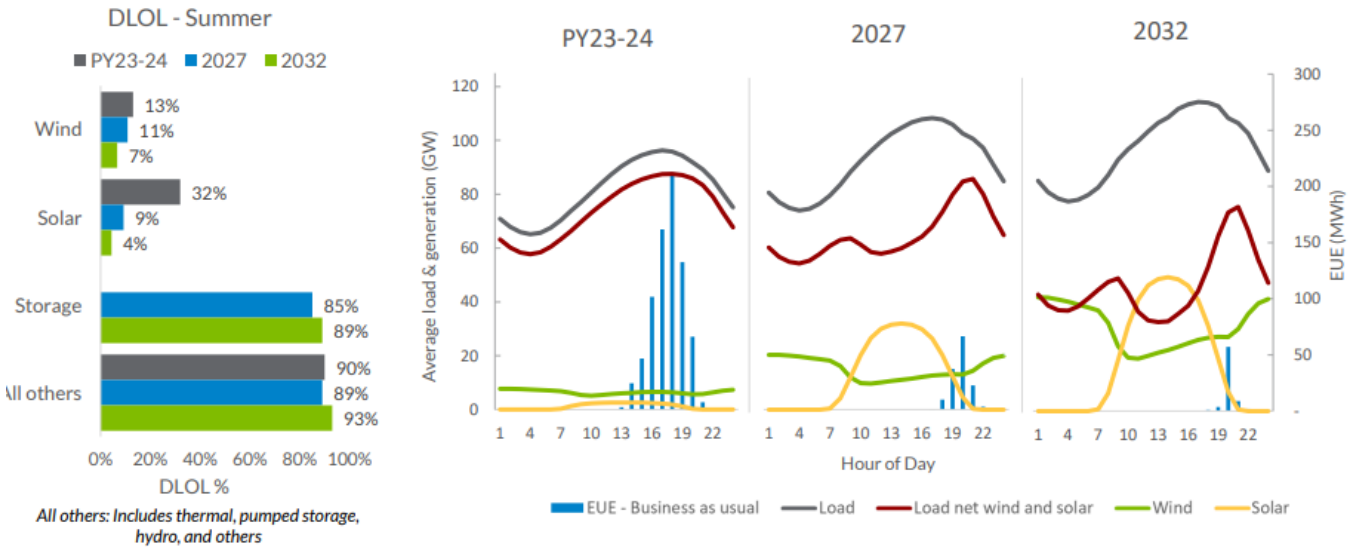


Figure A-12: Summer DLOL results for BAU case

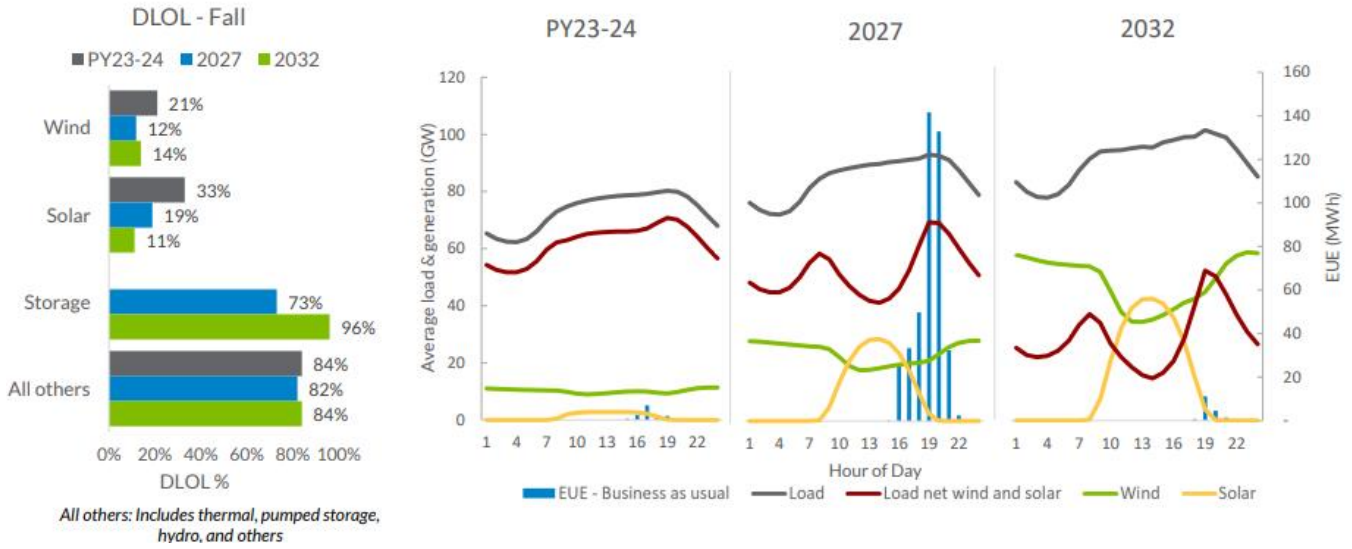


Figure A-13: Fall DLOL results for BAU case

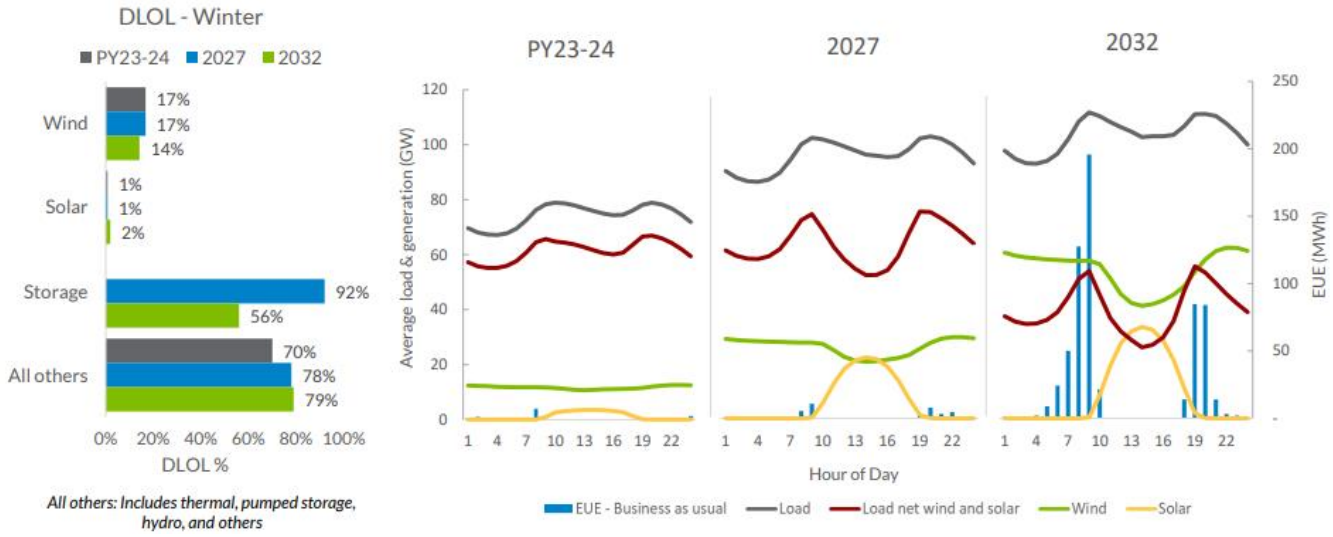


Figure A-14: Winter DLOL results for BAU case

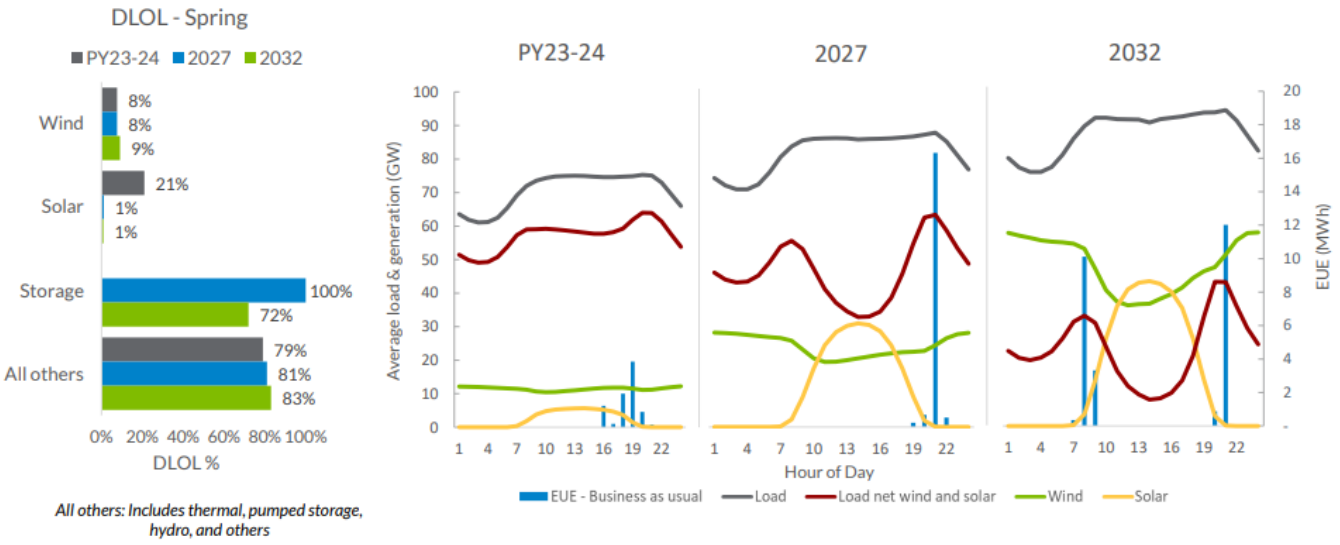


Figure A-15: Spring DLOL results for BAU case

A.4.2 Enhanced Risk Assessment (ERA)

The same adjustments that drove the BAU cases to criteria (0.1 days/year annual LOLE and at least 0.01 days/year LOLE per season) were applied to the ERA cases. The ERA cases, which incorporated the regional directional transfer limits between MISO North/Central and South, had a higher LOLE than the BAU case when at the same adjustment. As shown in Figure A-16, in 2027 LOLE experienced its largest increase in spring and winter when the regional directional

System Adequacy Insight #2:

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

transfer constraint was added, indicating those seasons had the most deliverability limitations between the two MISO regions. Similarly, in 2032 the LOLE increase was concentrated in the winter months for the ERA case, with minimal impacts during the rest of the year coming from the inclusion of the regional directional transfer constraint. The 2032 winter risk increase for the ERA case is driven mainly by deliverability constraints during the 2021 weather year (during Winter Storm Uri).

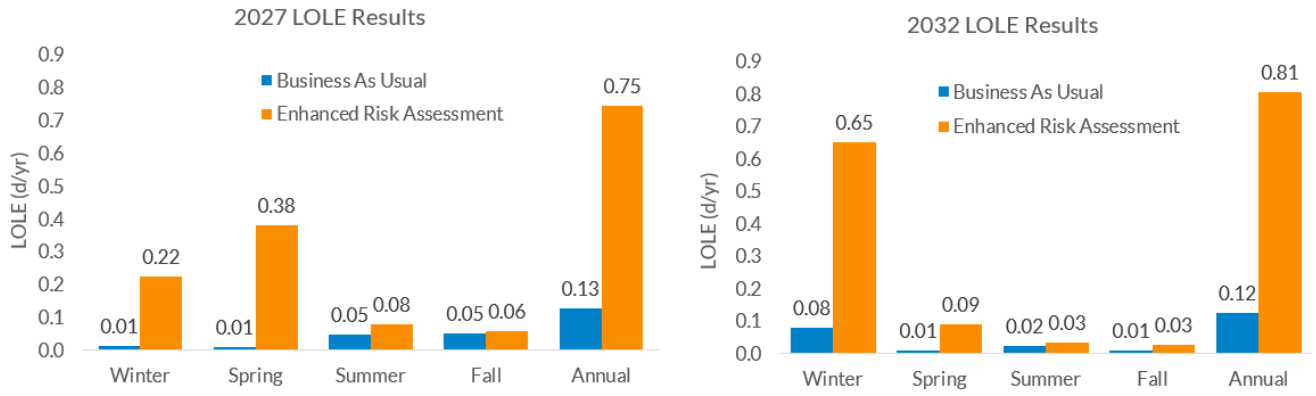


Figure A-16: LOLE comparison between the BAU And ERA cases at the same adjustment

The ERA cases were then adjusted to match the seasonal LOLE values of the BAU cases, to compare the resulting risk profiles and metrics before and after transmission is added in resource adequacy analysis. Figure A-17 shows that in both 2027 and 2032, the ERA case had a smaller EUE value than the BAU case when both were adjusted to the same LOLE target of 0.1 days/year. Loss of load hours (LOLH) did not present a clear trend; LOLH decreased for the ERA case in 2027, but it remained nearly the same between the BAU and ERA case in 2032.

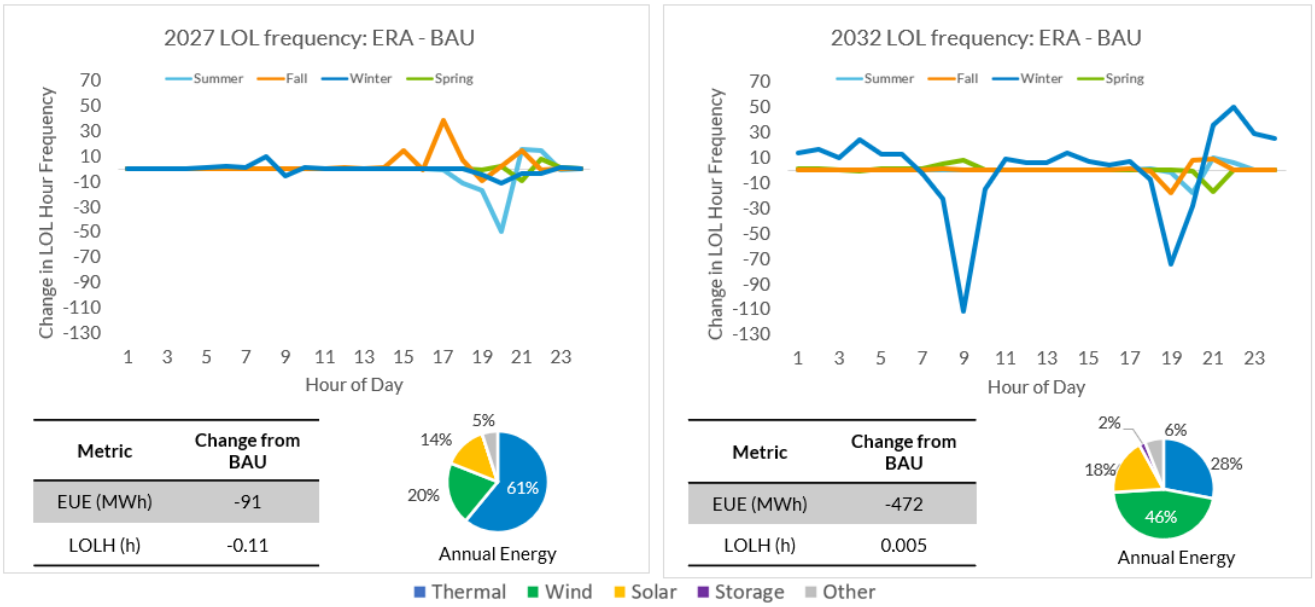


Figure A-17: Loss of load hour frequency and metric changes from the BAU to ERA cases when both are adjusted to the same LOLE targets

The reason for the difference in EUE between the two cases when they are both adjusted to a LOLE target of 0.1 days/year can be explained in part by Figure A-18. For both 2027 and 2032, the BAU cases have a higher average amount of unserved energy per loss of load hour compared to the ERA cases. Additionally, Figure A-19 the ERA cases have a much higher number of unique hours with loss of load across all weather years, despite having a similar LOLH. This indicates that events are smaller in magnitude in the ERA cases and are spread out over a larger portion of the year, rather than a few hours with severe conditions.

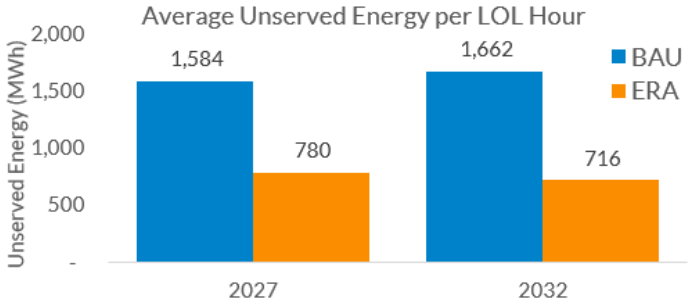


Figure A-18: Average unserved energy per loss of load hour for BAU and ERA cases when both are adjusted to the same LOLE targets

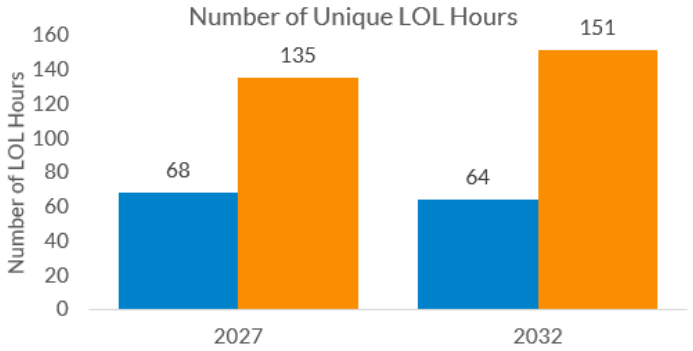


Figure A-19: Number of unique hours across weather years with loss of load when BAU and ERA cases are adjusted to the same LOLE targets

Figure A-20 and Figure A-21 show the accreditation change for each resource class when transmission constraints are added to the model. Wind DLOL increased in almost every season in both 2027 and 2032 from the BAU to the ERA case. This is because most of the wind capacity in the early years of the Future 2A model in the North/Central region, and wind was high in the North during loss of load events in the South in the ERA cases. The details of renewable and storage resource capacity by region for both 2027 and 2032 is shown in Table A-3.

Similarly, storage DLOL decreased in most seasons in the ERA cases because the majority of storage capacity is in the North/Central region and was charging during loss of load events in the South. An example of these two drivers of accreditation changes can be seen in Figure A-22, which isolates a portion of the 2021 weather year that corresponds with Winter Storm Uri — an event that drives a large portion of the LOLE for the 2032 model year.

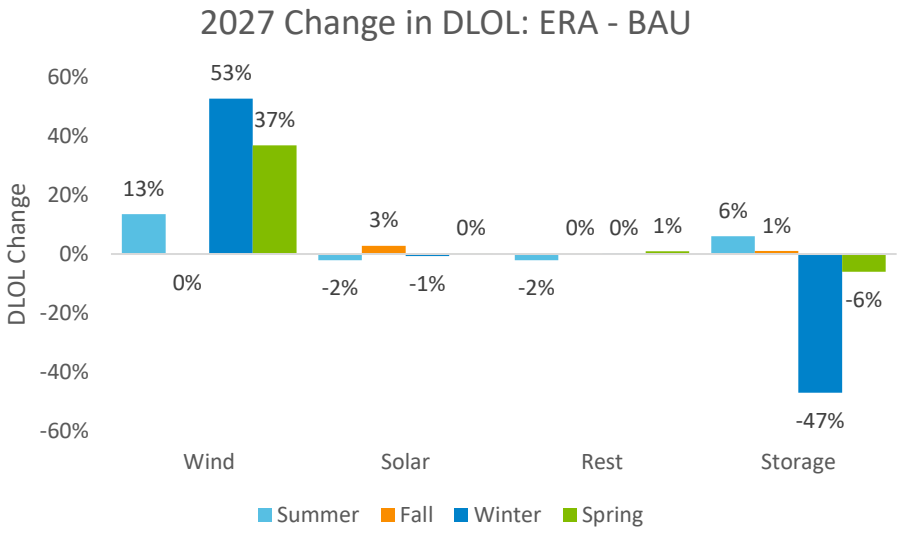


Figure A-20: Change in DLOL by resource class between the ERA and BAU cases in 2027 when both are adjusted to the same LOLE targets

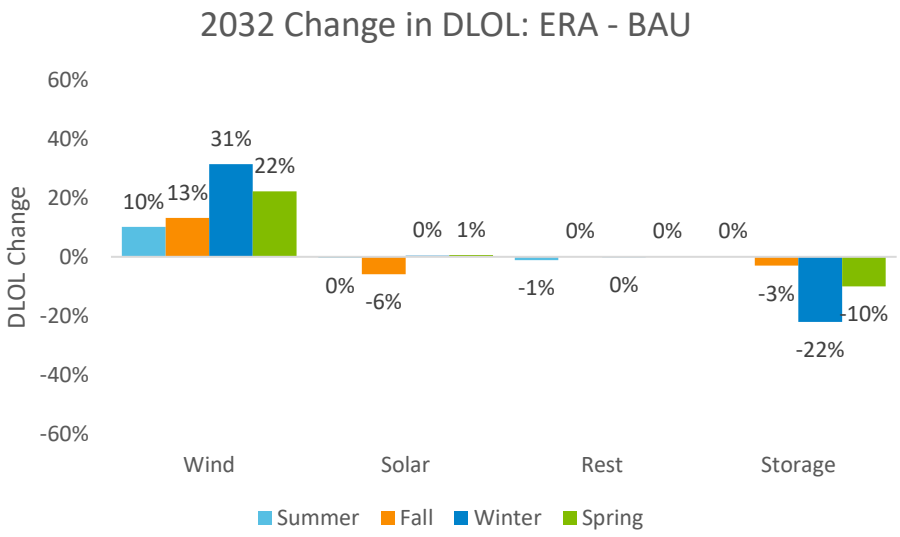


Figure A-21: Change in DLOL by resource class between the ERA and BAU cases in 2032 when both are adjusted to the same LOLE targets

Generator class	2027 ICAP (GW)		2032 ICAP (GW)	
	North/Central	South	North/Central	South
Wind	48.5	1.3	105.1	1.7
Storage	3.6	0.02	6.0	1.3
Solar	28.9	11.9	45.2	18.8

Table A-3. Renewable and storage installed capacities (ICAPs) by region from the Future 2A expansion

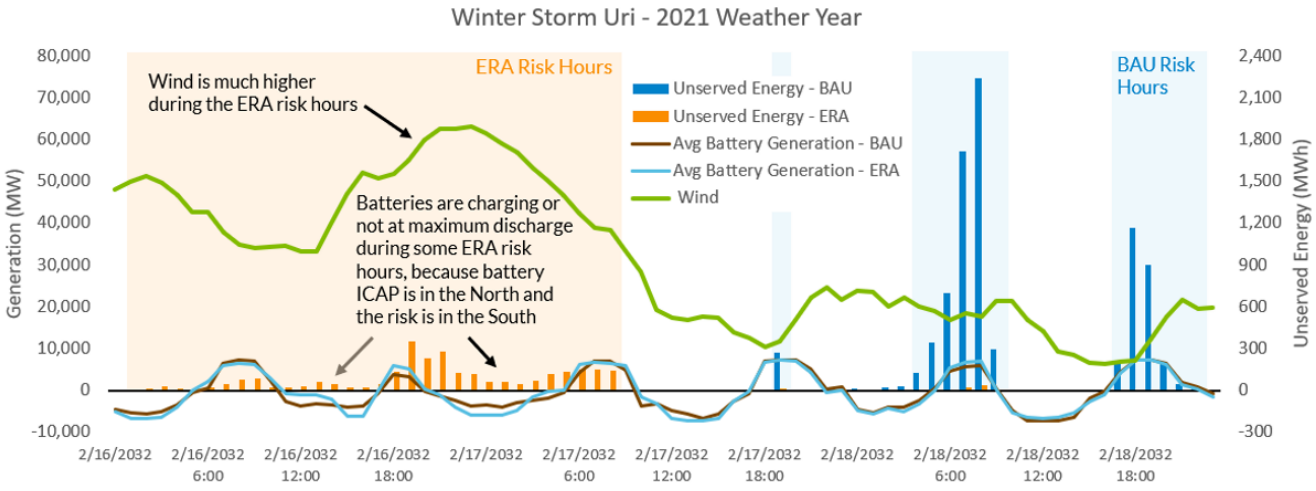


Figure A-22: Example of wind and battery generation and unserved energy from the BAU and ERA cases during Winter Storm Uri in the 2021 weather year simulation

A.4.3 Adequacy-Flexibility Analysis

The adequacy-Flexibility study model used the 2032 BAU model at criteria, i.e., after the LOLE adjustment was completed on a seasonal basis. No additional calibration of the LOLE was applied in this part of the analysis.

System Adequacy Insight #3:

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

The analysis focused on finding the most challenging event the system might experience, by adding further constraints to the period in which the BAU model's adequacy was most tested. In each season, a week with the highest unserved energy amongst all weather years simulated in BAU was chosen as the starting point. Figure A-23 shows the weeks with high EUE present high correlation of net load and net-load ramping, making the period suitable for testing Adequacy-Flexibility constraints.

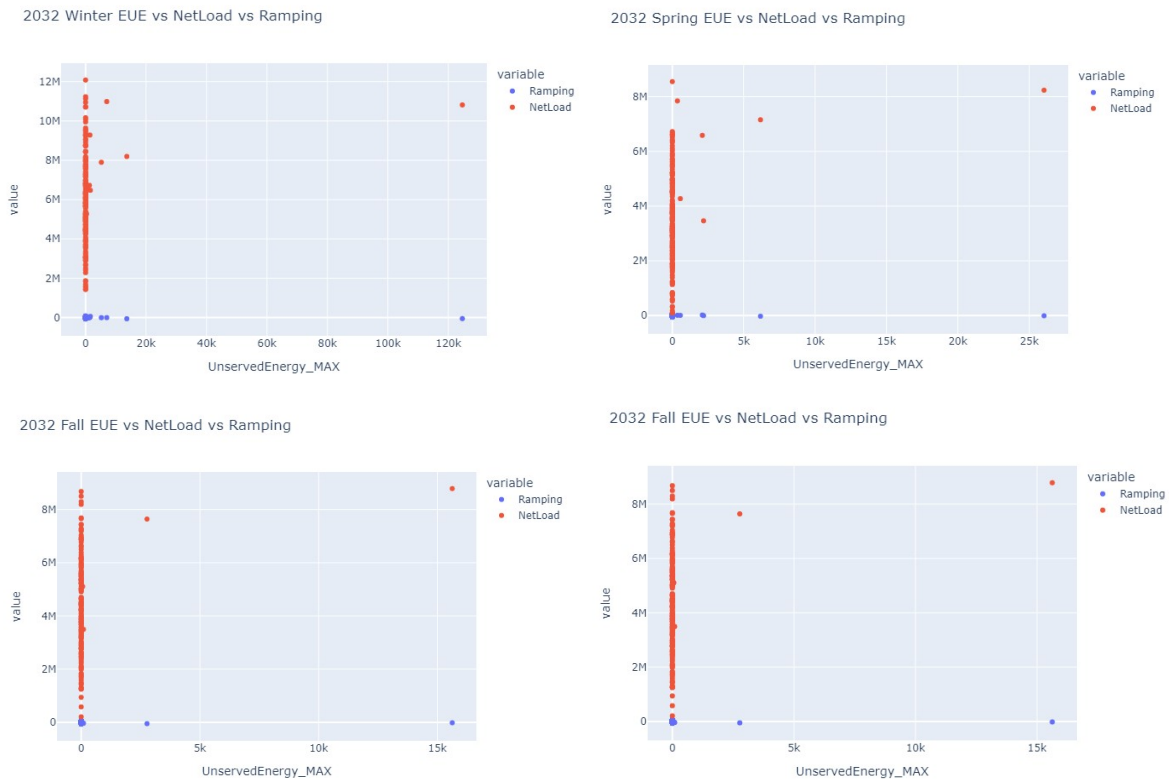


Figure A-23. Weekly unserved energy (MWh) vs net load (MW) and net load ramping (MW) of BAU

Table A-4 shows the final week and weather year chosen for the analysis. The corresponding week of event dates were simulated for the 2032 study year.

Season	Study Year	Weather Year	Week	Dates
Winter	2032	2021	8	February 22-28
Spring	2032	2019	10	March 4-10
Summer	2032	2010	33	August 16-22
Fall	2032	2012	37	September 10-16

Table A-4: Adequacy-Flexibility Analysis Seasonal Simulation Period

No significant changes were observed between the BAU and the Adequacy-Flexibility scenarios for LOLE (number of expected days with events) or LOLH (number of expected hours with events). The EUE of the system showed a significant increase in all seasons, especially in Spring, as shown by Figure A-24. As illustrated in the System adequacy section of the *Attributes Roadmap*, high planned maintenance of thermal units was scheduled during spring and limited the availability of units with higher ramping capability.

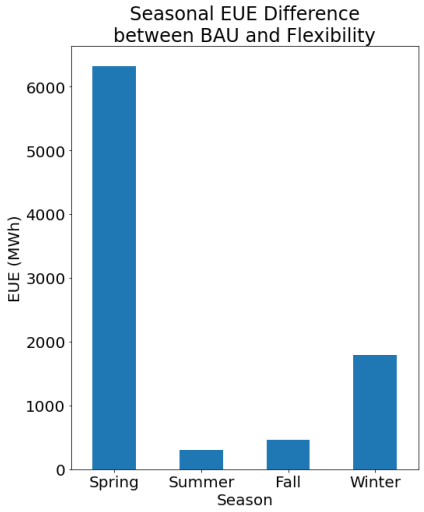


Figure A-24. Seasonal EUE Difference – BAU vs Adequacy-Flexibility

Winter showed the second highest increase in EUE between BAU and Adequacy-Flexibility scenarios. The weather year simulated, 2021, exhibited below average wind generation during its winter, causing longer duration of EUE event. Figure A-25 shows the seasonal comparison of EUE event duration between BAU and Adequacy-Flexibility. Both spring and winter show an increase in longer duration events when the flexibility constraints are applied to the resource adequacy model.

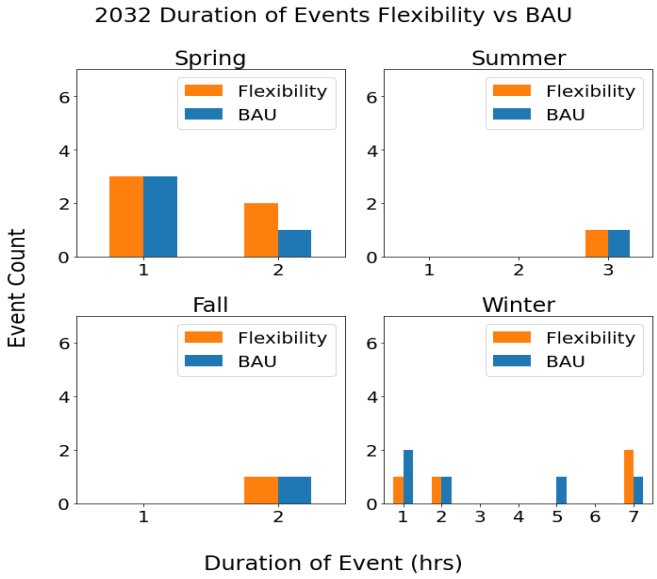


Figure A-25. Seasonal EUE Event Duration – BAU vs Flexibility

Future work may include enable wind/solar curtailment, five-minute simulation, and including operating reserves requirements.

A.5 Conclusions

This section described approaches, tools, and assumptions used in the system adequacy attributes analysis that informed insights and roadmap development. 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?

B.Operational Adequacy

The aim of the operational adequacy analysis was to evaluate MISO's current energy and ancillary services market products and rules, to ascertain whether they are able to procure adequate system reliability attributes, in particular under stressed system conditions. The approach taken was to run a two-stage simulation replicating a simplified version of MISO's two-settlement market, comprising of day-ahead market unit commitment followed by real-time market economic dispatch. This approach was used to analyze both the current portfolio and the future portfolio using MISO's Future 2A scenario. This analysis supports the insights and solution hypothesis presented in MISO's 2023 *Attributes Roadmap*.

B.1 Framework for Market Simulations

B.1.1 Tool

The energy market simulation portion of the system reliability attributes analysis work was carried out using a MISO-enhanced version of the Electrical Grid Research and Engineering Tool (MISO EGRET) that has implemented many of MISO's products, services, and commitment rules. The original EGRET is a Python-based unit commitment and economic dispatch tool that was developed by the Sandia National Lab. MISO EGRET is based on the original EGRET, and was developed jointly with Sandia National Lab, National Renewable Energy Laboratory (NREL), Nexant and Arizona State University under an ARPA-E funded project. For this analysis, MISO developed and tested a new two-stage (day ahead and real time) modeling framework suitable for the system reliability attributes analysis work.

B.1.2 Metric

For this analysis, it was assumed that in the operating timeframe unserved energy is more likely to occur on extreme days than days with normal system operating conditions. Hence the current and future portfolio simulations focused on specific individual days, rather than the whole year. Because only individual days were simulated, this report includes the amount of unserved energy for those days instead of expected unserved energy, which is typically used to assess a longer period such as a season or a year.

For the analysis of the current portfolio, four extreme days were selected from the recent history, one from each season. This provided a good representation across the year and captured seasonal variations. For the future portfolio only winter and summer days were selected because they had the highest potential risks, based on the screening methodology used in this study.

B.1.3 Two-Stage Simulation Framework

It is important to note that the simulation approach was not intended to replay the historical emergency events exactly as they occurred. During those historical events, MISO Operations (acting in coordination with MISO's neighbors) took multiple actions to manage the actual events successfully. Thus, the simulated scenarios will differ from the historical outcomes. This was an intentional modeling choice given that the purpose of these simulations was to analyze "what-if" scenarios and thus to learn key lessons for the System Attributes initiative.

The two-stage simulation framework is presented in Figure B-1 and is organized as follows:

- **Day-ahead stage**: generation unit data such as unit parameters and offers were taken from day-ahead production cases. For renewable units (wind and solar) their economic maximum values were taken from the data of the Forward Reliability Assessment Commitment (FRAC) process. MISO's FRAC load forecast was used rather than market participant demand bids, as is typically the case in the Day-Ahead

Market (DAM), since the aim was to judge the impact of MISO's forecast. The FRAC Net Scheduled Interchange amount was considered (i.e., the net imports from MISO's neighbors). Virtual transactions were excluded.

- **Real-time stage**: data from MISO's look-ahead commitment (LAC) process was used for simplicity. The 96 LAC production cases for the day were combined by taking the first interval from each of them and stitching them together.[16] The small differences between the first interval of LAC and the real-time market cases (such as in outages or forecasts) were ignored. The real-time load was assumed to be known in advance with perfect foresight for the economic dispatch simulation.

The simulations for both current and future portfolios did not consider transmission constraints other than the regional directional transfer limit.[17] This limit is 3,000 MW for transfers from North to South, and 2,500 MW for South to North.

This analysis focused solely on the energy and ancillary services market constructs. Intra-day commitments and other reliability actions usually taken by MISO operators were excluded from this framework.

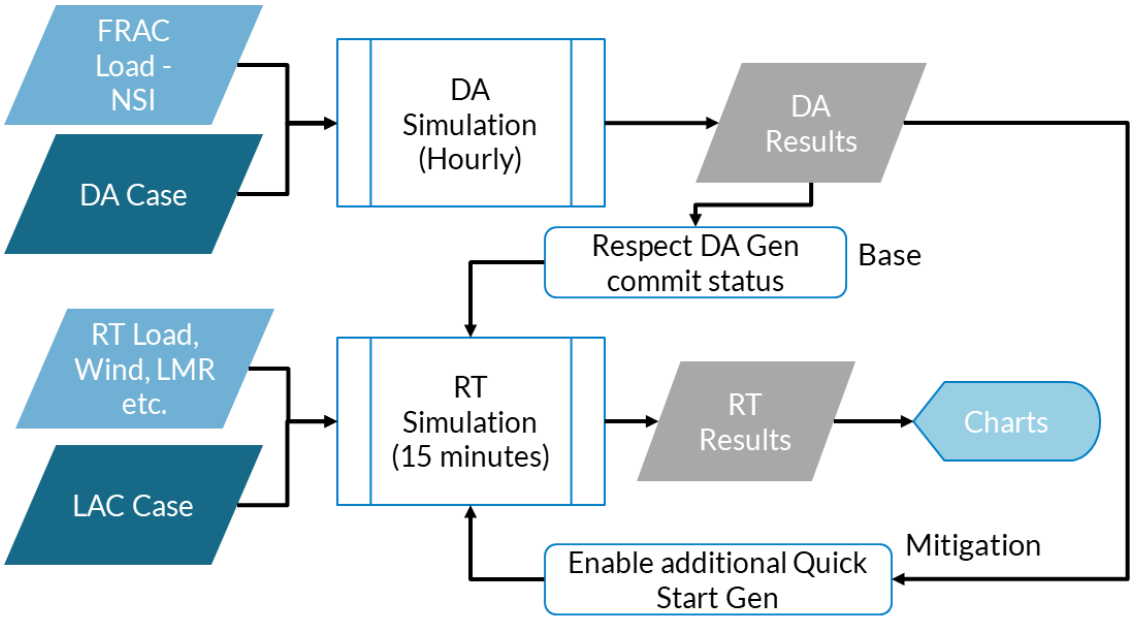


Figure B-1: Simulation framework for energy and ancillary services market

[16] LAC executes every 15 minutes throughout the day on a rolling basis, and the first interval of LAC has a 15-minute span. Thus, we get 96 LAC cases for the whole day.

[17] MISO's Settlement Agreement with SPP and the Joint Parties provides that the upper limit of SPP and the Joint Parties' Available System Capacity is 3,000 MW for flows from MISO North to MISO South and 2,500 MW for flows from MISO South to MISO North. These limits are referred to as Regional Directional Transfer (RDT) Limits.

B.1.4 Screening Methodology for Stressed Periods

The stressed period analysis aimed to find days in the future which have the highest potential for challenging operating conditions. The analysis was based on system net load[18], and associated variability and forecast uncertainty.

The screening analysis assumed that potential flexibility needs are likely to be highest during days with high amounts of net load, net load variability and forecast uncertainty. Net load is defined as load minus renewables (wind and solar PV). Variability is defined as net load changes between time intervals. Forecast uncertainty is defined as the difference between real-time net load and day-ahead forecasted net load.

For each season and future year, the potential stressed days are identified as follows:

- Find the days that contain three or more hours which are at or above the 95th percentile of system-wide net load
- Find the days that contain at least one hour at or above the 95th percentile of net load variability (net load ramp in GW/hour)
- Find the days that contain at least one hour at or above the 95th percentile of net load uncertainty between day-ahead to real-time (net load forecast error in GW)
- Find days in common that have been flagged in Steps 1, 2 and 3 and identify them as stressed days in each season
- The above steps were repeated for each future year, 2027 and 2032
- The days in each future year and season with the highest net load, net load variability and net load uncertainty were identified as the target days for the simulations

B.2 Scenarios

Different types of scenarios were developed to inform the solution hypothesis being considered:

- **Base Case**: this simulated a day-ahead unit commitment for a selected day followed by a real-time economic dispatch. The assumptions described above in the two-stage simulation framework section were used for this scenario. The commitment status for generator units selected in the day-ahead commitment were respected when executing the real-time stage.
- **Stressed Scenarios**: additional stressors were applied assuming the loss of resources that were important for managing the challenging days. This allowed checking whether the day-ahead commitment would have been sufficient to avoid unserved energy. For example, it was assumed that resources such as load-modifying resources or imports etc. were lower than on the given historical day.
- Mitigation Cases:
    - *Mitigation using Quick Start units*: any offline quick start units that were not already committed by the day-ahead process were available to be deployed, assuming perfect foresight
    - *Mitigation using load-modifying resources*: additional load-modifying resources were available to be deployed to mitigate the potential unserved energy, again assuming perfect foresight

[18] Net load is defined as gross minus wind and solar for this analysis.

B.3 Future Portfolio Assumptions

The analysis of the current portfolio used input data from MISO historical records. This section describes the data inputs, assumptions, and methodology for analysis of the future portfolio. The aim of the future portfolio analysis was to evaluate whether MISO's current market products and requirements are sufficient to meet the needs as the generation fleet evolves in the future, and to identify any gaps in the system reliability attributes.

Day-ahead "forecast" load profiles were generated from the real-time "actual" load profiles for future years 2027 and 2032. For wind and solar day-ahead "forecasts" were also generated from the real-time "actual" renewable production for those future years. For both the day-ahead and real-time stages, the net load was obtained by subtracting renewable production from the load and this net load data was used to analyze the potentially stressed periods. Finally, market simulations were conducted for those stressed periods using the MISO EGRET simulation tool developed by MISO.

B.3.1 Data Inputs and Assumptions

For historical time periods both actual and forecast data for load and renewables were available. However, for future years for load only "actual" projections were available, while for renewables "actual" and "forecasts" at the 6 hours ahead (6 HA) timeframe were available. Day-ahead "forecasts" were also needed for the market simulations.

Table B-1 summarizes the sources for the key data inputs needed for the market simulations of the future portfolio, as follows:

- Load: Data from MISO Future 2A was used for projections of future real-time "actual" load. The details of this dataset are described in the Planning Adequacy section (A.3.3).
- Wind and solar: For wind and solar units their locations were determined based on the siting work done under MISO Futures. Next, "actual" real-time and "6 HA forecasts" for renewable unit profiles were generated for these locations using the data supplied by Vibrant Clean Energy.

2027/2032 Input Data	Load	Wind	Solar
Actual	From MISO F2A	From Vibrant Clean Energy	From Vibrant Clean Energy
6 HA Forecast	MISO generated	From Vibrant Clean Energy	From Vibrant Clean Energy
Day-Ahead Forecast	MISO generated	MISO generated	MISO generated

Table B-1: Sources for input datasets needed for market simulation of the future portfolio

The assumptions for the load, renewables, and non-renewable generator units for the future portfolio are summarized in Table B-2.

Consideration	Assumption
Future real-time "Actual" Load	MISO Future 2A load data using the weather year 2018 was considered. The data which includes electrification was aggregated from local balancing authorities (LBAs) to system-level to create annual load profiles at hourly granularity for 2027 and 2032. For the sub-hourly analysis, the hourly profiles were linearly interpolated to generate five-minute granularity load profiles.
Renewable energy production	Offered prices for wind and solar units were assumed to be zero. Wind and solar units were modeled as dispatchable intermittent resources and their hourly generation MW profiles were based on projections made for the future years 2027 and 2032. Wind and solar hourly profiles, based on siting of individual units were created for 2027 and 2032 "actual" generation, using the Vibrant Clean Energy dataset for the 2018 weather year. Also, the Vibrant Clean Energy dataset was used to obtain "forecast" profiles for the six hours ahead timeframe for these units. The hourly profiles were interpolated to generate the five-minute granularity renewable profiles. Finally, all the individual wind and solar profiles were aggregated to the regional and systemwide levels.
Non-renewable generator units	The future portfolio capacity used in the simulations was checked to ensure consistency at the LBA level with the Future 2A capacity for each fuel type. Characteristics (lead time, ramp rate, etc.) for non-renewable generation units were consistent with those from the current portfolio.
Generation outages	Planned and forced outages per season were based on historical average rates for the previous three years. The impact of planned and forced outages in future years 2027 and 2032 were accounted for by derating maximum limits of generation resources for each fuel type.
Net scheduled interchange	The historical real-time systemwide net scheduled interchange profile from a selected event day (Dec. 24, 2022, Winter Storm Elliot) was used for current and future portfolio simulations.
Battery storage operation	Current electric storage resources unit dispatch operation was scaled up consistent with capacities in each MISO region (North/Central, South) based on Future 2A capacities for the future years 2027 and 2032.

Table B-2: Key Assumptions for the Flexibility Assessment

B.3.2 Methodology for Forecast Uncertainty Assumptions

The methodology that MISO used to generate the datasets labelled as "MISO generated" in Table B-1 is as follows:

- The historical day-ahead and real-time load datasets were used to calculate the Total Error in the historical load forecast
- A back-cast dataset that excludes the impacts of weather forecast errors in the load forecast model was used to provide the Model Error
- Assuming that the forecast errors were additive, Weather Error was calculated as the difference between Total Error and Model Error
- The ratio of Weather Error to Total Error for day-ahead load forecast was calculated
- From the available historical actual and 6 HA forecast data, the historical 6 HA load Total Error was calculated

- Using the same ratio of Weather Error to Total Error from the day-ahead case, the 6 HA historical Weather Error and Model Error were obtained
- For future years, MISO assumed that relative Weather Error remains the same, while the Model Error is reduced by 50% (due to assumed improvements in forecasting techniques), i.e., Future 6 HA load Total Error % = Weather Error % + 50% * Model Error %
- This Total Error % is applied to the future actual load profile to get the 6 HA forecast for each of 8,760 hours
- For future day-ahead load forecast error, the steps were similar to those for the 6 HA load forecast case, as described above, i.e., Future day-ahead load Total Error % = Weather Error % + 50% * Model Error %

The historical load Model Error in day-ahead is greater than 6 HA. MISO maintained this relationship in the future data for consistency.

For future day-ahead wind and solar errors, MISO scaled the 6 HA errors using the ratios of the historical day-ahead error to the historical 6 HA error. For example, if in a particular hour of the year the historical 6 HA error is 3% and the historical day-ahead error is 4%, then a scaling factor of 4/3 = 1.333 is applied to scale the future 6 HA error in order to obtain the future day-ahead error. A similar calculation is applied for each of the 8,760 future hours in 2027 and 2032 to obtain the respective day-ahead forecast profiles for wind and solar.

B.4 Results

The increase in renewable (wind and solar PV) penetration in the future fleet results in new patterns in the diurnal net load profiles. The monthly average diurnal net load profiles for the years 2022, 2027, and 2032 are shown in Figure B-2, Figure B-3, and Figure B-4, respectively.

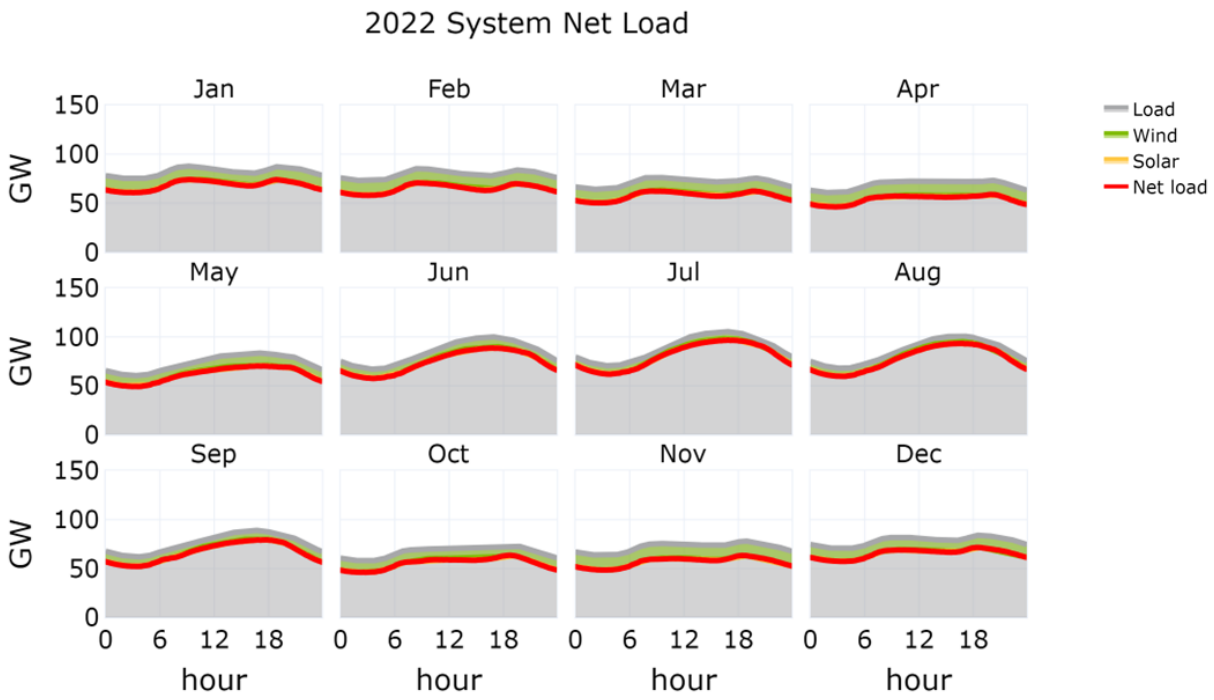


Figure B-2: Monthly averages of diurnal net load components for 2022

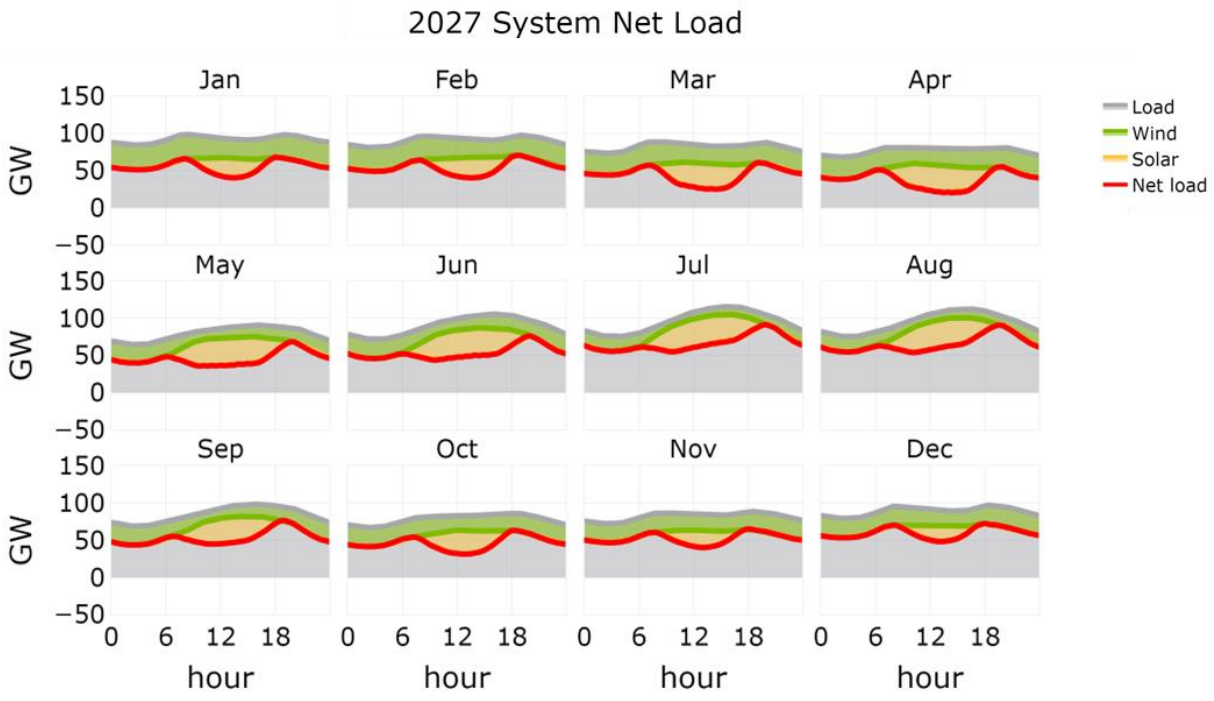


Figure B-3: Monthly averages of diurnal net load components for 2027

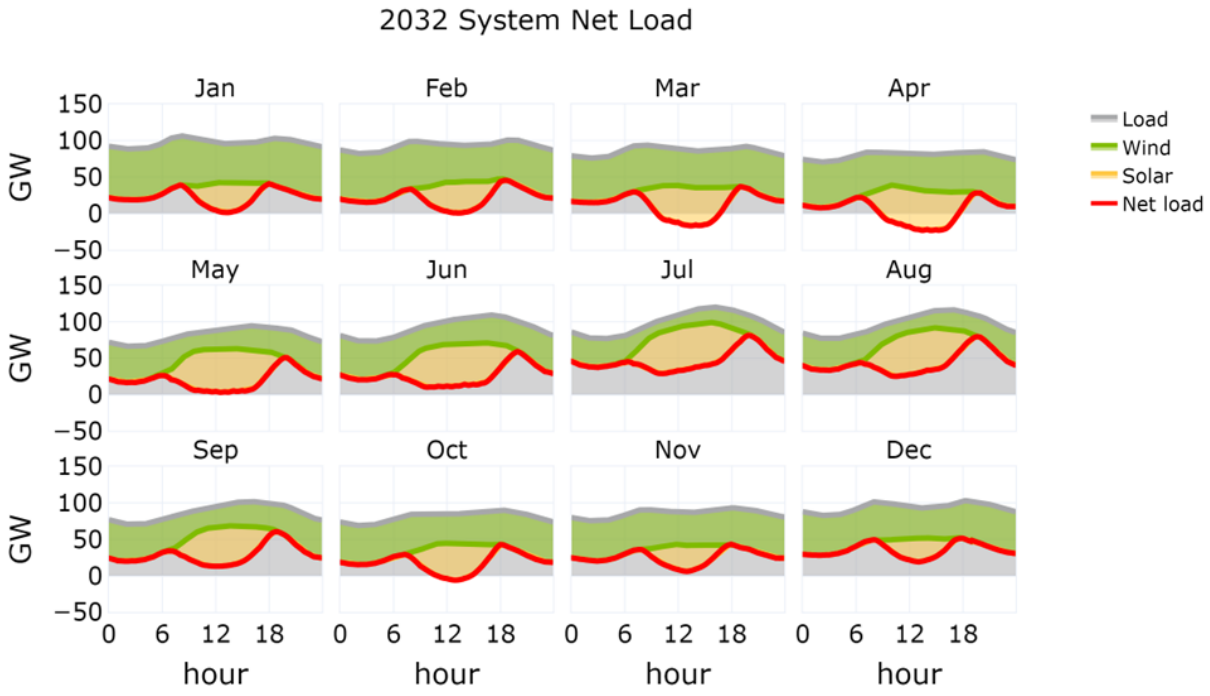


Figure B-4: Monthly averages of diurnal net load components for 2032

As these charts show, with increasing wind and solar penetration the duck-curve shape of net load appears between September and April in 2027 and becomes more pronounced in 2032. Assuming no curtailment of renewables, a number of hours in spring are shown to have negative net load in the afternoon.

Operational Adequacy Insight #1:

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.

Driven by the portfolio evolution and load profile changes, the future net load ramping need is projected to be much higher. The net load ramp needs in both up and down directions (Figure B-5, Figure B-6) are expected to increase by 2027 and 2032. This poses a challenge as resources with fast ramping capabilities will be needed to manage the larger ramps.

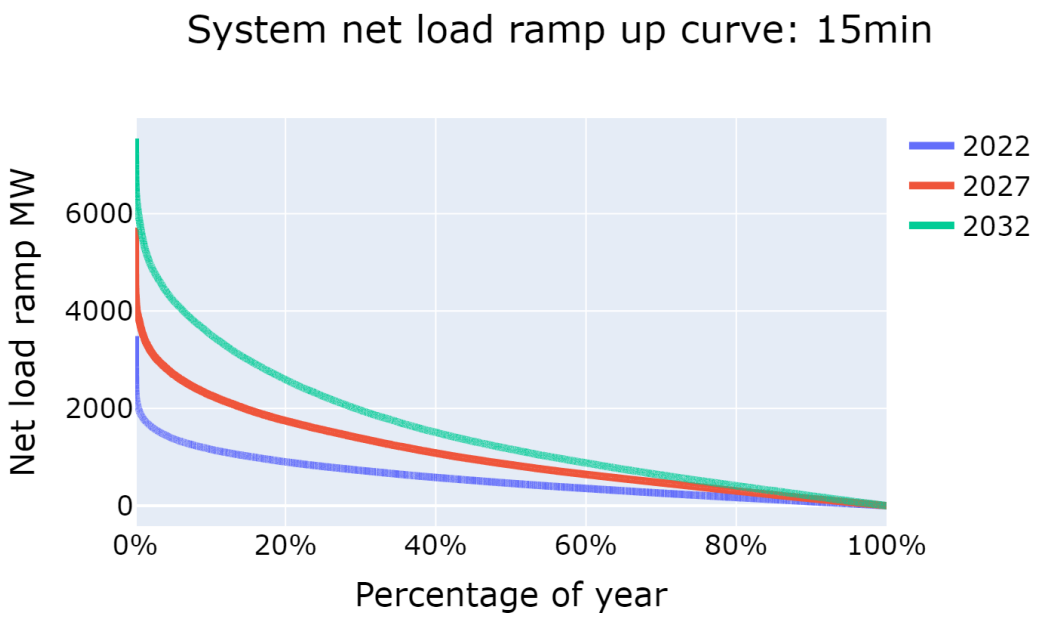


Figure B-5: Systemwide net-load ramp-up duration curve for 15 minutes

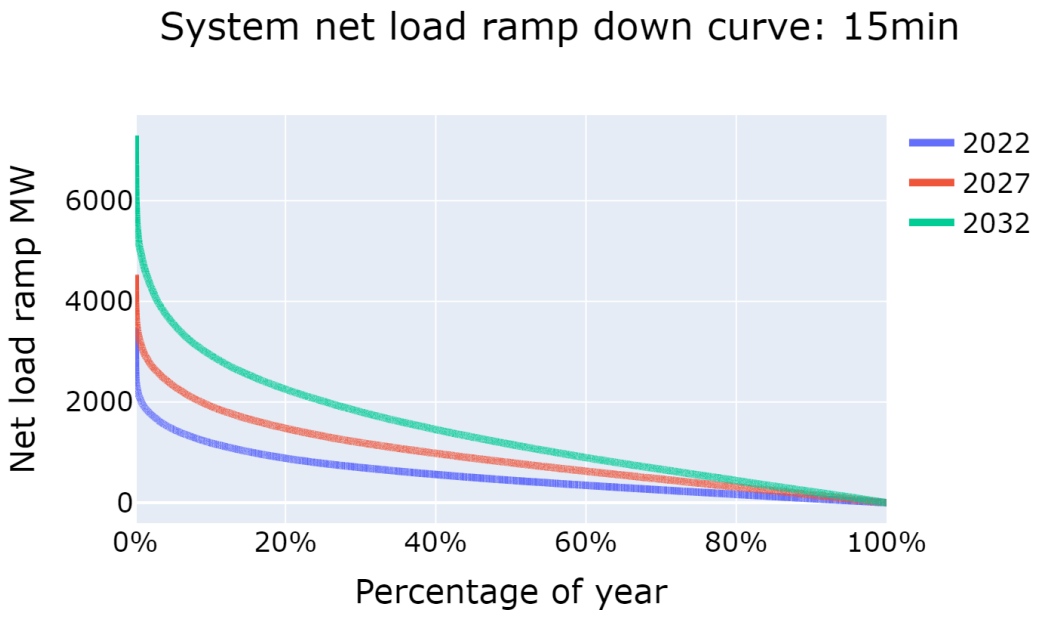
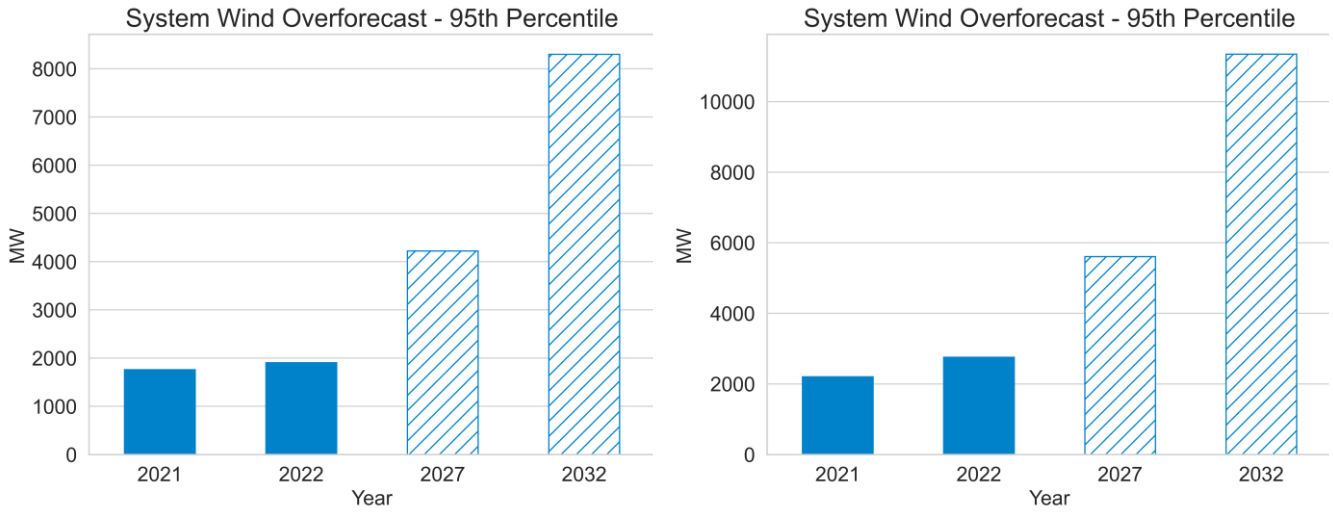


Figure B-6: Systemwide net-load ramp-down duration curve for 15 minutes

Forecast uncertainty for both wind and solar will increase in the day-ahead and short-term (6 HA) horizon from today to 2027 and 2032. For example, the 95th percentile of 6 HA wind over-forecast could increase from 1.9 GW in 2022 to 4.2 GW in 2027 and 8.3 GW in 2032 (Figure B-7a). While the 95th percentile of day-ahead wind over-forecast could increase from 2.8 GW in 2022 to 5.6 GW in 2027 and 11.3 GW in 2032 (Figure B-7b). These estimates assume an improvement in forecasting accuracy.



a) 95th percentile of six-hour ahead wind over-forecast b) 95th percentile of day-ahead wind over-forecast

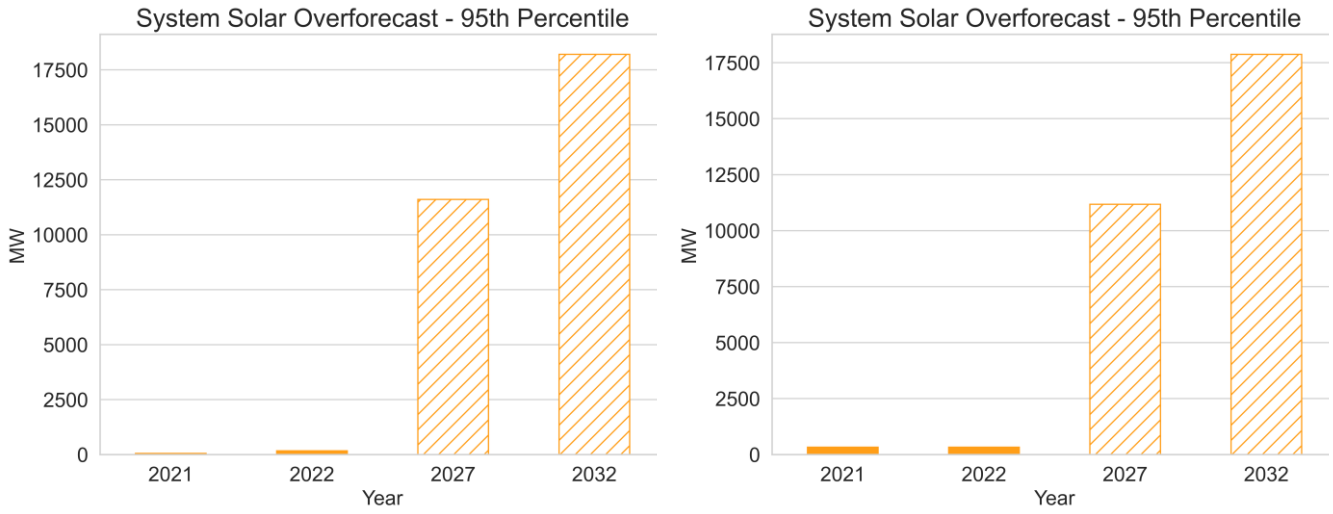
Figure B-7: Wind over-forecast errors in 2021, 2022, 2027 and 2032

Solar PV uncertainty could become larger than wind forecast uncertainty in the future, as solar penetration increases following the trends in Future 2A. The 95th percentile of six-hour-ahead solar over-forecast could increase from 0.17 GW in 2022 to 11.6 GW in 2027 and 18.2 GW in 2032 (Figure B-8a). The 95th percentile of day-ahead solar over-forecast could increase from 0.3 GW in 2022 to around 11.2 GW in 2027 and 17.9 GW in 2032 (Figure B-8b).

Literature on forecasting experience shows that shorter forecast lead times are correlated with lower forecast errors.[19] However, this was not the trend observed in MISO for 2021 and 2022, with the mean short-term solar forecast error being comparable or even larger than the day-ahead error. This analysis projected current MISO statistics for future years 2027 and 2032, so the trends did not match the expectation from literature. This could change in the future as the penetration of solar in the MISO footprint increases.[20]

[19] CAISO, "Day-ahead market enhancements discussion: Role of forecast uncertainty" Presented at CAISO's Market Surveillance Committee Meeting, Aug 27 2021.

[20] Penetration of solar PV in MISO footprint in 2021 and 2022 was much smaller than in California ISO (CAISO).



a) 95th percentile of six-hour ahead solar over-forecast b) 95th percentile of day-ahead solar over-forecast

Figure B-8: Solar over-forecast errors in 2021, 2022, 2027 and 2032

Figure B-9 shows the potential stressed days in 2027 and 2032 flagged by the screening method. Those days are highlighted as the cells in the calendar chart and are represented with their highest net load values (in GW).

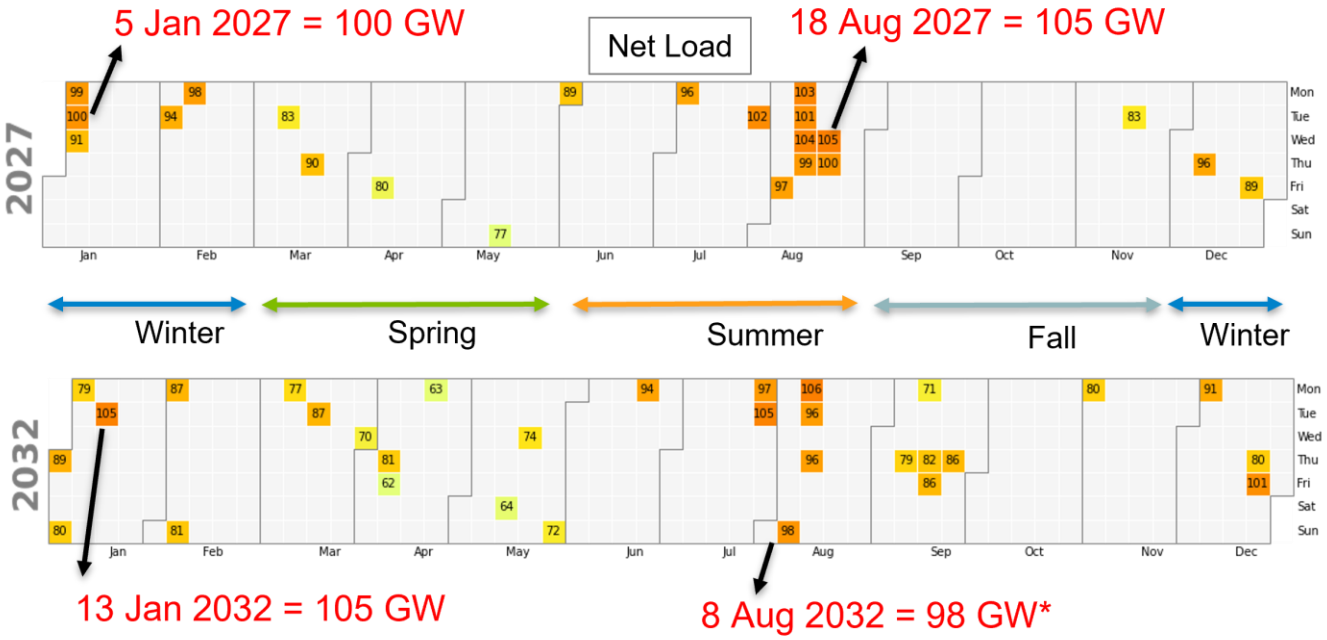


Figure B-9: Calendar chart of potential stressed days in 2027 and 2032

Figure B-10 presents a bar chart containing the actual maximum generation alert/warning/event days from 2022, as well as the potential stressed days from 2027 and 2032, grouped by the season. The operational risk in the future gets more spread out across the year as risky days begin to show up in the shoulder seasons. Additionally, the total number of risky days increases in the future.

Operational Adequacy Insight #2:

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.

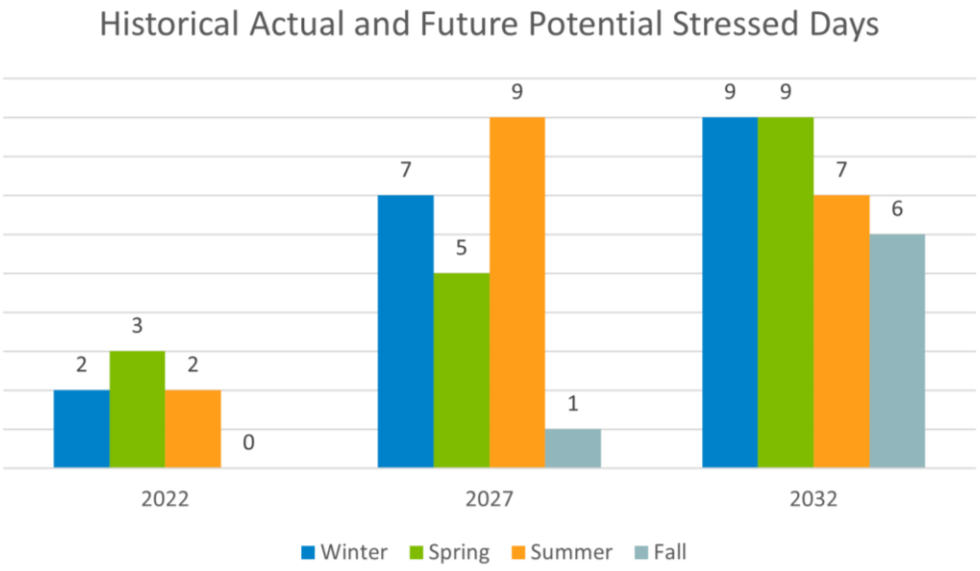


Figure B-10: Historical events and future potential stressed days by season

Figure B-11 shows the simulation results of various scenarios for the target potential stressed day for the event in winter of 2027. For the base case scenario (assuming no operator actions) the day-ahead commitment was inadequate to meet the real-time load, resulting in a small amount of unserved energy. Three individual stress scenarios are considered:

- A 50% drop in wind production throughout the day
- The removal of external imports (MISO rather ends up exporting power)
- A high-impact single gas pipeline outage

Operational Adequacy Insight #3:

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.

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 three stress conditions occur on the same day.

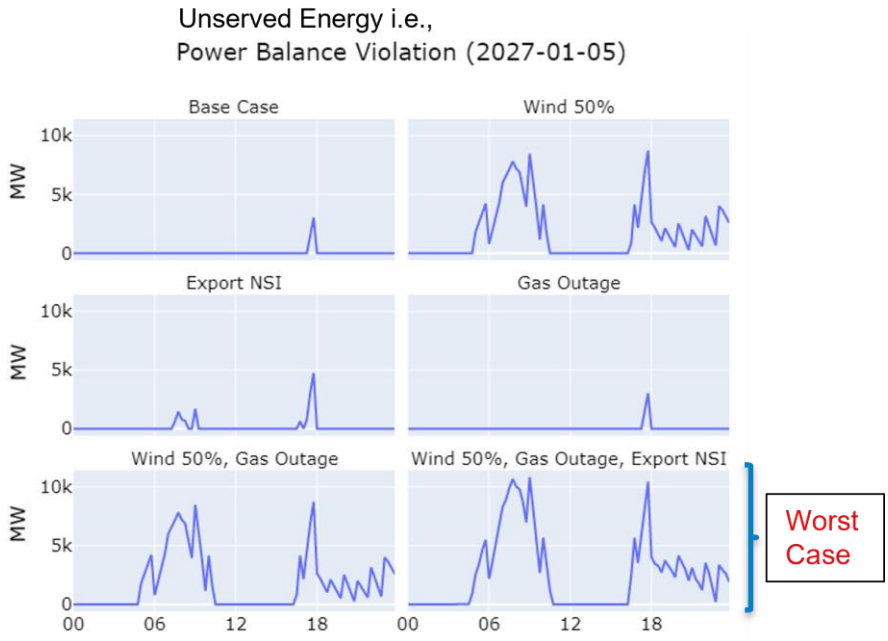


Figure B-11: Simulation results for base case and stressed scenarios for the winter 2027 event

Figure B-12 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 according to their lead time, starting with the fastest group (i.e., "quick 20 minutes"), followed by units with increasing lead times (e.g., up to 60 minutes or 120 minutes). The unserved energy is completely mitigated with units of lead-time of up to 5 hours.

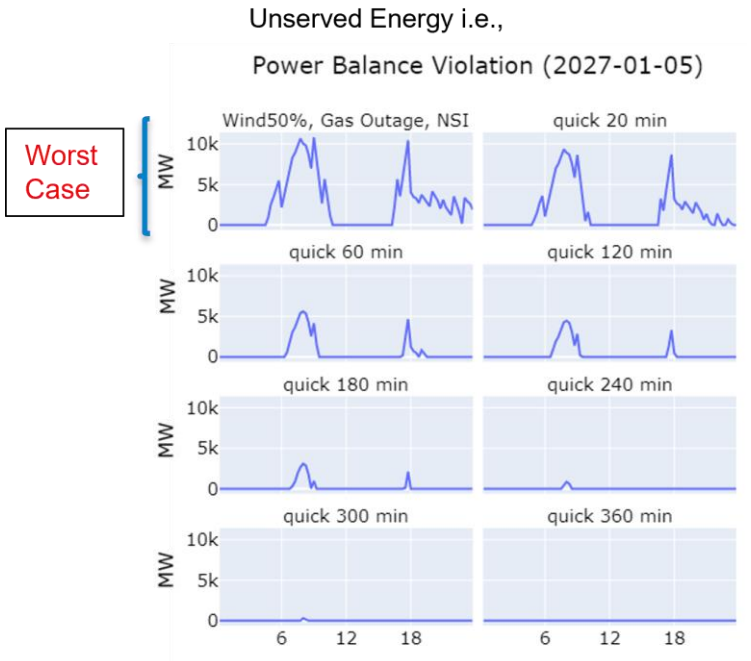


Figure B-12: Simulation for worst stress case and mitigation using quick start units for the winter 2027 event

Figure B-13 shows the available capacity of quick start units for different lead times throughout the day for the winter 2027 target day. Quick start capacity needs to be available during the high-risk hours to mitigate the unserved energy. This illustrates the need for resources to be available at the right time, and not just in an aggregate sense. MISO needs improvements in its commitment processes to ensure that adequate resources are always available to manage unanticipated changes in system conditions. This is relevant given the growing uncertainty in net load as the penetration of renewable generation increases.

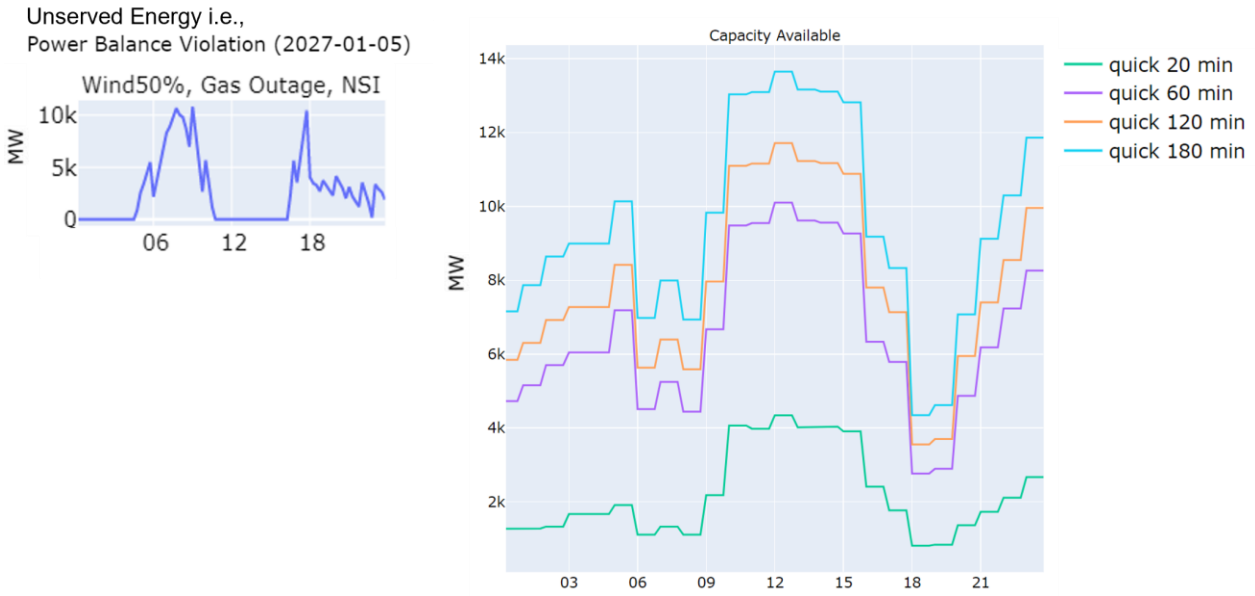


Figure B-13: (Left) Unserved energy result for the worst case of the winter 2027 event; and (Right) total capacity of quick start units for different lead times in minutes (≤20 min, ≤60 min, ≤120 min, ≤180 min)

B.5 Conclusions

This technical appendix describes approaches, tools, inputs, and assumptions used in the operational adequacy attributes analysis that informed the insights and the development of MISO's 2023 *Attributes Roadmap*. The insights and results were directionally indicative as to whether enhanced market practices or new products are needed to mitigate the risks in the operating timeframe.

C.Voltage Stability

This section in the technical appendix provides supplemental information on the analysis described in the System Stability section of MISO's 2023 *Attributes Roadmap*. Before addressing the analysis, voltage stability is defined within the broader stability landscape and an overview of MISO's current practices are provided. The context and current state information is not intended to be comprehensive, but rather to provide some information useful in understanding how MISO's voltage stability analysis relates to previous findings and existing practices.

C.1 Voltage Stability Definition

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.[21] It depends on the ability of the combined generation and transmission systems to provide the power requested by loads.[22] Voltage stability is often thought of as load-driven rather than resource-driven, though resource characteristics affect voltage stability outcomes.

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). Several factors can cause voltage instability, such as insufficient reactive power support, excessive loading, loss of transmission lines or generators, or inadequate voltage regulation. During the northeastern U.S. event in 2003, voltage instability resulted after multiple line tripping contingencies caused voltage fluctuations and reactive power deficiencies, in turn causing generators and transformers to trip or malfunction.

Voltage stability is one family of power system stability issues that can arise on the grid. Figure C-1 shows a taxonomy often used within engineering technical papers on the matter.[23] Voltage stability has the additional dimensions of small and large disturbance and short- and long-term timescales, described in greater detail below.

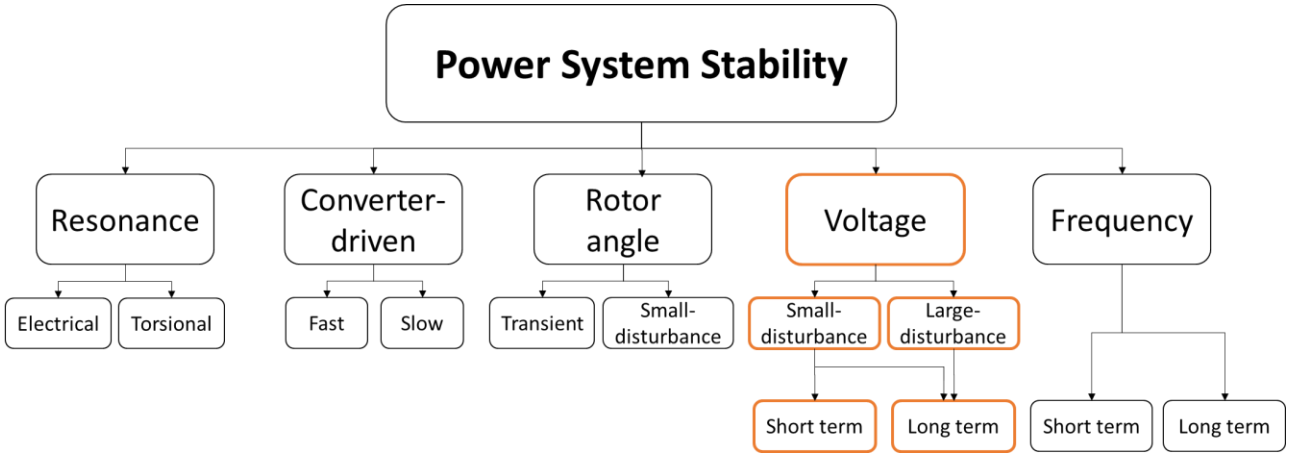


Figure C-1. Taxonomy of power system stability considerations

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

[22] T. Van Cutsem and C. Vournas, *Voltage Stability of Electric Power Systems*. Norwell, MA: Kluwer, 1998.

[23] 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.

Two different disturbance types are relevant for the voltage stability definition within Figure C-1.

- **Small signal** voltage stability refers to the ability of the power system to maintain stable voltage under small perturbations around the expected operating point. For instance, small increases or decreases in line active power loading and reactive power flows.
- **Large signal** voltage stability refers to the ability of the power system to maintain stable voltage following a large system disturbance, such as a line fault.

Small signal analysis can use linear system models whereas large signal analysis must account for non-linearities associated with large system disturbances.

For each of the disturbance types, two timescales apply within the voltage stability taxonomy illustrated in Figure C-1:

- **Short-term** typically considers effects of load dynamics short circuits near load, often worst case (e.g., motors stalling, electronically controlled load tripping). The timescale is typically on the order of seconds.
- **Long-term** (e.g., several minutes) typically considers progressive reductions in voltage under maximum power transfer limits, often during contingencies (e.g., tap changers, generator current limiters). The timescale is often on the order of minutes.

C.2 Current State of the MISO system

MISO has performed detailed planning analysis of future system stability impacts through long-range studies like the Renewable Integration Impacts Assessment. Further, stability analysis is included in MISO's standard MTEP planning process. Operational analysis is also performed to evaluate risks in near real-time based on actual system conditions, an analysis which is being expanded based on recent NERC standard revisions. The following sections describe past and current efforts underway at MISO.

C.2.1 Renewable Integration Impacts Assessment

MISO's Renewable Integration Impacts 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.[24] These challenges could arise when renewable resources serve roughly 30% 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.[25] In addition to the voltage stability challenges emerging earlier in the energy transition, the anticipated capital cost to mitigate the issues is expected to be the highest of all stability related challenges studied in RIIA. Figure C-2 recreates the RIIA report's summarized ranking of dynamics issues, with information on impacts, relevant penetration levels, and relative mitigation costs, among other factors.

[24] MISO, *MISO's Renewable Integration Impacts Assessment (RIIA) study*. Summary Report. February 2021.

[25] MISO, "Future 2A Expansion and Preliminary Siting", Presented at MISO's LRTP Workshop, March 10, 2023.

Area of stability	Ranked concern	Performance metric	Impacts	Possible mitigations	Concerned MISO group	Issue first seen	Impact of renewable penetration	Capital cost share to mitigate
Inverter-based stability and voltage stability	1. Transient voltage stability in weak areas	Short circuit ratio, undamped voltage and current oscillations, interactions between the controls of equipment	Local area, observed at many substations system-wide	• Control tuning • Synchronous condensers • STATCOM • HVDC	EP*, GI†	30%		
Frequency stability	2. Frequency response	Frequency nadir, rate of change of frequency (RoCoF), NERC BAL-003 obligations	Interconnection wide	• Additional planned online headroom • Batteries	Operations	50%		
	3. Small signal stability	Damping ratio of low frequency oscillations	Interconnection wide	• Must-run units with power system stabilizers • Specially tuned batteries	EP*, Operations	30%		
Rotor-angle stability	4. Transient rotor angle stability	TO's local planning criteria, NERC criteria	Local area	• Faster protection schemes • Transmission facilities	EP*, GI†	50%		–

*EP: Expansion Planning
†GI: Generator Interconnection

Figure C-2. RIIA summary of dynamic concerns

The RIIA analysis used a screening method based on short-circuit ratio (SCR) to identify "weak grid" areas and system locations with low available short-circuit current, which is an indication of potential stability issues. However, the determination of the type and magnitude of stability challenges necessitates detailed dynamics analysis using different tools such as positive sequence dynamics tools (e.g., TSAT, VSAT).

RIIA's detailed dynamics assessment showed the need for stability-related mitigations, another term for solutions that largely targeted STATCOMs, synchronous condensers, dispatch adjustments, HVDC, HVAC, batteries, and controls tuning. Small amounts of other solutions were contemplated. Figure C-3, reproduced from MISO's RIIA report, shows the level of complexity introduced by each solution for the renewable penetration milestones evaluated. In this context, complexity can roughly be treated as a proxy for investment needs. Grid-forming controls for inverter-based resources was not a solution that was considered in the RIIA study.

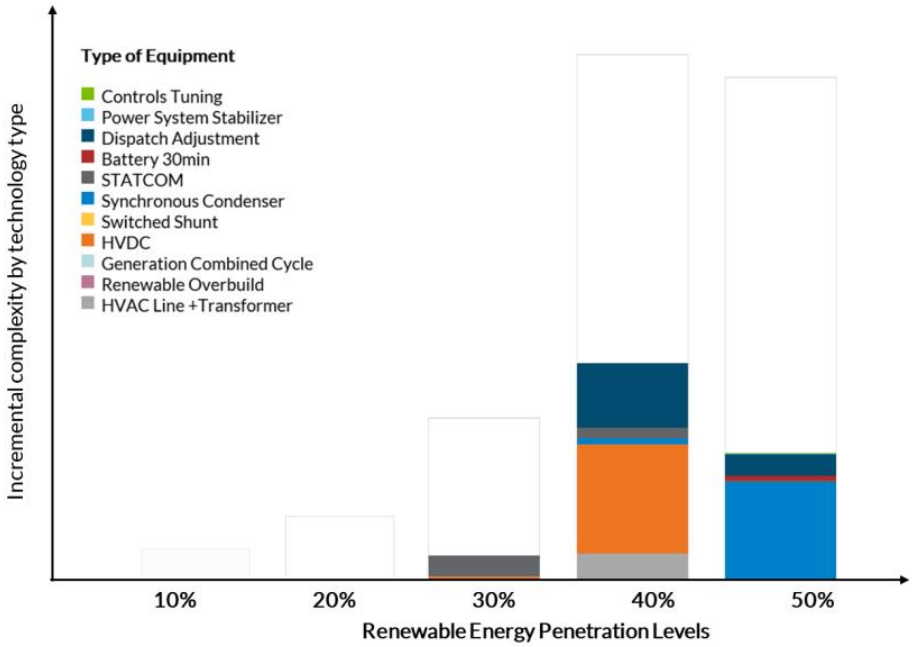


Figure C-3. RIIA dynamic stability solutions — incremental complexity by technology type for renewable penetration milestones

C.2.2 Planning

MISO's voltage stability analysis for reliability planning selects specific transfer scenarios, based on stakeholder and system operator input, with the goal of identifying potential reliability risks that could emerge in the future.

The voltage stability analysis uses a P-V study methodology where power is transferred between a defined source and sink. At different transfer levels, contingencies are introduced, and the resulting bus voltages calculated. The voltage stability limit is reached when the solution fails to converge due to voltage collapse or when a bus falls outside of planning criteria. MISO uses transmission owner (TO) local planning criteria (LPC) to define stability limits should TOs decide to institute criteria more restrictive compared to MISO defaults found in BPM-020. In absence of TO LPC, MISO uses a default margin value of 10%, with the margin being defined from the point of voltage collapse (i.e., nose point) of the PV curve. MISO also has criteria for each bulk electric system (BES) bus to maintain voltage at or above 90% of nominal voltage under contingency conditions. Figure C-4 shows an example PV curve with the 90% voltage decline criteria limit; the limit corresponding to 10% margin; and the nose point.

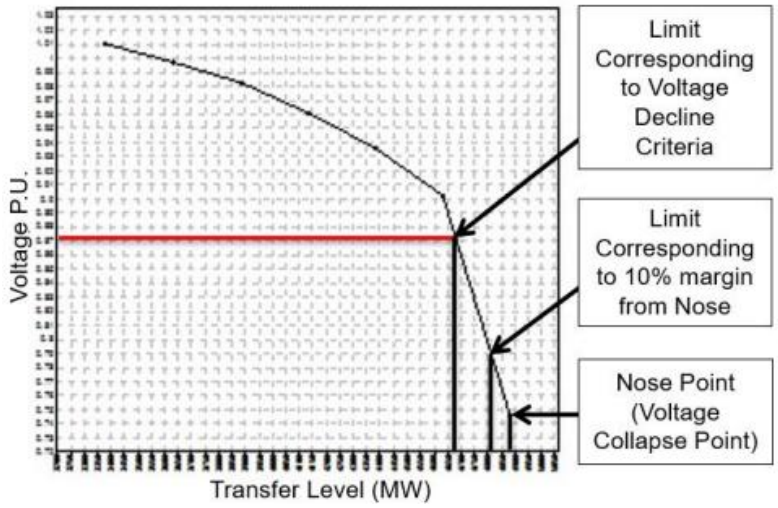


Figure C-4. Illustration of power-voltage (PV) curve with associated limits

To provide an idea of the scale of MISO's current voltage stability analysis, the MTEP23 cycle selected six transfer scenarios across the MISO region, as shown in Figure C-5. The assessment follows established methodologies pursuant to requirements in NERC Standards FAC-010 and FAC-014. FAC-010 requires that System Operating Limits (SOL) used in BES reliability planning are based on an established methodology or methodologies.[26] Voltage stability is specifically called out in Requirement 2 of this standard. FAC-014 serves the purpose of establishing how SOLs, including voltage stability limits, are communicated among the NERC registered entities.[27]

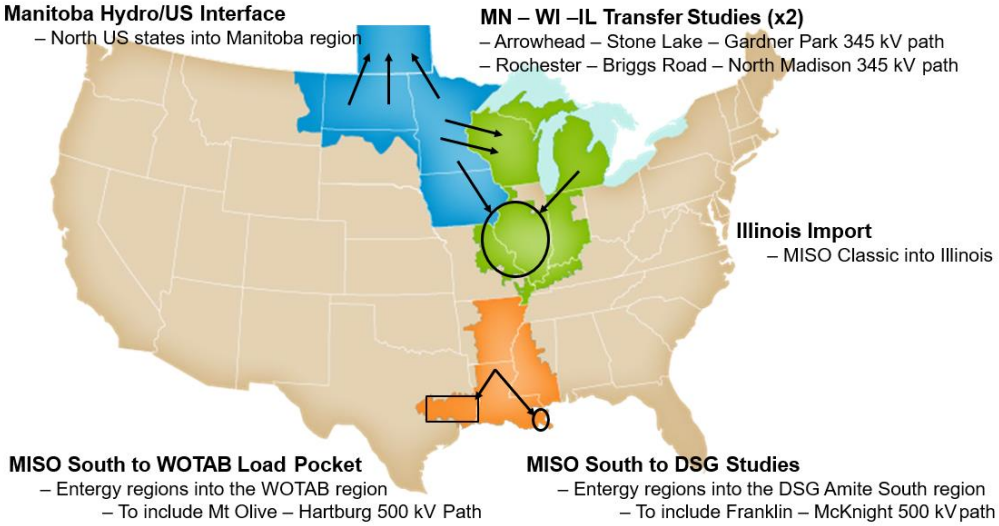


Figure C-5. Geographical representation of the six transfer scenarios selected for MTEP23

[26] NERC, Standard FAC-010-3 – System Operating Limits Methodology for the Planning Horizon.

[27] NERC, Standard FAC-014-3 – Establish Communication System Operating Limits, January 2009.

C.2.3 Operations

MISO real-time operations currently run around 30 contingencies, which primarily monitor two interfaces for stability issues. In what will amount to a large expansion of the current monitoring, recent changes to NERC's FAC-011-4 standard caused MISO to start developing a real-time, footprint wide transient stability analysis. Contingencies will be selected through a screening methodology. The project is planned for completion in December 2023, ahead of the April 2024 date on which the revised FAC-011-4 becomes active.

Voltage Stability Insight #1:

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

C.2.4 Markets

Currently, MISO does not offer market products directly related to voltage stability.

C.3 Attributes Voltage Stability Analysis

The voltage stability portion of the 2023 attributes analysis work focused on characterizing screening results using both the SCR and dynamic impedance approaches. Screening approaches, including those contemplated in this analysis, are often used to identify areas and conditions that require deeper analysis.

C.3.1 Limitations of Screening Tools

SCR is known to have limitations in areas of high inverter-based resource (IBR) penetration. This metric is most appropriate when considering an IBR connected to a strong grid without the interactions from other nearby IBR. Adaptations of SCR approaches intended to overcome known shortcomings are described below. However, modern inverter control topologies are beginning to decouple the IBR's fault contribution from system strength contributions, concepts that are tightly coupled in grids predominantly driven by synchronous machines.

While the dynamic impedance method is relatively new, and MISO is working with industry partners – Telos Energy and Hickory Ledge – to advance industry understanding of its use and usefulness, patterns around certain limitations are emerging. One insight thus far is that characterizing grid-following (GFL) IBR using the approach presents challenges, especially for large disturbances, such as faults resulting in severe voltage depressions. The method could potentially benefit from severity-sensitivity adjustments to the dynamic impedance for GFL. For grid-forming (GFM) IBR the large-signal and small-signal screening outcomes appear to be accurate, but MISO is still investigating the efficacy for this use based on other industry research evaluating similar approaches. [28] [29] [30]

C.3.2 Short-Circuit Ratio

SCR has traditionally represented the "voltage stiffness" or system strength of a grid.[31] It is used as a screening method to understand potential reliability implications, especially as IBR deployments and synchronous machine

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[28] 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.

[29] Sun J. "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.

[30] Shah, Shahil, 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".

[31] NERC, *Short-Circuit Modeling and System Strength*, February 2018.

resource retirements lower the available system short-circuit current. This reduction in available short-circuit current can drive weak grid conditions that may cause plant and inverter control instability, for instance plants oscillating against one another. Other potential challenges of low system strength include[32]:

- Delayed voltage recovery
- Wide area undamped voltage and power oscillations
- Instability of plant voltage control systems
- Deeper voltage dips and higher overvoltages
- Larger voltage step change for switched compensation equipment
- Generator fault ride-through degradation
- Protection misoperation

SCR is calculated at each bus location and is the ratio of the available three-phase fault current (in MVA) over the active power rating of the resources at a given bus. This is described by equation 1 below.

$$SCR = \frac{S_{SCMVA}}{P_{RMW}} \qquad (1)$$

Variations of SCR have been developed across the industry to counteract known limitations of SCR as a system strength screening metric. The SCR method assumes a system with predominantly synchronous generation[31], therefore its use on systems with high IBR penetration may result in a conservative estimation because it does not account for IBR interaction effects[33] [34] [35]. Weighted short-circuit ratio (WSCR), defined in footnote 33, determines the system strength across an area rather than a single bus and accounts for the short-circuit contribution of each bus and active power rating of each generator in the same equation. The main limitation of this method is that it assumes all interacting IBRs are connected at the same bus. The system strength represented in WSCR can provide a lower bound to the estimation from the SCR metric while still providing a limited measure of an IBR-dominant system. Other methods (ESCR, CSCR, SCRIF, etc.) that focus only on analyzing the line impedance generally share the same limitation.[31] [35]

While variations like WSCR can address certain shortcomings of SCR, such as IBR interactions, they cannot capture the stability benefits of new IBR technologies such as grid-forming controls. This indicates a need to evaluate other approaches for system strength screening, such as the dynamic impedance method described further below.

Tools

MISO's methodology uses a Python script to automate SCR calculation across all buses in the MISO footprint. The script interfaces with the PSS/E powerflow software through API commands to simulate three phase faults at different buses in the model, then calculates the resulting SCR at that bus. The PSS/E fault calculation method was automatic sequencing (ASCC) and used the subtransient generator reactance values.

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[32] AEMO, *System Strength*, March 2020.

[33] Y. Zhang *et al.*, "Evaluating system strength for large-scale wind plant integration," IEEE PES General Meeting, National Harbor, MD, pp. 1-5, July 2014.

[34] J. Schmall *et al.*, "Voltage stability of large-scale wind plants integrated in weak networks: An ERCOT case study," IEEE PES General Meeting, Denver, CO, pp. 1-5, July 2015.

[35] C. Henderson *et al.*, "Grid Strength Impedance Metric: An Alternative to SCR for Evaluating System Strength in Converter Dominated Systems," *IEEE Transactions on Power Delivery*. Institute of Electrical and Electronics Engineers (IEEE), pp. 1-10, January 2023

In addition, ArcGIS software was used to create the SCR map visualizations using MISO bus latitude and longitude data.

Models

MISO Transmission Expansion Plan 2023 (MTEP23) Appendix A powerflow models were used for the SCR analysis.[36] There are separate models for different future years (2025, 2028, and 2033) and dispatch cases (summer, spring light load, etc.). The MTEP models include resource additions based only on projects with signed GIAs and retirements based only on plants with finalized retirement studies.

To improve SCR calculation accuracy, machine subtransient reactance values for synchronous generators were pulled from the MTEP23 five-year-out dynamics data file and added into the sequence data of the base powerflow model. Subtransient reactance class averages were used for synchronous machines that did not have individual dynamics data available. For all non-synchronous machines a value of 0.91 p.u. subtransient reactance was assumed.

Results

MISO's refreshed SCR analysis confirms the RIIA study results showing localized pockets of declining system strength. However, the picture is nuanced as increasing SCR is projected in some areas as well. Figure C-6 through Figure C-8 below show the magnitudes of SCR for the MTEP23 2025, 2028, and 2033 summer dispatch cases. Potential areas of low system strength appear to be Michigan, SW Minnesota, and Louisiana.

SCR magnitude results were split into three categories:

- "Low" SCR was defined as an SCR value less than 3
- "Medium" SCR was defined as an SCR value less than 6
- "High" SCR was defined as an SCR value greater than or equal to 6

These categories are meant to be illustrative and are not meant to exactly indicate the system strength at which stability or control issues will arise. For example, industry sources have suggested Type 3 WTG have a potential for control problems with SCR < 2.5 and cannot maintain control for SCR < 1.5.[37] MISO understands that various manufacturers' equipment is designed to operate at different minimum SCR levels, sometimes stated in their technical materials. Therefore, the SCR evaluation is reserved for initial screening with detailed analysis determining stability risks and mitigations.

[36] MISO, *Draft MTEP 2023*, 2023.

[37] Electranix, "Why GFM?," presentation to UNIFI consortium, September 11, 2023.

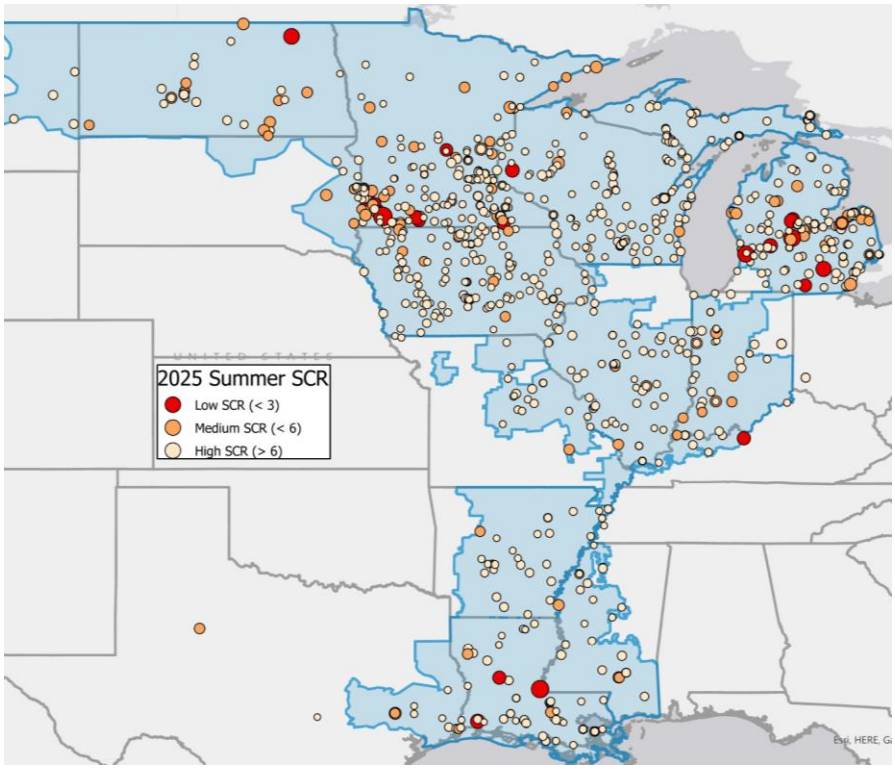

Figure C-6. SCR magnitudes for MTEP23 2025 summer dispatch model

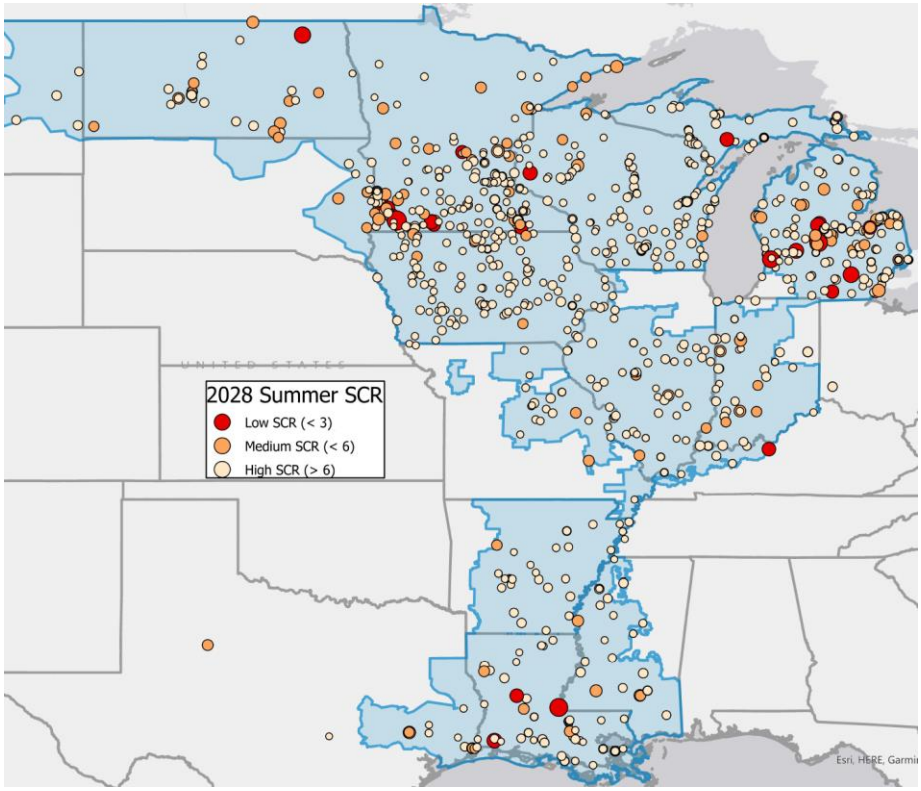

Figure C-7. SCR magnitudes for MTEP23 2028 summer dispatch model

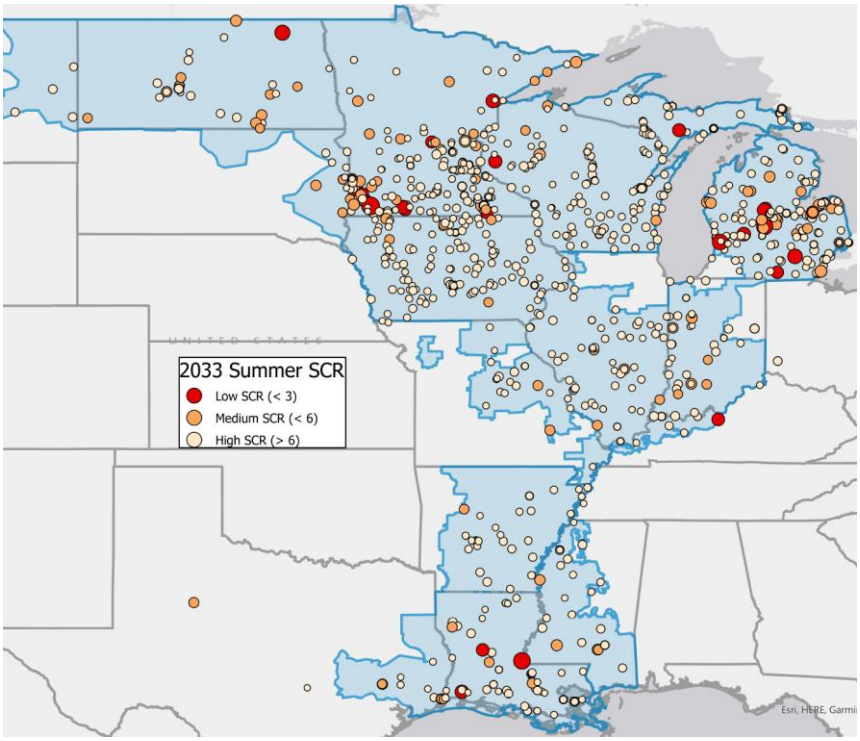

Figure C-8. SCR magnitudes for MTEP23 2033 summer dispatch model

SCR magnitudes are different based on the dispatch pattern selected for each model year, indicating that 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. Figure C-9 shows an example of the SCR values for buses in the 2025 model under the spring light load (SLL) dispatch assumption. In the SLL case, SCR is lower across much of Iowa, Wisconsin, and MISO South compared to the summer dispatch case.

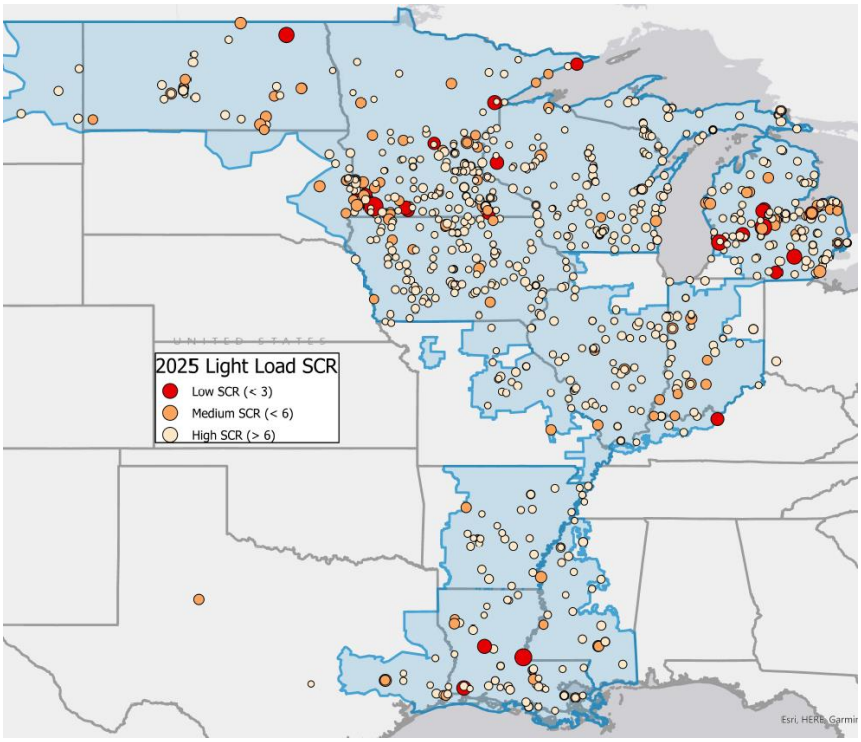

Figure C-9. SCR magnitudes for MTEP23 2025 spring light load dispatch model

The nature of the resource transition and transmission build-out will drive future system strength, affecting aspects of system stability. For example, between the 2025 and 2033 MTEP models, transmission build-out from LRTP Tranche 1 works to increase system strength while fleet changes decrease it.

Figure C-10 isolates the impacts of resource additions and retirements on SCR between 2025 and 2033. It compares the SCR of the 2025 model with the SCR of an altered 2033 model with MISO's LRTP Tranche 1 projects removed. The removal of these major transmission projects aims to isolate the impacts of resource changes, but it is acknowledged that the 2033 case still includes other transmission additions not associated with Tranche 1. There are some localized areas with synchronous generator retirements and IBR additions where SCR decreases, but there are also many areas where SCR increases over time.

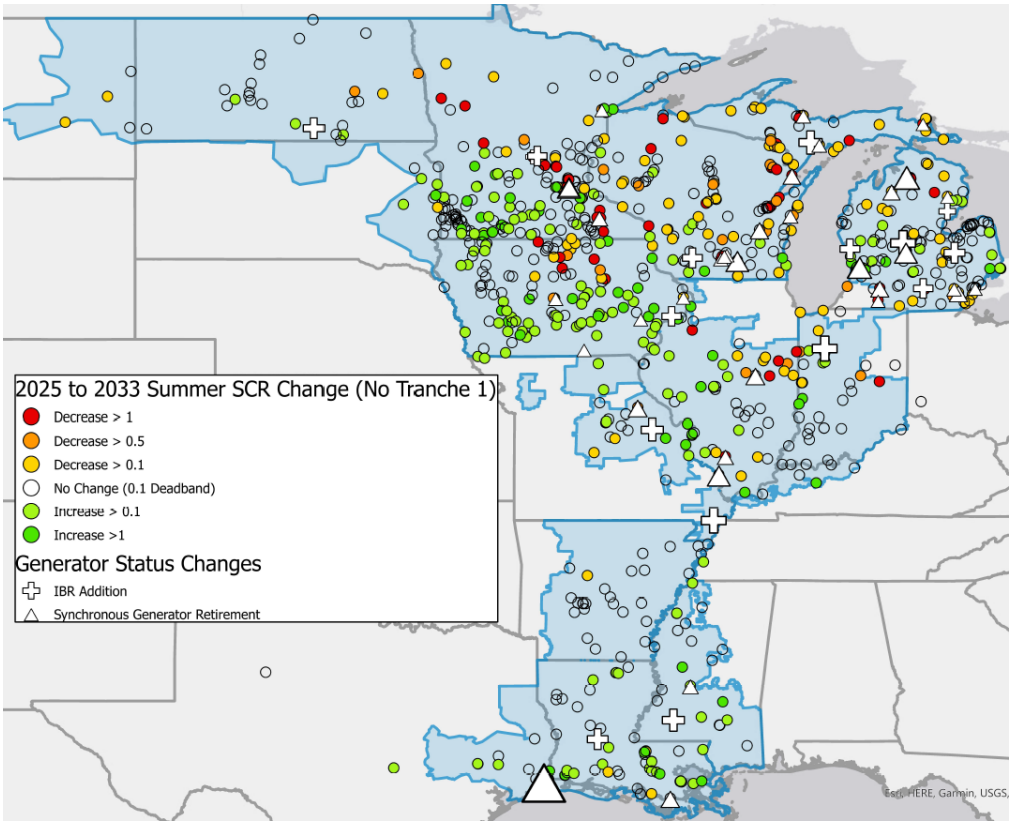

Figure C-10. Impact of resource additions and retirements on SCR, shows the change in SCR from the MTEP23 2025 summer model to the MTEP23 2033 summer model without LRTP Tranche 1 projects

Figure C-11, alternatively, isolates the impact of LRTP Tranche 1 by comparing the difference in SCR in the 2033 model before and after Tranche 1 projects are added. SCR increases when the Tranche 1 projects are added at nearly every bus across the MISO North and Central regions. There is no change in SCR due to Tranche 1 in MISO South as expected, because the transmission projects are limited to the North and Central region only.

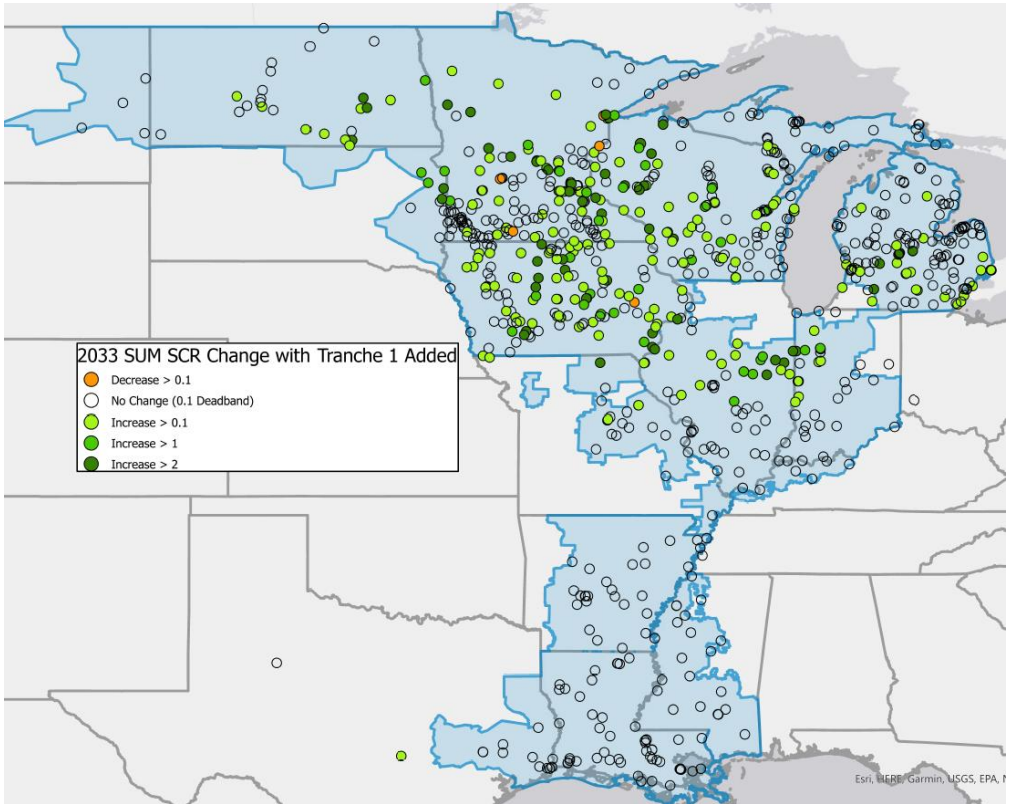

Figure C-11. Impact of LRTP Tranche 1 projects on SCR, shows the change in SCR for the MTEP23 2033 summer model with and without LRTP Tranche 1 projects

The SCR changes in Figure C-10 and Figure C-11 are summarized in Figure C-12 below. Across the entire MISO footprint, Tranche 1 increased average SCR by 0.7 (from 37.1 to 37.8) while resource changes and other transmission changes (e.g., projects generated by Local Planning Criteria) between 2025 and 2033 resulted in average SCR remaining the same (in both cases 37.1).

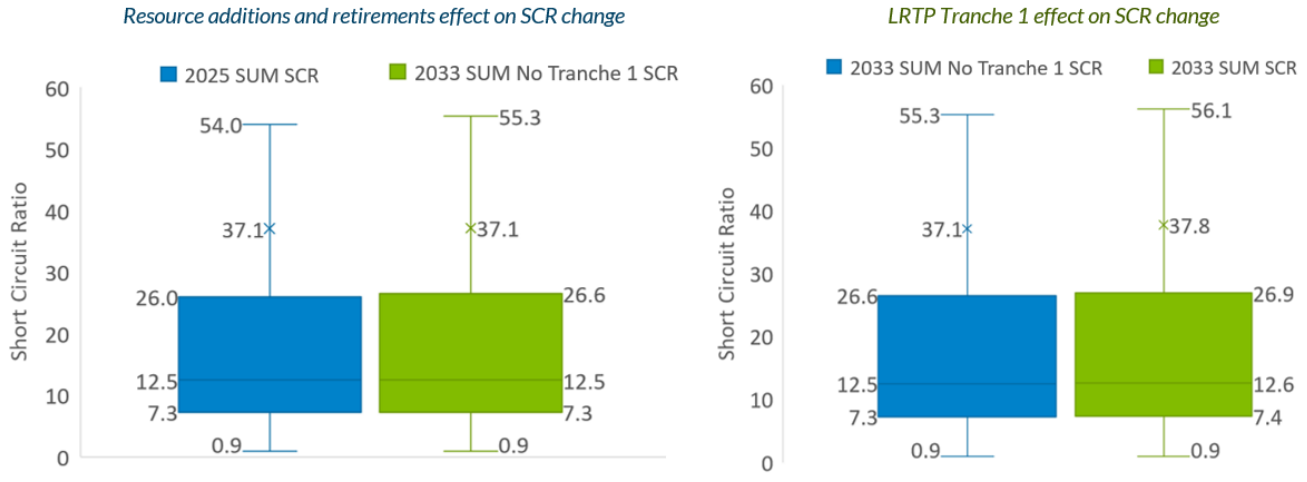

Figure C-12. Comparison of how resource change impacts SCR to how LRTP Tranche 1 projects impact SCR

C.3.3 Dynamic Impedance Method

The dynamic impedance approach development was led by Telos Energy and Hickory Ledge as part of a MISO engagement to understand potential IBR stability impacts. MISO's RIIA study did not incorporate grid-forming controls as a potential mitigation to voltage stability challenges due to the lack of industry available models and demonstration projects, which drove a need to better understand the potential of control solutions.

A paper describing the dynamic impedance method was presented at a recent industry conference in *22nd Wind and Solar Integration Workshop*[38]. MISO suggests readers refer to this paper for details on the method's purpose, formulation, and validation. This section will provide a brief overview of the method before discussing scaling the analysis to the full MISO system, which is not covered in the conference paper.

Voltage Stability Insight #2:

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

The dynamic impedance method consists of two main processes, a resource characterization and a screening analysis as shown in Figure C-13. First, the resource characterization is performed using detailed electromagnetic transient (EMT) analysis to determine the modeled IBR's dynamic responses to voltage and frequency disturbances. A "dynamic impedance" value is extracted from certain perturbation frequencies in the direct-quadrature-zero (dq0) domain, sometimes also referred to as the rotor reference frame. Then, this dynamic impedance value is fed into a screening analysis. The screening is a traditional voltage stability transfer analysis using a tool called TARA to approximate the dynamic voltage stability limits. Applying a steady-state type of analysis to approximate dynamic limits reduces complexity and computational burden.

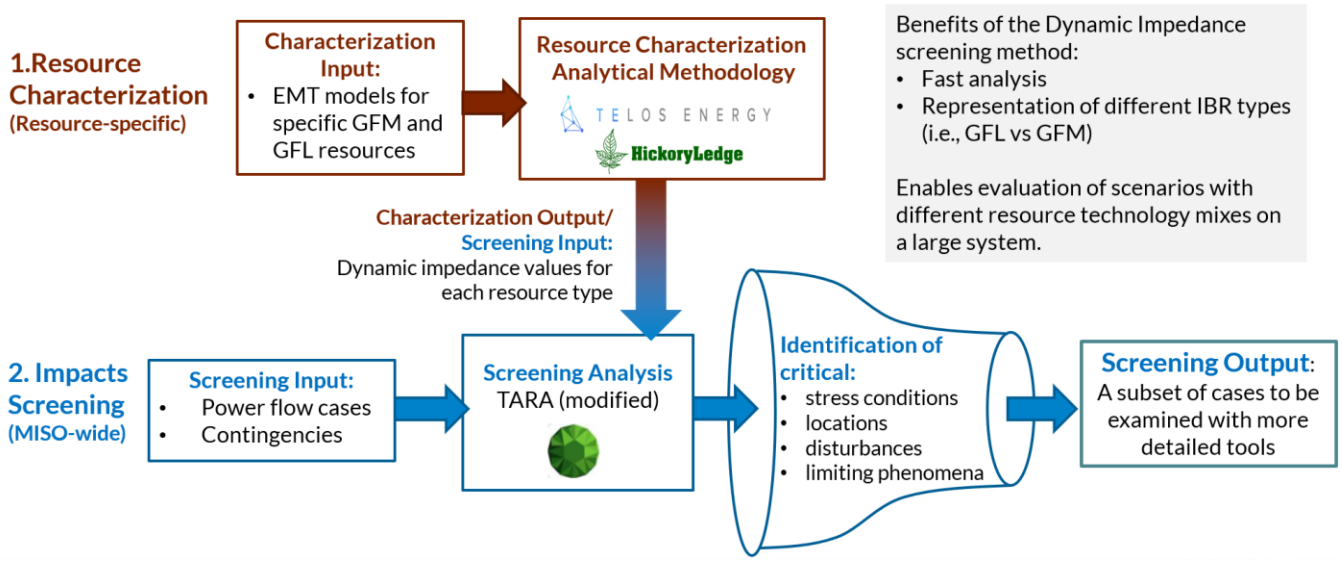

Figure C-13. Process diagram of the Dynamic Impedance screening method

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

Tools

A range of tools currently available at MISO are required to carry out the dynamic impedance method. Table C-1 summarizes the tools used in the dynamic impedance method.

Tool	Type	Dynamic impedance application
PSCAD	EMT Simulation	Extracting dynamic impedance from resource models.
PSS/E	Positive sequence domain power flow	Solving a power flow case for use in TARA.
TARA	Linear power flow transfer analysis	Performing PV curve analysis for screening.

Table C-1. Summary of tools used for dynamic impedance approach

First, an EMT simulation is required using PSCAD software to characterize a resource and extract the crucial dynamic impedance characteristics. Next, an iterative process is automated in PSS/E to generate a solved case while modifying the location of voltage regulation to effectively be internal to the resource rather than at the resource terminals. The reactive power limits (Q) still apply at the generator terminals. The process is iterative by nature as the internal voltage must be calculated based on terminal voltage and known impedance rather than directly controlled within a tolerance band. Figure C-14 illustrates the difference between conventional and dynamic impedance approach treatment of reactive power limits and voltage regulation.

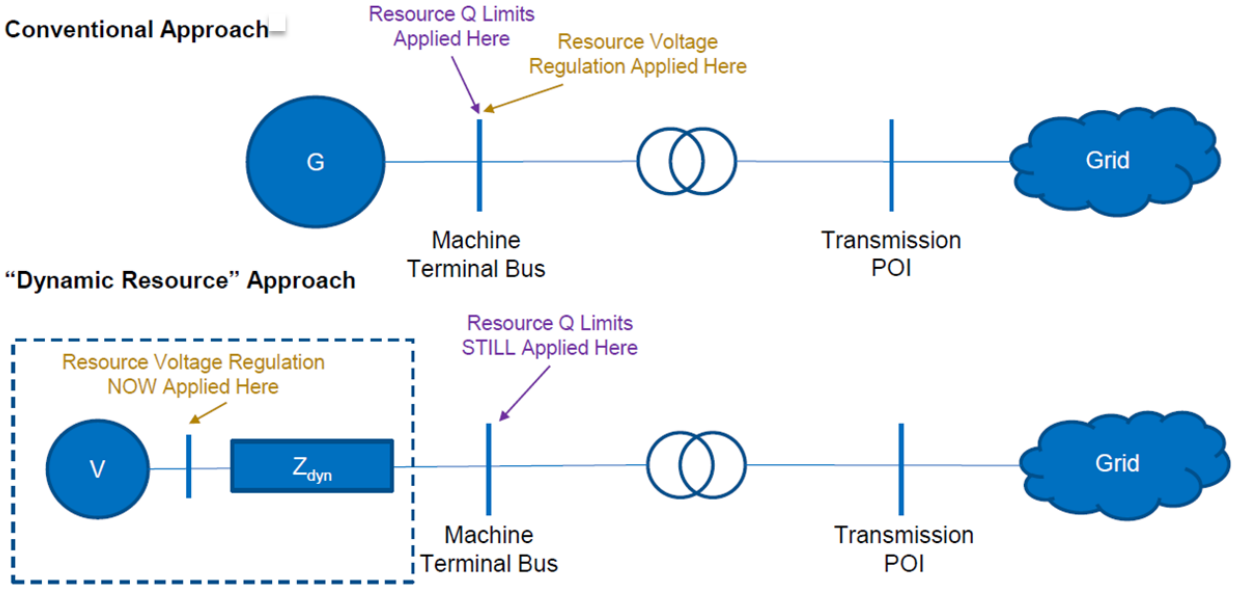

Figure C-14. Illustration of voltage regulation and active power limit application in conventional and dynamic impedance approaches (source: Telos Energy)

Finally, a tool called TARA is used to generate a PV curve used for estimating a dynamic voltage stability limit.

Models

The model used for validation was a six-bus reduced model that was roughly representing a portion of the MISO system that includes areas in South Dakota, Iowa, Minnesota, and Illinois. This area was selected based on existing

transfers resulting from wind generation to the west and load to the east. More information on the validation process and results are found in the technical paper referenced above.[39]

The scaled analysis started with the MTEP23_2033_SUM_AA model for the base case and used a modified version of this model – treating some of the synchronous machines as IBR – to generate a high penetration IBR case. The Illinois interface transfer was used as a starting point but was modified to stress a subset of this system sourced from ALTW and MEC and sunk in AMIL. The transfer was scaled up for this limited portion of the system to accentuate the results for demonstration purposes, making this an unrealistic transfer from the perspective of typical planning processes. Further, an extraordinary contingency (i.e., beyond NERC TPL Standards) was used to accentuate the difference in static and dynamic limits. Two 345 kV lines were taken out simultaneously to stress the system, which is labeled as "N-1" for this demonstration. MISO emphasizes the demonstration nature of this case. Figure C-15 shows a simplified system diagram with the green circle denoting the export area and the red circle denoting the import area. The two lines with "x" marks include the two 345 kV lines taken out for the contingency for demonstration purposes.

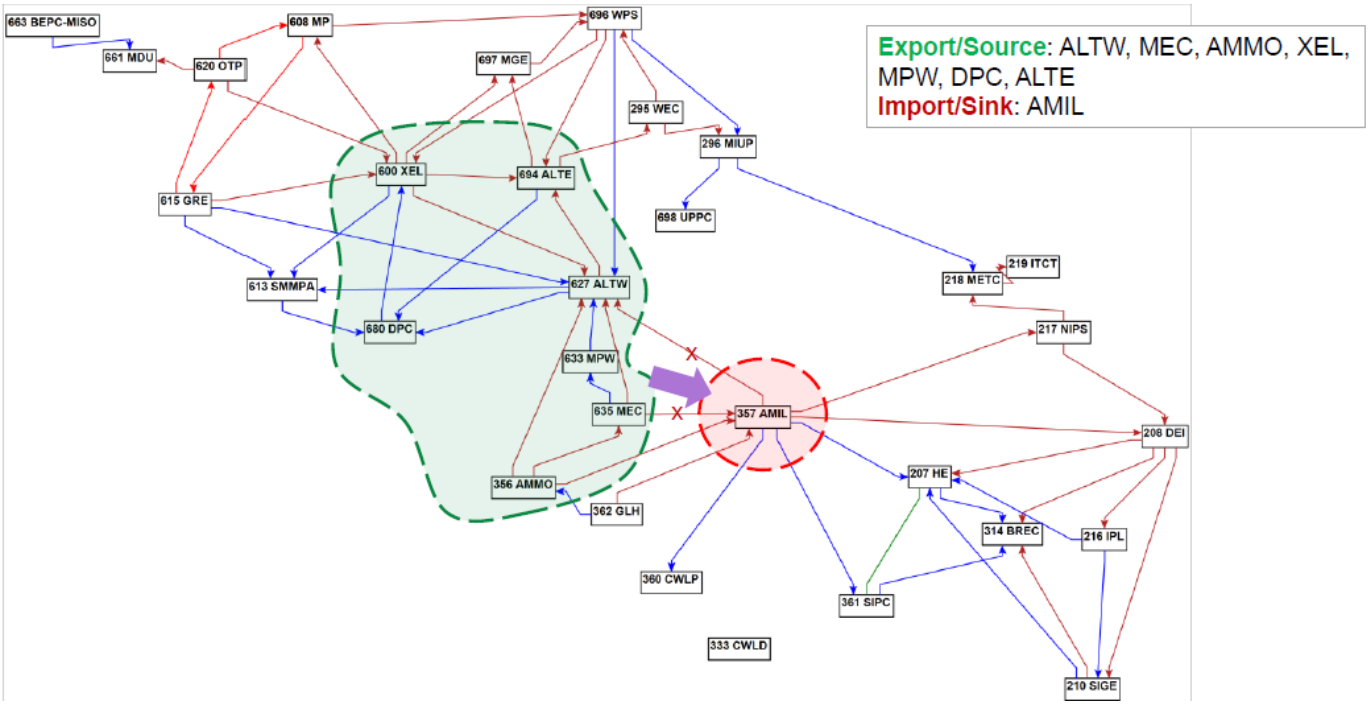

Figure C-15. Illustration of modified transfer used for demonstrating dynamic impedance approach on scaled MISO system model

The base case and high IBR case resource mix assumptions are shown in Table C-2. As previously noted, the base case assumptions are directly from the MTEP model and the high IBR penetration case treats some of the IBR in three of the areas as synchronous machines (SM) to stress the case for demonstration purposes.

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

Area	Base Case		High IBR Penetration	
	MVA SM	MVA IBR	MVA SM	MVA IBR
357 AMIL	12780	4840	8820	8810
627 ALTW	6670	5949	6280	6330
635 MEC	7230	8730	7230	8730

Table C-2. Resource assumptions for scaled dynamic impedance demonstration

Within the base case and high IBR penetration case, the proportion of IBR assumed to be GFM versus GFL was varied using 90%/10% weightings for each technology, generating additional scenarios. Figure C-16 shows the proportions of synchronous machines (SM), GFL, and GFM used in the scaled analysis.

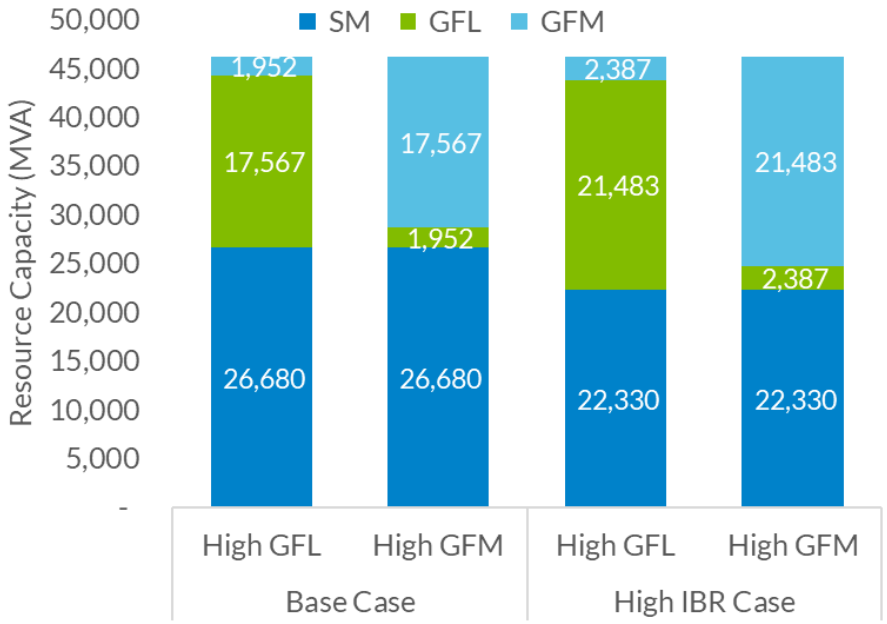

Figure C-16. Resource breakdown for each case and scenario

Dynamic impedances were applied to all large resources, amounting to approximately 1100 generators, using impedance values derived from resource characterization. For computational efficiency, small generators (e.g., less than 50 MVA) were excluded from dynamic impedance assumptions. The first step in modifying impedance of large generators was to map existing fuel types in the model to the three types of resources for which dynamic impedance is assigned: inverter-based resources and synchronous machines. Figure C-17 shows the mapping used in this analysis.

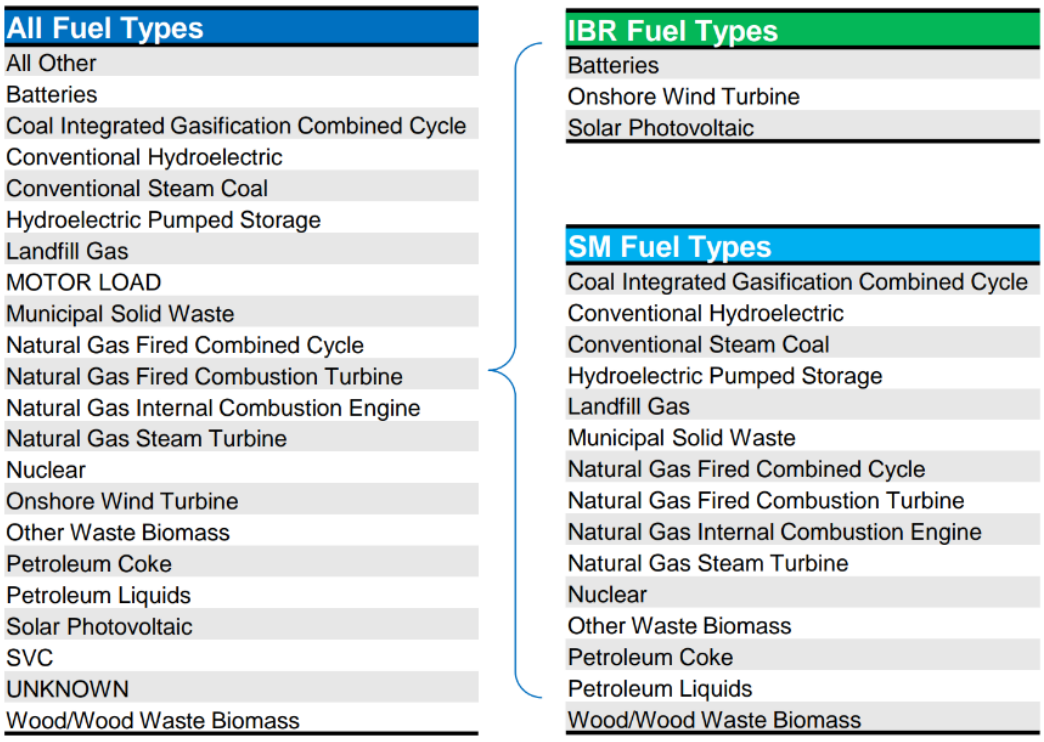

Figure C-17. Mapping of modeled fuel types to IBR and synchronous machines (SM)

The dynamic impedance values found from resource characterization were applied as assumptions in the power flow model. The demonstration used a prototypical value for each technology type, listed in Table C-3. Future work could increase granularity by using separate dynamic impedance assumptions for different IBR models and synchronous machine fuel types.

Technology type	Dynamic impedance assumption (p.u.)
Grid following IBR	1.2
Grid Forming IBR	0.1
Synchronous Machine	0.5

Table C-3. Dynamic impedance assumptions by technology type

Resource Characterization Results

The dynamic impedance method characterized six different inverters using detailed EMT models, as show in Figure C-18. The chart has admittance on the y-axis and frequency of disturbance on the x-axis (dq frame, or rotor reference frame). A high dynamic admittance translates to more effective voltage regulation over that specific frequency; this could be interpreted simply as higher system strength support. The different lines in the chart depict characterizations of commercially available makes and models of GFL and GFM technologies, representing several

major manufactures in the U.S. market. The analytical resource characterization extracts impedance information around the 10 Hz range, reflecting the time period of interest following a disturbance.[40]

MISO suspects a few causes to be driving differences in responses for a given technology type (e.g., GFM). Different control strategies could potentially drive differences. For instance, GFM technology can be implemented using virtual oscillator controls, droop-based controls, or virtual synchronous machine controls.[41] The parameterization, or settings for functional control, can also impact the IBR response and thus characterization. This means that each IBR must be characterized with the planned parameterization unless or until a standards-based approach steps in that would make generic models and parameterization more useful.

Voltage Stability Insight #3:

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.

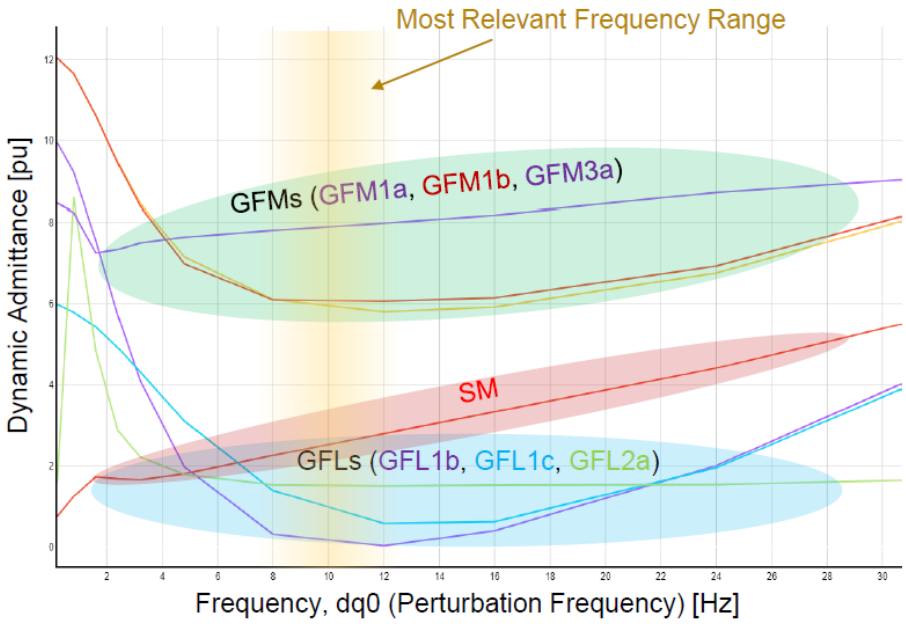

Figure C-18. EMT analysis characterizing three different commercially available grid forming (GFM) and grid following (GFL) inverter models (source: Telos Energy)

The resource characterization indicates that GFM controls are superior to GFL controls in terms of supporting stability. However, the comparison with synchronous machines is more nuanced, as the energy limitations of IBR must also be considered. Machine construction typically facilitates high current, short term overloads, whereas the energy limitations of IBR may not allow for such overloads.

[40] Selecting this range, and how to view impedance scans more generally, is an area of active research, with organizations like ESIG actively facilitating Task Force discussions that are considering a slightly different range; in to 4 Hz to 40 Hz range.

[41] NREL, *Stabilizing the Power System in 2035 and Beyond: Evolving from Grid-Following to Grid-Forming Distributed Inverter Controllers (Final Technical Report).* August 2021

It is important to note that the characterization results represent a specific range of disturbances. Further work is needed to understand the limitations associated with control non-linearities, as might be the case for a control under larger disturbances.

Transfer Capacity Results

Incorporating the resource characterization into the dynamic impedance process, Figure C-19 represents the output of the screening tool, which are PV curves that come out of the TARA tool. The vertical axis represents voltage and the horizontal axis is the MW transferred. The blue curve at the top is the same in both charts, representing a standard PV curve for a contingency without any modifications from the new method. At a high level, these curves represent the output of a voltage stability transfer analysis, showing declining voltages as transfer levels increase. The voltage magnitude is found at each transfer point, and the highest transfer point shows the voltage stability transfer limit. Voltage collapse is expected beyond this point.

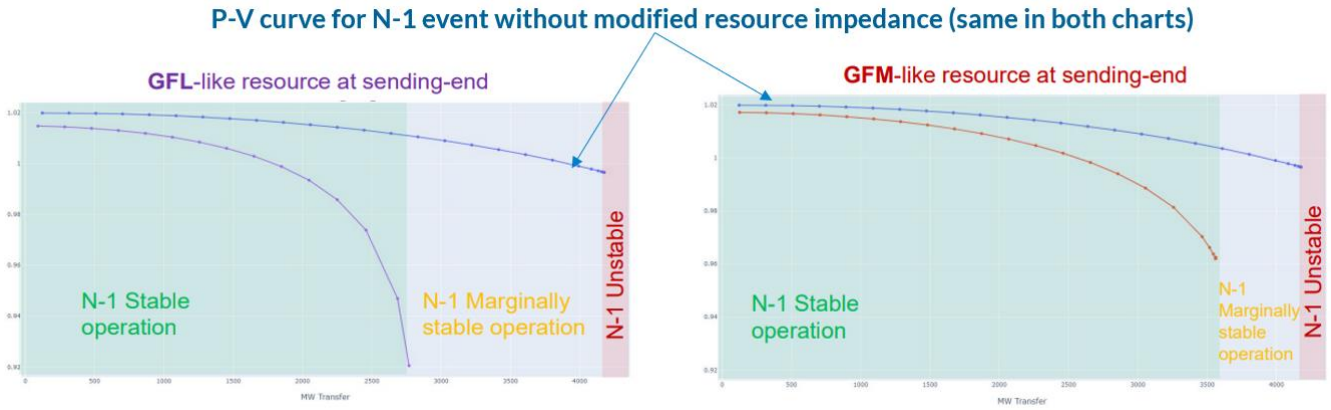

Figure C-19. Illustration of dynamic impedance screening results for GFL and GFM resources at the sending-end

The dynamic impedance screening analysis is a way to approximate dynamic stability limits using a tool and method (i.e., TARA's PV curve analysis) that is typically used to evaluate static transfer limits, under normal and contingency conditions. The lower PV curve on each chart in Figure C-19 represents analysis that incorporates the dynamic impedance values in the input assumptions. The left-hand side assumes GFL resources at the sending end, whereas the right-hand side assumes GFM. GFM resources show a greater contribution to dynamic stability, increasing the limit beyond what GFL supports. Dynamic stability limits are lower than the static limit in this test case, though voltage or thermal limits may often be the constraints in today's system analysis. The screening limit, marked by the yellow "marginally stable operation" region, would be used as a threshold for considering more detailed analysis methods (e.g., positive sequence domain simulations) to find the actual dynamic stability limit.

Applying this screening approach to the scaled MISO system described in the Models section, PV curves were generated for the different base case and high IBR case scenarios (i.e., high GFL versus high GFM). Figure C-20 shows the PV curves generated by TARA for each case, with the bookends of high GFL versus high GFM scenarios in the high IBR case. When considering dynamic voltage stability limits, the high GFL scenario in high IBR case resulted in a transfer limit of 8,976 MW whereas the high GFM scenario in high IBR case resulted in a limit of 9,833 MW. This result implies that GFM controls could improve dynamic stability limits by around 10% when compared to GFL controls in a high IBR case.

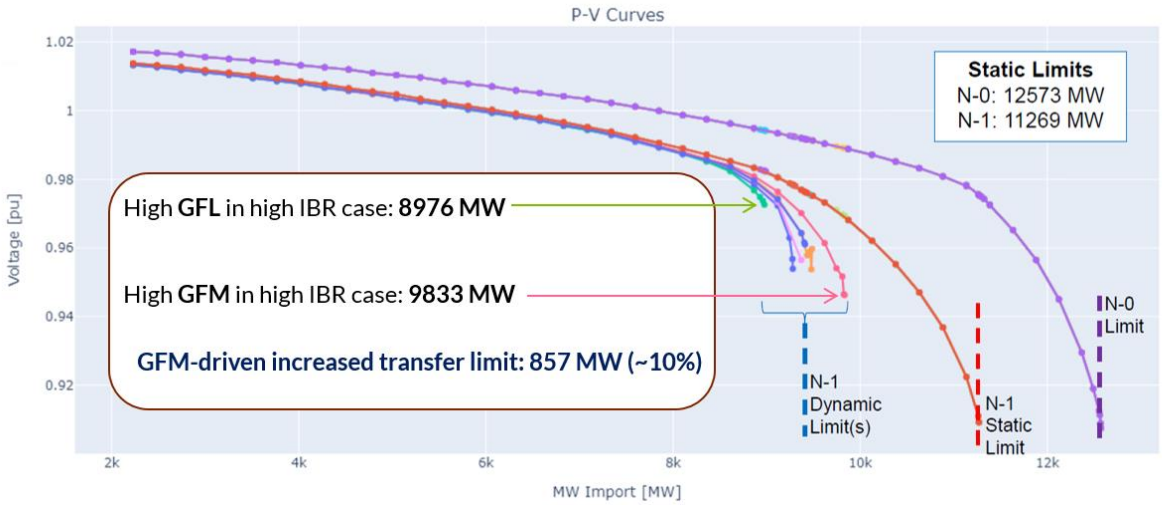

Figure C-20. Dynamic impedance screening results on the scaled-up MISO system

Another notable result from the analysis is how high levels of GFL controls in a high IBR scenario drive lower voltage stability transfer limits when compared to the base case, suggesting that high proliferation of GFL controls without GFM support could lead to new voltage stability constraints. The high GFL in a high IBR scenario has transfer levels that are 304 MW less than the base case. Consistent with the GFM stability gains discussed above, high GFM in the high IBR case leads to higher stability limits, by 347 MW, when compared to the base case with high GFM scenario. Figure C-21 shows select comparisons between the cases and scenarios, indicating transfer capability increases or decreases.

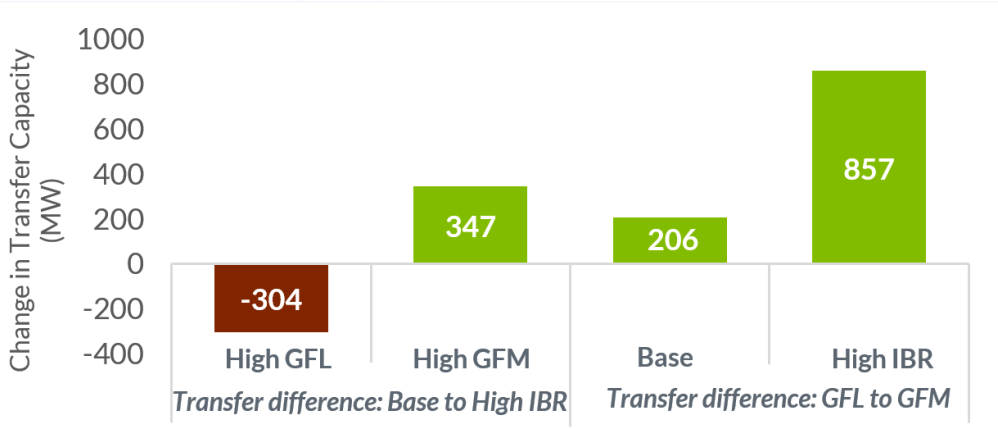

Figure C-21. Comparison of potential transfer capacity for select cases and scenarios

C.4 Conclusion

This technical appendix section described approaches, tools, and assumptions used in the voltage stability attributes analysis that informed insights and roadmap development. Please refer to the *Attributes Roadmap* for the proposed solution hypothesis based on this analysis.

D. Attribute Support from MISO's Market Structures

The following table summarizes the list of MISO's Markets, as of November 2023. The table summarizes how each Market structure supports the relevant attributes discussed in MISO's *Attributes Roadmap*. The voltage stability attribute risk-factor is excluded from Table D-1 given that MISO currently has no market products related to voltage stability.

Market	Attribute Risk-Factor	Market Product	Geographic Granularity	Requirement	Offer Cap	Max. Scarcity Price	Why does this market exist? What is the business case?
Resource Adequacy	**Availability/ Fuel Assurance/ Energy Assurance**	**Capacity Planning Resource Auction**	Local Resource Zone (LRZ)	MISO calculated LRZ needs and import/ export limits	Cost of New Entry (CONE)	Cost of New Entry (CONE)	Address resource adequacy needs in MISO's footprint
FTR	**N/A**	**Financial Transmissio n Rights**	Point-to-Point	n/a			FTRs are financial instruments used to hedge the risk of congestion cost in the Day-ahead Market.
		Auction Revenue Rights (ARRs)	Point-to-Point	Allocated based on firm historical usage	Allocation process; no market offer	n/a	ARRs are entitlements to a share of the revenues generated in the annual FTR Auction to address transmission investments.
Day-Ahead Energy and Operating Reserves Market	**Ramp Up Capability/ Rapid Start-Up**	**Energy**	Nodal	Demand Bids	$1,000 (soft cap), $2,000 (hard cap)	Value of Lost Load (VOLL) ($3,500)	The Energy market uses transmission and generation assets more efficiently and reduces the need of additional assets.
		Regulating Reserve	System-wide	300-500MW, depending on hour of day	$500	Regulation Demand Curve, up to VOLL	Address small deviations in frequency and tie-line flows, meeting NERC standards.
		Spinning Contingency Reserve	Reserve Zone with RPE	901 - 1201 MW, depending on hour of day	$100	ORDC* plus Spin Demand Curve, up to VOLL	Address larger deviations resulting from system contingencies, meeting NERC standards.
		Supplement al Contingency Reserve	Reserve Zone with RPE	1,109 MW	$100	ORDC, up to VOLL	Address larger deviations resulting from system contingencies, meeting NERC standards.
		Short Term Reserves	System-wide, Sub-Regional, Local	~3,600 MW (System-wide)	None for on-line; $100 for off-line	$100-200	Efficiently ensure capacity to manage imbalance and reserve replacement
	Ramp Up Capability	**Ramp Capability Product (Up and Down)**	System-wide	Based on estimated real-time needs	No offer	$5	Manage resource flexibility to address forecast uncertainties.

Table D-1: Current MISO's Markets and their support for attributes

Market	Attribute Risk-Factor	Market Product	Geographic Granularity	Requirement	Offer Cap	Max. Scarcity Price	Why does this market exist? What is the business case?
Real-Time Energy and Operating Reserves Market	**Ramp Up Capability/ Rapid Start-Up**	**Energy**	Nodal	Short Term Load Forecast	$1,000 (soft cap), $2,000 (hard cap)	Value of Lost Load ($3,500)	The Energy market uses transmission and generation assets more efficiently and reduces the need of additional assets.
		Regulating Reserve	System-wide	300-500MW, depending on hour of day	$500	Regulation Demand Curve, up to VOLL	Address small deviations in frequency and tie-line flows, meeting NERC standards.
		Spinning Contingency Reserve	Reserve Zone with RPE	901 - 1201 MW, depending on hour of day	$100	ORDC plus Spin Demand Curve, up to VOLL	Address larger deviations resulting from system contingencies, meeting NERC standards.
		Supplemental Contingency Reserve	Reserve Zone with RPE	1,109 MW	$100	ORDC, up to VOLL	Address larger deviations resulting from system contingencies, meeting NERC standards.
		Short Term Reserves	System-wide, Sub-Regional, Local	~3,600 MW (System-wide)	None for on-line; $100 for off-line	$100-200	Efficiently ensure capacity to manage imbalance and reserve replacement
	Ramp Up Capability	**Ramp Capability Product (Up and Down)**	System-wide	Based on short-term load forecast and uncertainty	No offer	$5	Manage resource flexibility to address forecast uncertainties.

Table D-1: Current MISO's Markets and their support for attributes (continued)

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-7

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

Filed September 5, 2025

Exhibit 87

MISO's Response to the Reliability Imperative

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

RECENT KEY ACCOMPLISHMENTS

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

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

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

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

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

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

MISO PRIORITIES GOING FORWARD

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

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

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

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

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

CALL TO ACTION: WE MUST WORK TOGETHER AND MOVE FASTER

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

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

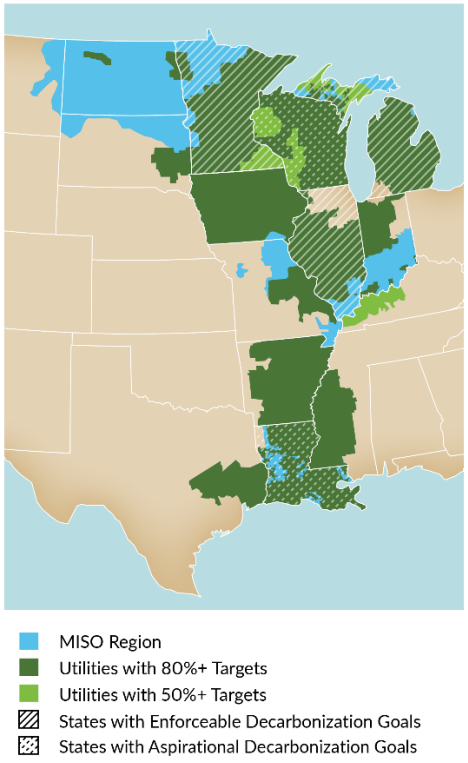
CONTINUED STAKEHOLDER INPUT IS CRUCIAL

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

Challenges Driving the Reliability Imperative

COMPLEX POLICY LANDSCAPE

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



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

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

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

TIGHTENING SUPPLY

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

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

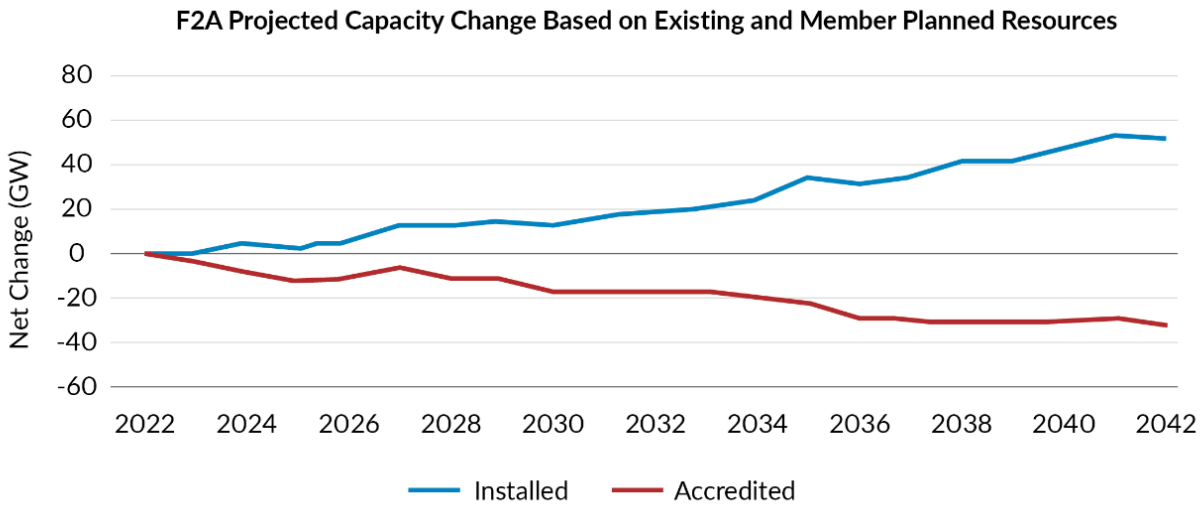
An annual planning tool called the **OMS-MISO Survey** tells a similar story. The survey compiles information about new resources utilities and states plan to build and older assets they intend to retire in the coming years. The 2023 survey shows the region's level of "committed" resources declining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

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

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

DECLINING ACCREDITED CAPACITY

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



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

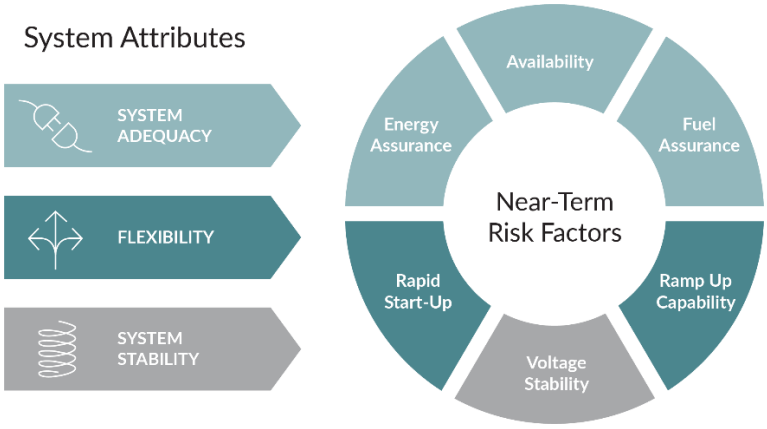
primarily wind and solar — that utilities and states plan to build in that 20-year time period.[1] But because those new wind and solar resources have significantly lower accreditation values[2] than the conventional resources that utilities and states plan to retire in the same 20-year period, the region's 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.

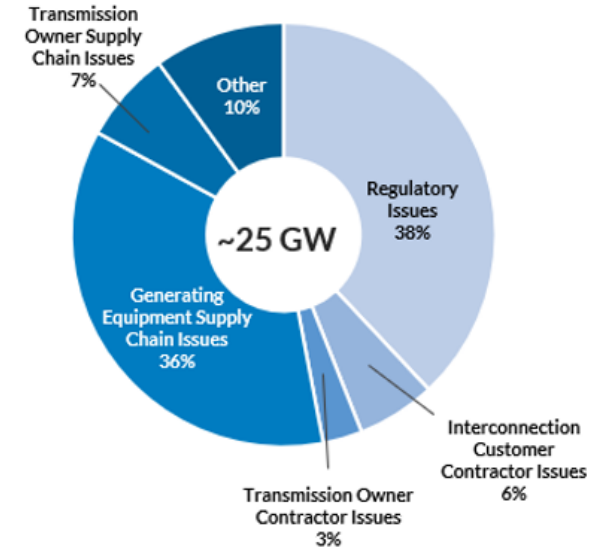
The impacts of these trends could be significant. In MISO's 2021 Electrification Insights report, MISO found that electrification could transform the region's grid from a summer-peaking to a winter-peaking system and that uncontrolled vehicle charging and daily heating and cooling load could result in 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.

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



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.

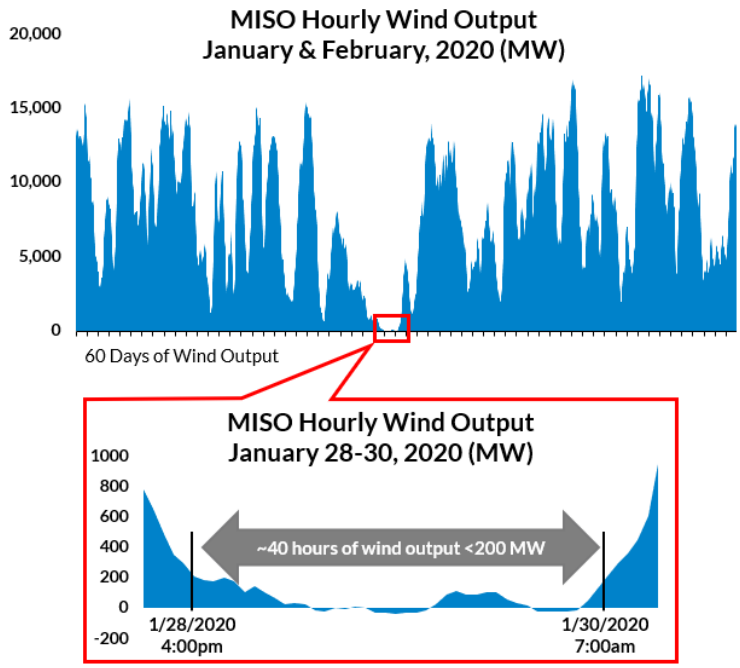
Gas-fired resources are also subject to fuel-assurance risks because they rely on pipelines to deliver gas to them. However, because the pipeline system was largely built for home-heating and manufacturing purposes, gas power plants sometimes face very challenging economic conditions to procure the fuel 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

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.

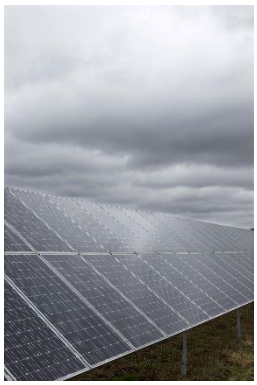
MISO and many other industry entities believe that while CCS and hydrogen co-firing technologies show promise, they are not yet viable at grid scale — and there are no assurances they will become available on EPA's optimistic timeline. If EPA's proposed rule drives coal and gas resources to retire before 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

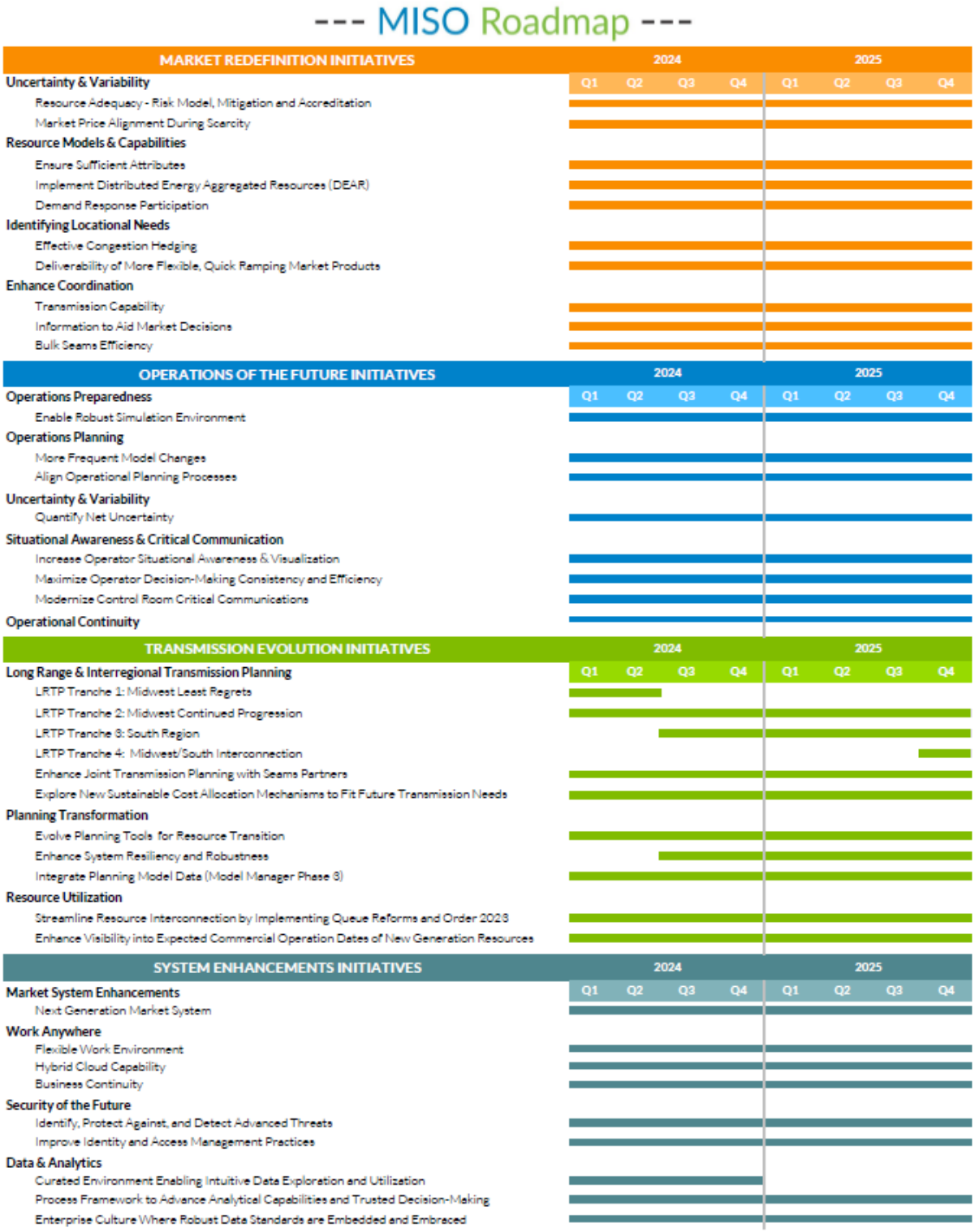
MISO's commitment to seamlessly integrating cutting-edge technologies is underpinned by a dedication to security, reliability and efficiency. This includes initiatives designed to fortify MISO's approach to cybersecurity. Refining identity and access management practices, adopting a proactive zero-trust 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'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.

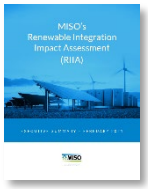
While continuing to use this conservative approach, MISO anticipates that it will create even more benefits going forward by helping its members and states to achieve their decarbonization goals in a reliable manner. In June 2022, MISO looked at those anticipated future benefits in a supplemental report 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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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-7

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

Filed September 5, 2025

Exhibit 88

August 20 weather report

The Wayback Machine - https://web.archive.org/web/20250820225303/https://weather.com/fo...

USA National Forecast

Share

Taste of Fall On The Way: Here's Who Will Feel The Big Cooldown First

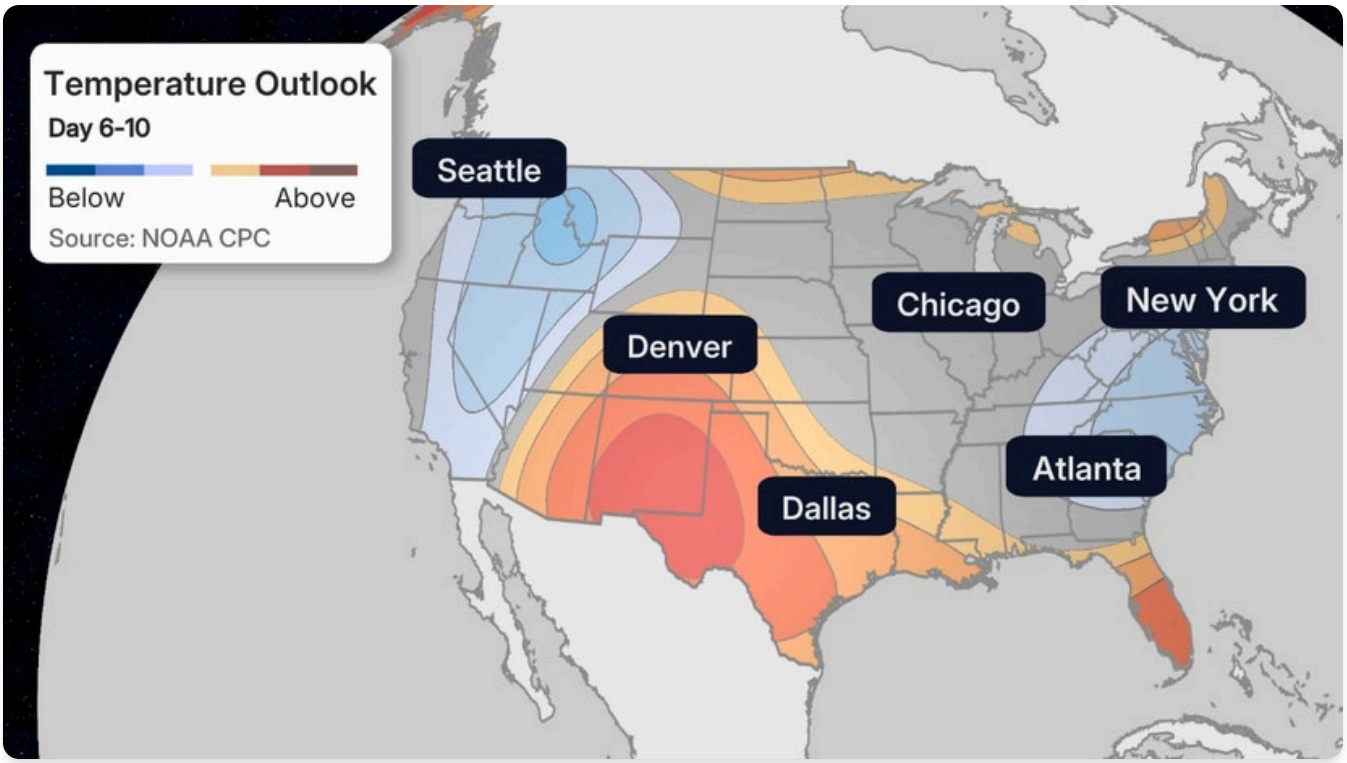
A refreshing blast of cooler air will sweep across the Plains, Midwest, and parts of the South this weekend into next week, giving millions a rare late-August taste of fall.

By Jennifer Gray • 2 hours ago

These Sled Dog Puppies Are Actually Rangers

A refreshing shot of cooler air is set to dive into the U.S. later this weekend and into next week, delivering some of the coolest temperatures of the season for millions across the country.

Who's ready for hoodies and pumpkin everything? Folks in the Midwest, Plains, and even parts of the South will get their first taste of crisp, fall-like air in the coming days.



This image shows the temperature trend for August 26-30, which shows a large pool of cool air settled over much of the Plains, Midwest and even parts of the South.

The Weather Setup

A slow-moving cold front will begin working its way into the northern U.S. Thursday and Friday. As it pushes southward and encounters the warm, humid air currently in place, showers and thunderstorms are likely to develop along the frontal boundary.

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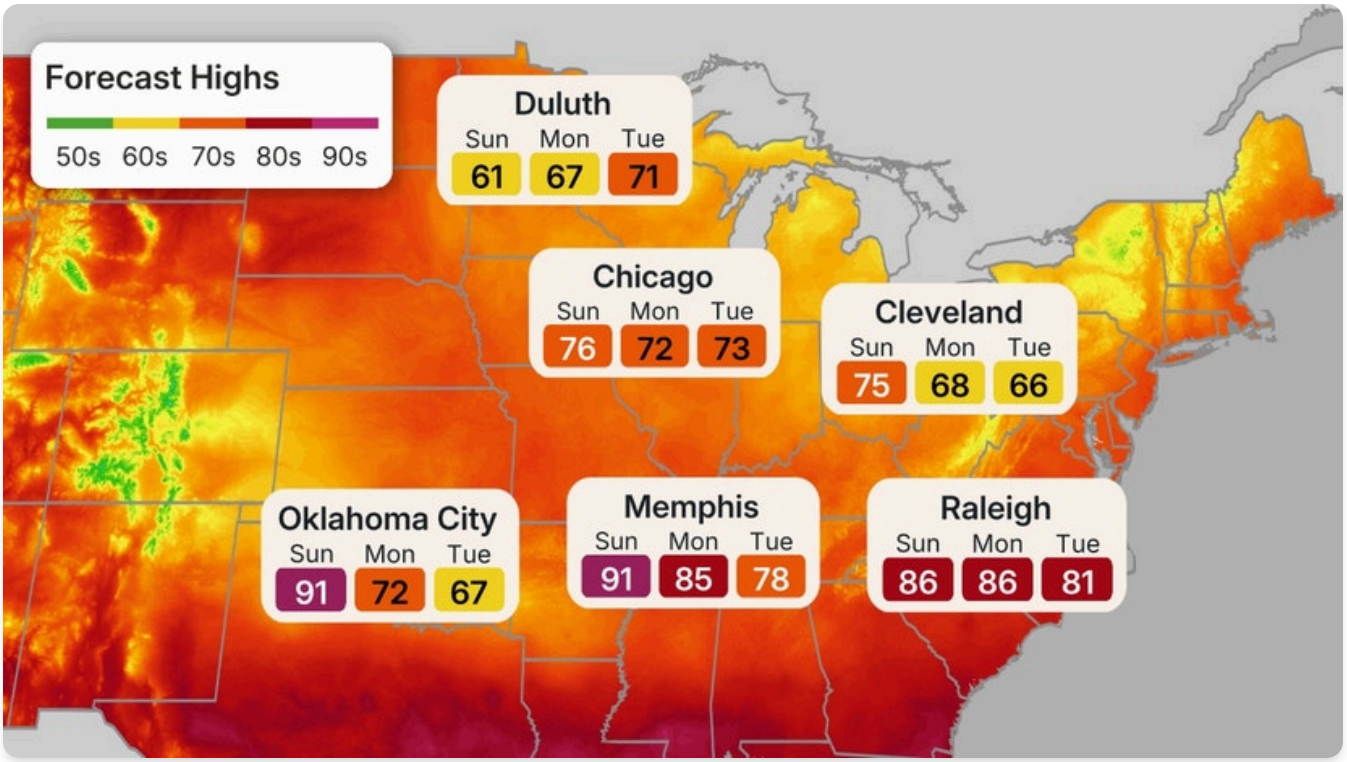
Thunderstorm Outlook
(Shaded on the map above is the likelihood of severe thunderstorms, according to NOAA's Storm Prediction Center. Note that not all categories apply for the severe weather risk on a particular day.)

The Storm Prediction Center has already highlighted areas across the Upper Midwest and Northern Plains for the potential of strong thunderstorms on Thursday.

That threat shifts farther south on Friday, as the front digs into the Central Plains and Midwest. A few of these storms could become strong to severe, so it's something to keep an eye on.

The August Chill

Behind the front, cooler, drier air will sweep across a large portion of the country. Temperatures are expected to run 10 to 25 degrees below average from the Plains to the Midwest — and even reach into parts of the South.



Three Day Temperature Outlook

Sunday: Expect highs in the 60s and lows in the 40s across parts of the upper Midwest. Duluth, Minnesota, may struggle to reach 60 degrees, while Chicago will enjoy a comfortable day around 75.

Monday: The cool air pushes farther south. Highs in the low to mid-70s will be widespread across the Plains, Midwest, Ohio Valley, interior Northeast and even in parts of the Southern Plains.

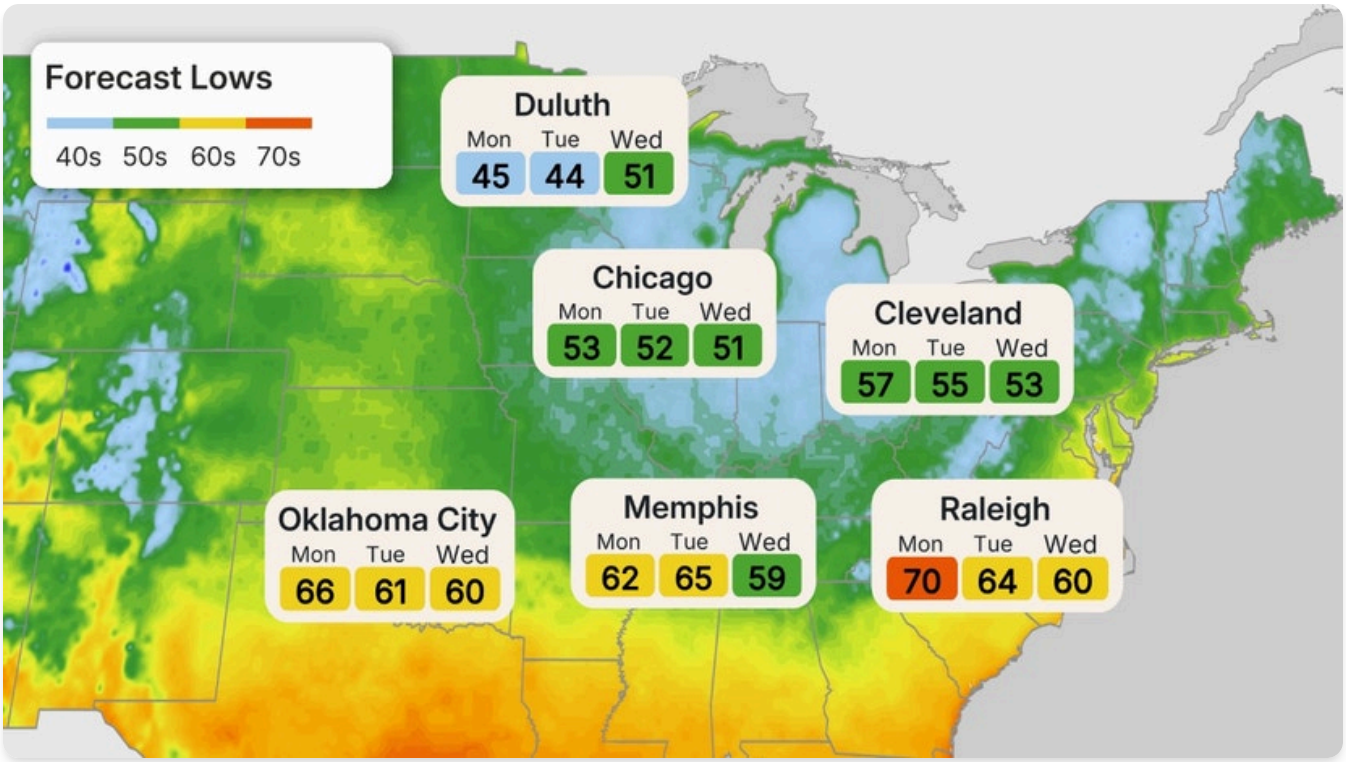
Search City or Zip Code

chance of rain in some spots.

The Ohio Valley will also enjoy highs in the low to mid-70s, with the Midwest continuing to bask in fall-like conditions.

Tuesday: By Tuesday, the cooler air won't be quite as intense, but even parts of the Southeast will feel a break from the brutal August heat.

Highs in Little Rock, Arkansas, may dip into the mid-70s, while cities like Nashville, Tennessee, could see temps in the upper 70s — not exactly sweater weather, but certainly a welcome reprieve from the dog days of summer.



Three Day Temperature Outlook

This kind of late August cool-down doesn't come around often. If you can, open the windows, head outside, and enjoy the fresh air. It may not last long, but hopefully this little taste of fall will be a welcome treat for millions.

Jennifer Gray is a weather and climate writer for weather.com. She has been covering some of the world's biggest weather and climate stories for the last two decades.

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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Exhibit to
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Public Interest Organizations

Filed September 5, 2025

Exhibit 89

2025 OMS-MISO Survey

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

Executive Summary

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.

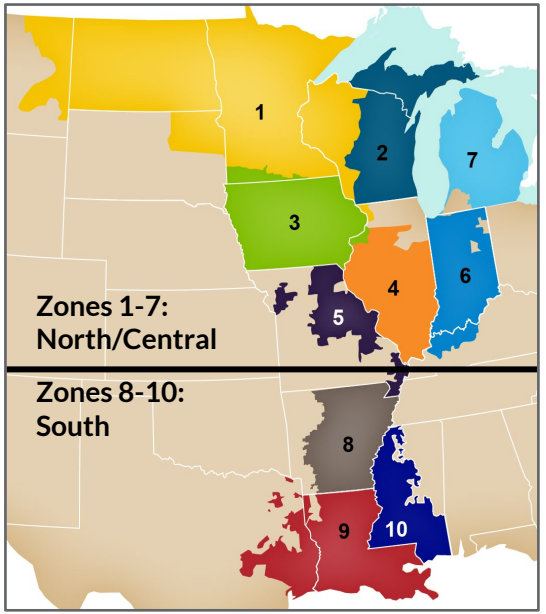
All references to capacity in this presentation indicate seasonal accredited capacity (SAC), unless noted otherwise.

*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.



*The survey serves as a point-in-time analysis based on data collected during April 2025.

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

Downside Risks

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

Upside Possibilities

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

Summer Seasonal Accreditation Values

Resource Category	2025 Survey	2024 Survey
Potentially Unavailable Resources	• No Changes	• Indicated as "Low Certainty" in survey results by market participants • Includes potential retirements or suspensions • Assumes resources will **not** be used to meet PRMR

Potential New Capacity – *New Point of Interconnection*	• **Historical Projection:** Results in **3.5 GW/yr**
	  • *Driven by 2022-2024 actuals*
	• **Emerging Projection:** Results in **6.2 GW/yr** average
	  • *Informed by member responses to OMS-MISO Survey request, these members represent 97% of the load in the footprint*
	  • *Fuel mix of new resources indicated by OMS-MISO Survey member responses*
		• **Using 3-Year Historical Average:** Capacity addition (2.3 GW/yr) based on the average new capacity built in Planning Years 2020-2022
		• **Using Alternative Projection:** Informed by timing estimates from interconnection customers with signed Generator Interconnection Agreement projects* (6.1 GW/yr)
		• Assumes resources **will** be used to meet PRMR

Replacement/ Surplus Project Impact Potential New Capacity – *Existing Point of Interconnection*	• **Replacement Impact Highlighted:** Results in additional "new resources" to offset the impacts of retirements
	• **Historical Replacement** : Valued at **1.2 GW/yr**
	  • *50% replacement & surplus queue adoption*
	• **Emerging Replacement:** Valued at **2.4 GW/yr**
	  • *100% replacement & surplus queue adoption*
	  • *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*
		• Not included

Committed Capacity	• No Changes	• Existing generation resources • External resources with firm contracts to MISO load • Assumes resources will be used to meet PRMR

PRMR: *Planning Reserve Margin Requirement*
Committed Capacity: *Resources committed to serving MISO's load*
Potentially Unavailable Resources: *May be available to serve MISO's load but may not have firm commitments*

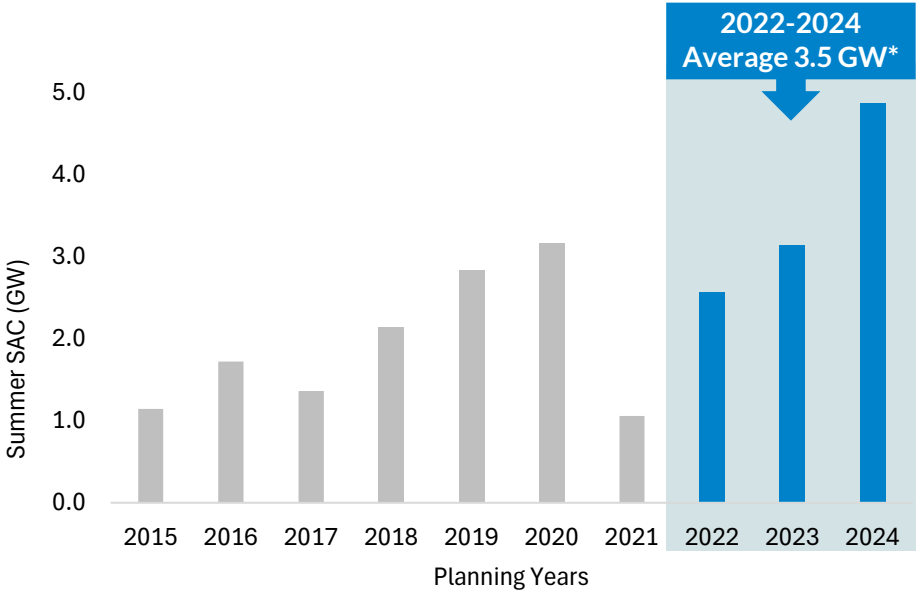
Trends and market pressures related to new capacity additions suggest that refinements are needed to better reflect uncertainty

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

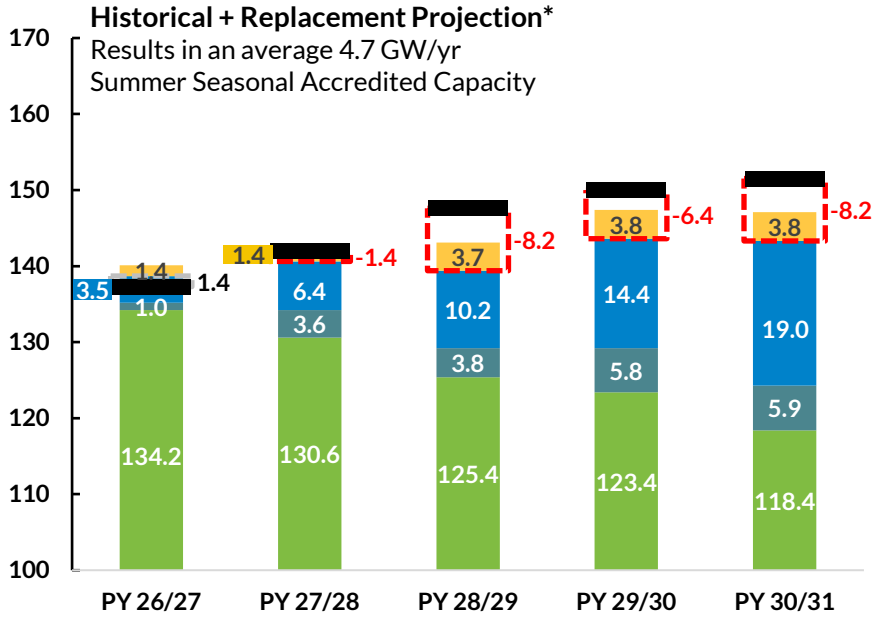


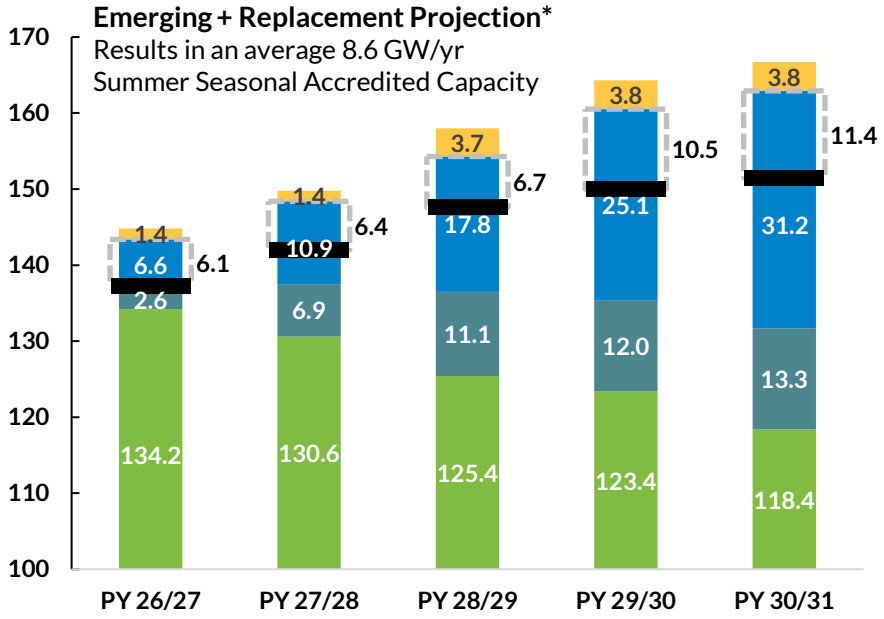
Queue applications: Nameplate 296 GW Queue & 54 GW Signed GIAs not yet online (as of 5/14/25)

**Summer seasonal accredited potential new capacity based on 2022-24 actuals*

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

MISO Resource Adequacy Projections – Summer





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

Using methods for potential New Capacity described on Slide 5

***PRMR:** Planning Reserve Margin Requirement*

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

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

Winter Seasonal Accreditation Values

Resource Category	2025 Survey	2024 Survey
Potentially Unavailable Resources	• No Changes	• Indicated as "Low Certainty" in survey results by market participants • Includes potential retirements or suspensions • Assumes resources will **not** be used to meet PRMR

Potential New Capacity – New Point of Interconnection	• **Historical Projection:** Results in **1.4 GW/yr**
	  • *Driven by 2022-2024 actuals*
	• **Emerging Projection:** Results in **4.1 GW/yr** average
	  • *Informed by member responses to OMS-MISO Survey request, these members represent 97% of the load in the footprint*
	  • *Fuel mix of new resources indicated by OMS-MISO Survey member responses*
		• Not included

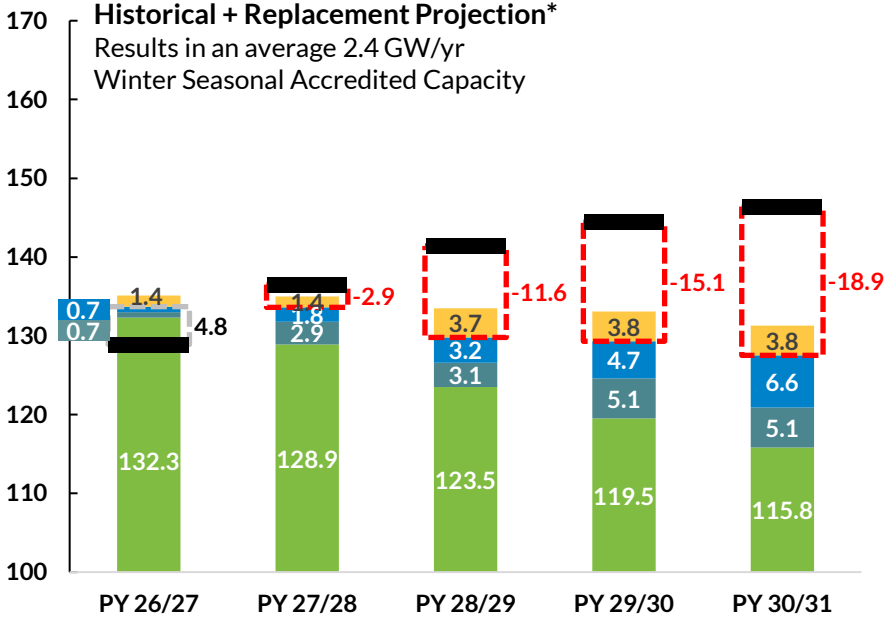
Replacement/ Surplus Project Impact Potential New Capacity – Existing Point of Interconnection	• **Replacement Impact Highlighted:** Results in additional "new resources" to offset the impacts of retirements
	• **Historical Replacement** : Valued at **1.0 GW/yr**
	  • *50% replacement & surplus queue adoption*
	• **Emerging Replacement :** Valued at **2.1 GW/yr**
	  • *100% replacement & surplus queue adoption*
	  • *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*
		• Not included

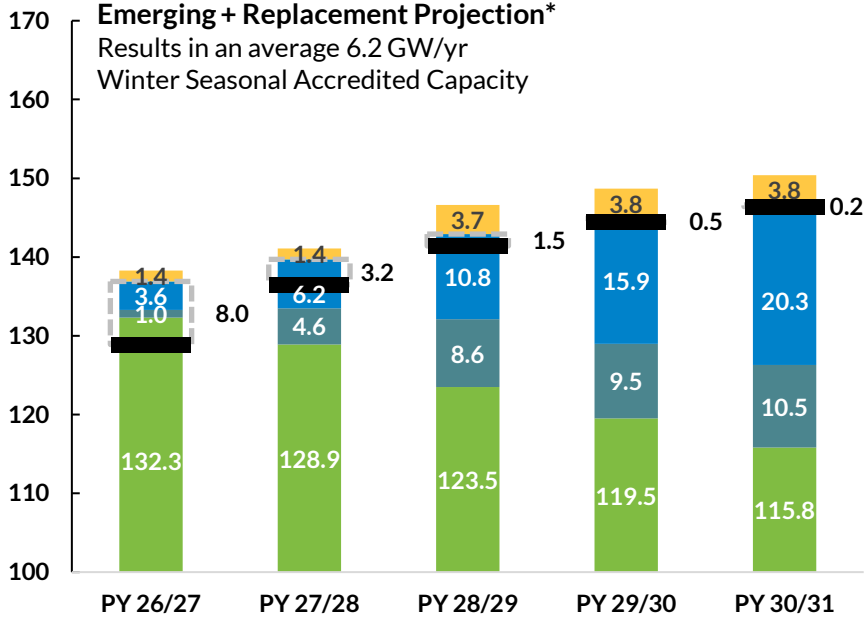
Committed Capacity	• No Changes	• Existing generation resources • External resources with firm contracts to MISO load • Assumes resources will be used to meet PRMR

PRMR: *Planning Reserve Margin Requirement*
Committed Capacity: *Resources committed to serving MISO's load*
Potentially Unavailable Resources: *May be available to serve MISO's load but may not have firm commitments*

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

MISO Resource Adequacy Projections – Winter





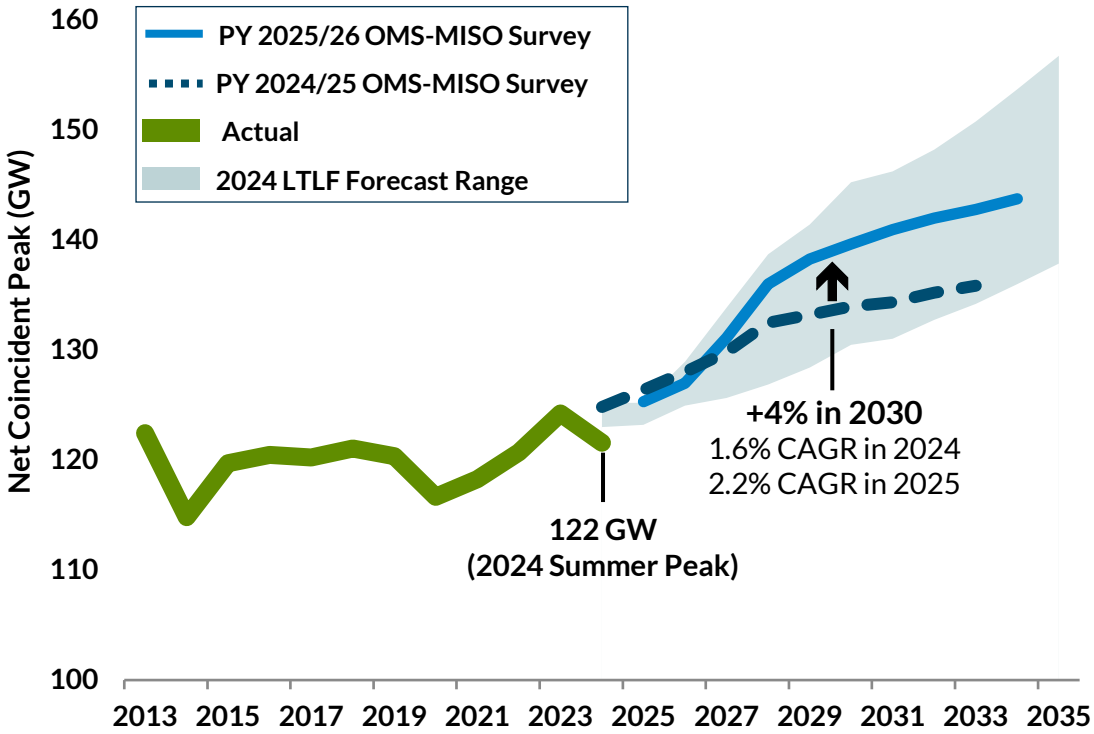
Projected PRMR with LSE forecast
Potentially Unavailable Resources
Potential New Capacity
Value of Replacement/Surplus Projects
Committed Capacity

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

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

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

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



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

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

Data Centers (149-241)

Electric Vehicles (54-91)

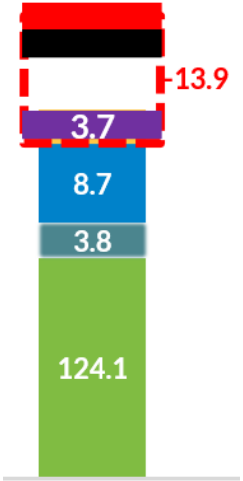
Industry Development & Offshoring (21-105)

Hydrogen (25-95)

Building Electrification (36-43)

LTLF: Long-Term Load Forecast, 2024 Long-Term Load Forecast White Paper; **CAGR:** Compound Annual Growth Rate
**Level of certainty based on expected likelihood of load growth materializing*

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 Forecast[1]
- 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"

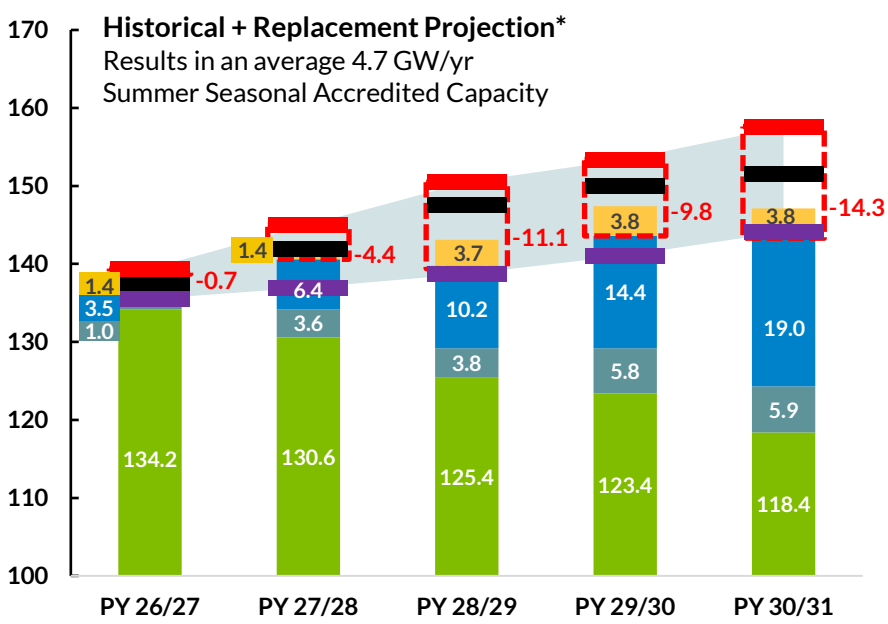
- Models lower load-growth scenario per Long-Term Load Forecast[1]

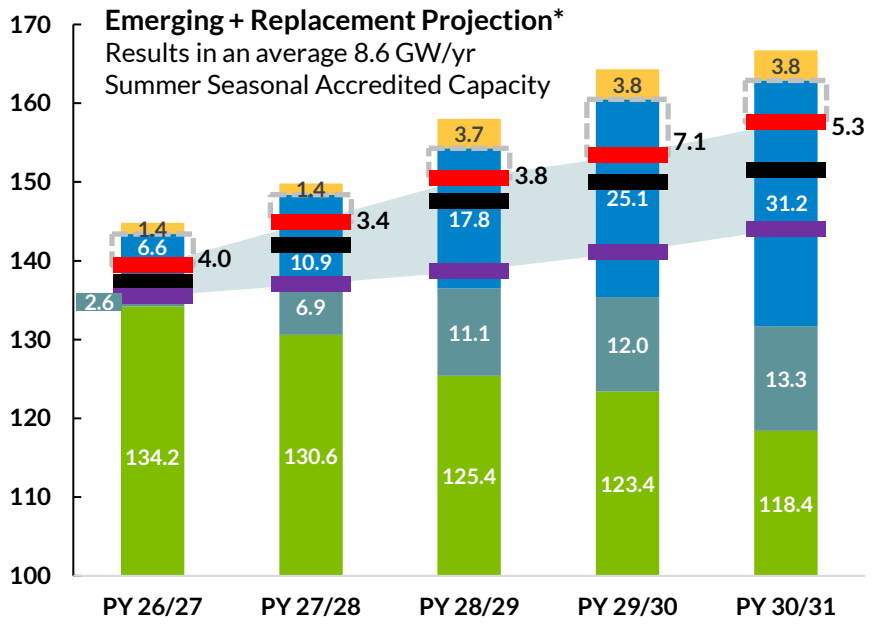
[1] MISO Long-Term Load Forecast White Paper, December 2024

PRMR: *Planning Reserve Margin Requirement* ***LSE:*** *Load Serving Entity* ***LOLE:*** *Loss of Load Expectation*

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

MISO Resource Adequacy Projections – Summer





Planning Reserve Margin

- 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*

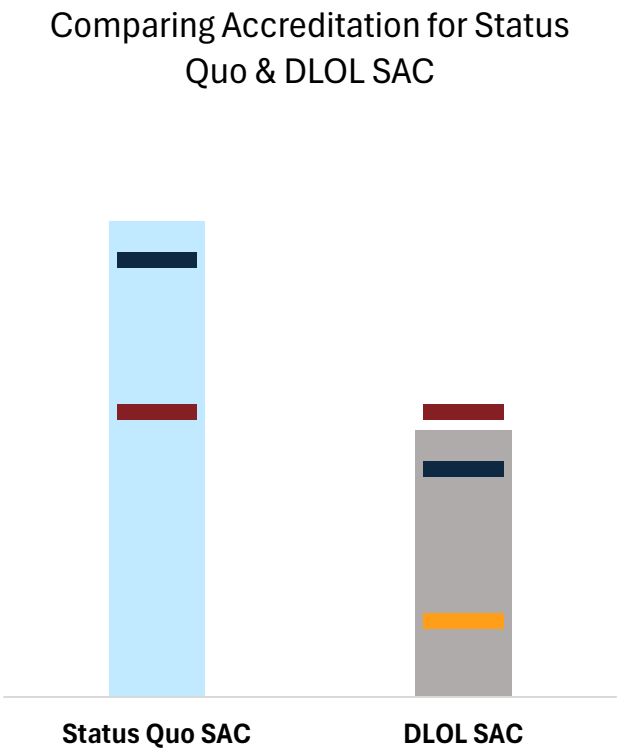
MISO's existing accreditation methods can overstate a resource's capacity value during the highest risk periods, especially as the region's risk profile changes, leading to understated risk

- 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.

*See Resource Accreditation White Paper, published March 2024

High Level Description of Status Quo vs Direct Loss of Load



Peak Load Forecast
- Submitted annually by members

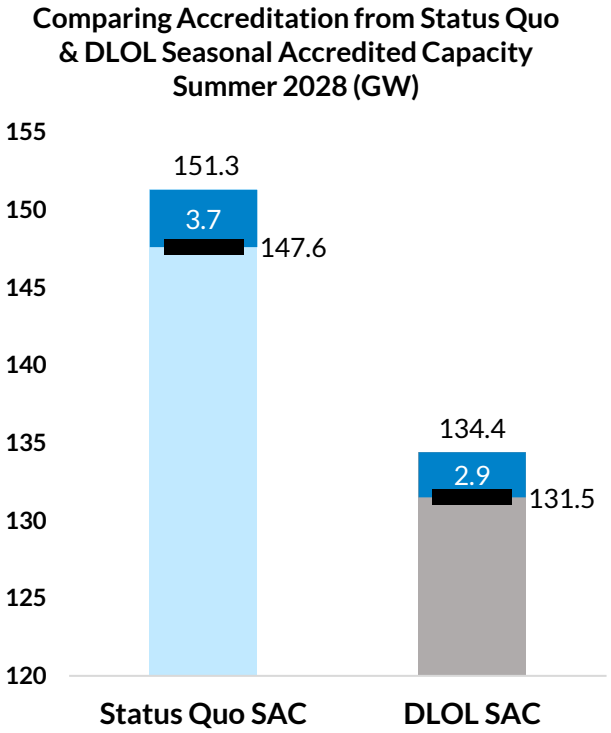
Critical Hours Load Forecast
- Illustrative only, not collected

Planning Reserve Margin Requirement (PRMR) at
- Status Quo: Peak Load
- DLOL: critical hours

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

DLOL SAC value of Resources during critical hours to meet PRMR

Status Quo vs Direct Loss of Load Accreditation for summer 2028



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

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

Key Takeaways

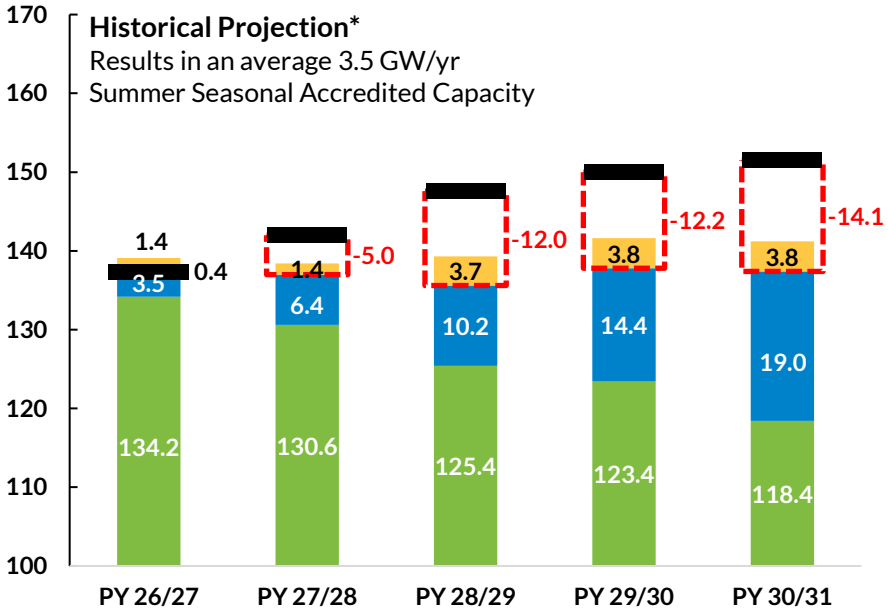
The 2025 OMS-MISO Survey emphasizes that decisions made today by utilities, regulators, MISO and its members will critically shape future resource adequacy

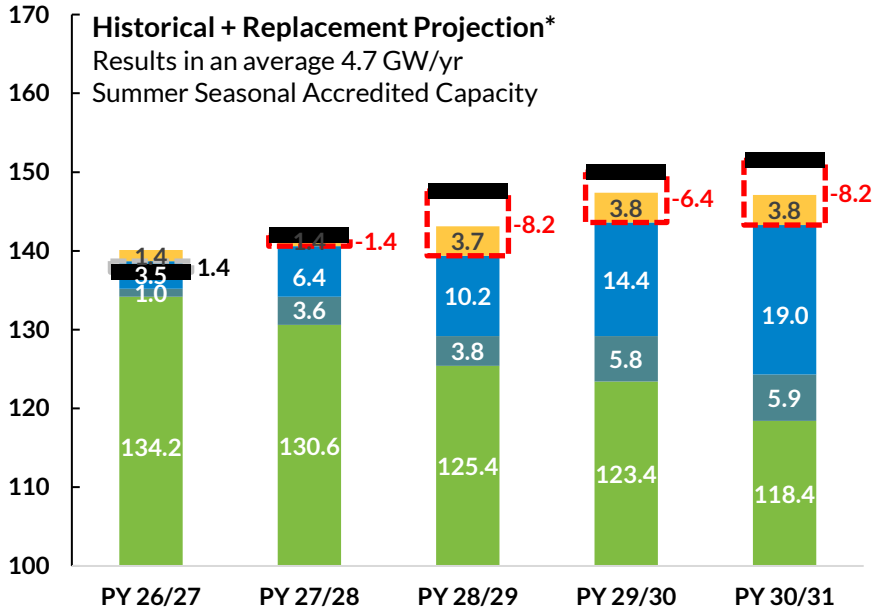
- This year's survey highlights significant uncertainty in projected resource adequacy, underscoring the urgent need for accelerated resource additions, strategic retirement planning, and proactive management of increasing load growth.
- Ongoing collaboration between OMS and MISO remains essential to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

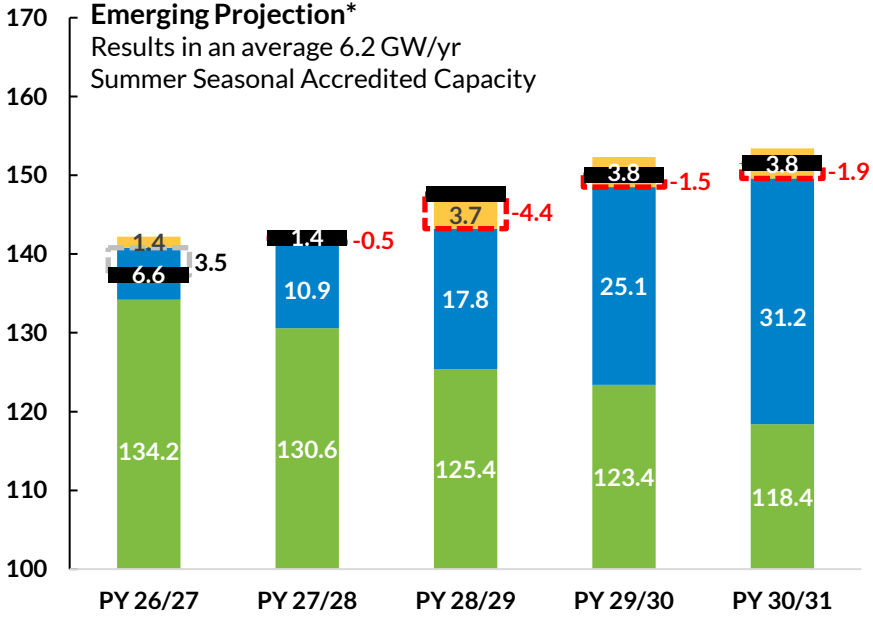
Using methods for potential New Capacity described on Slide 5
***PRMR:** Planning Reserve Margin Requirement*

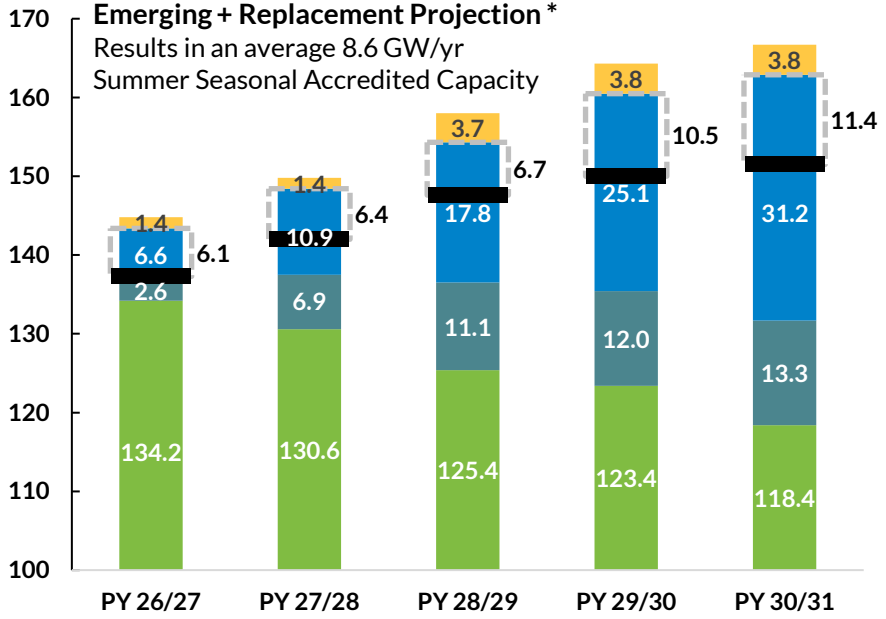
Red border values indicate the additional potential deficit against the Projected PRMR
Gray border values indicate the potential surplus against the Projected PRMR

- 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

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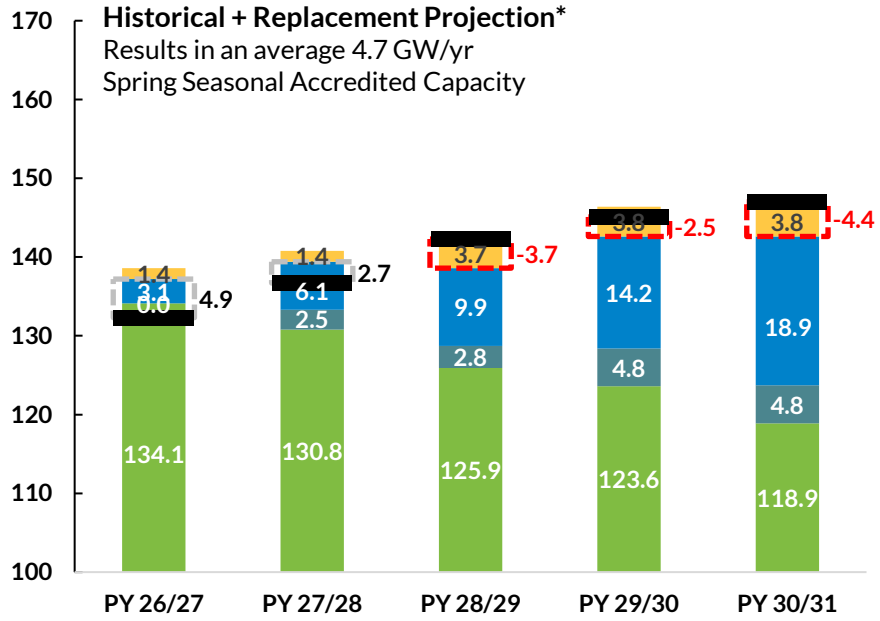
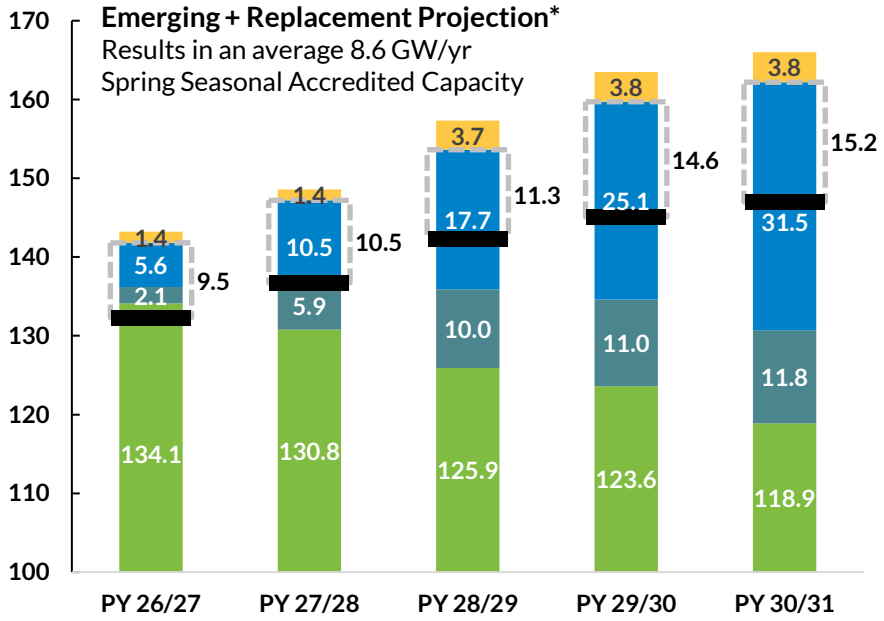
Historical + Replacement & Emerging + Replacement Projections vs PRMR ~4.7 GW & 8.6 GW Status Quo Fall SAC Installation Rate

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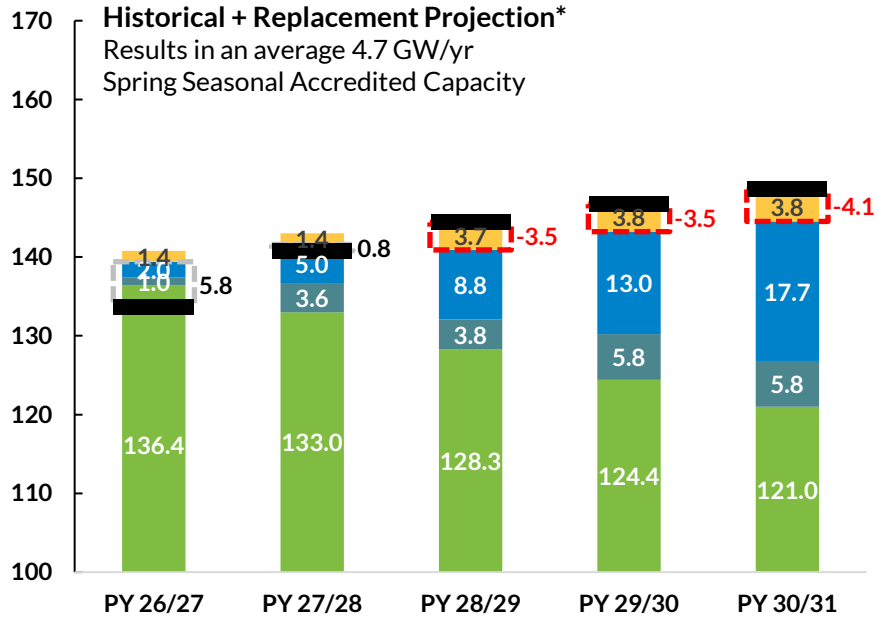
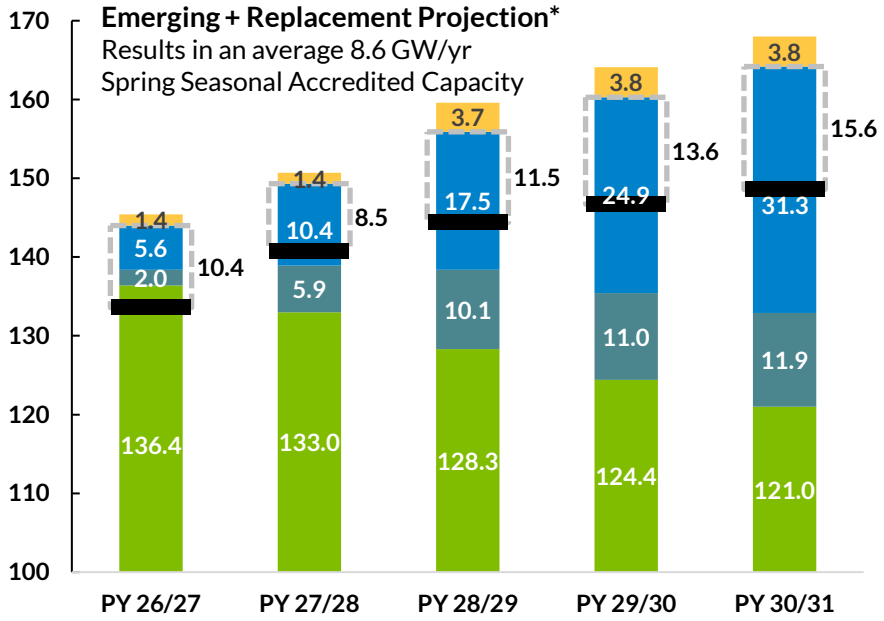
Historical + Replacement & Emerging + Replacement Projections vs PRMR ~4.7 GW & 8.6 GW Status Quo Spring SAC Installation Rate

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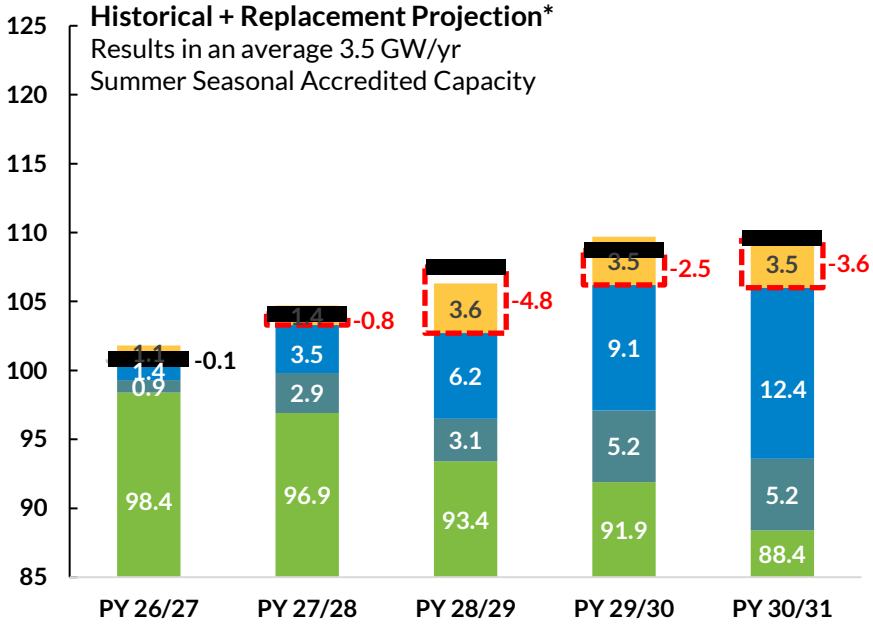
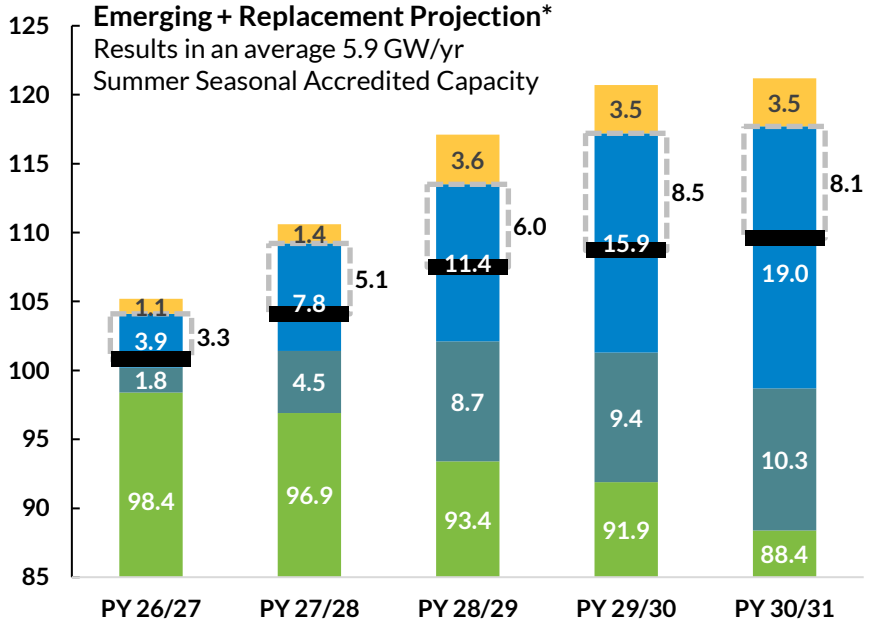
Historical + Replacement & Emerging + Replacement Projections vs PRMR ~4.7 GW & 8.6 GW Status Quo Summer SAC Installation Rate

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

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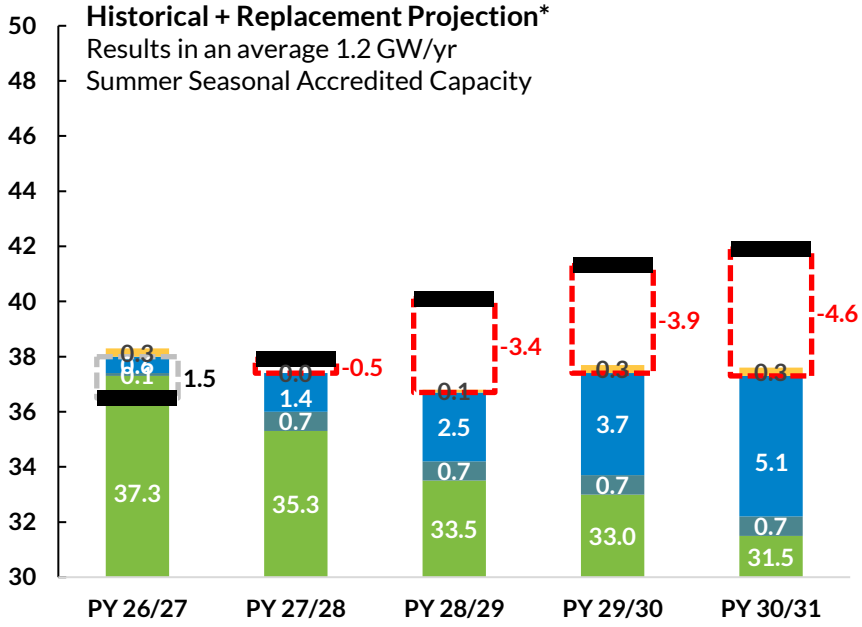
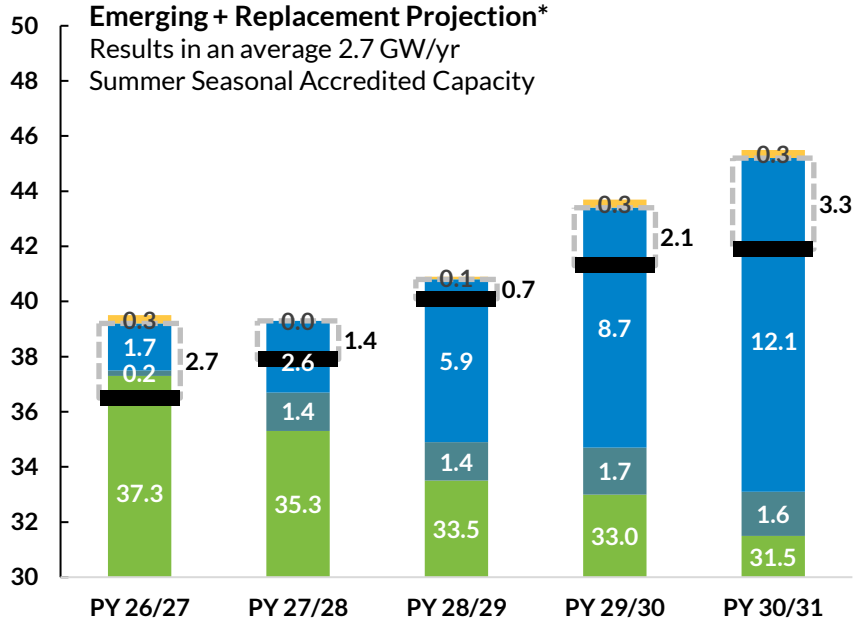
Historical + Replacement & Emerging + Replacement Projections vs PRMR ~4.7 GW & 8.6 GW Status Quo Summer SAC Installation Rate

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

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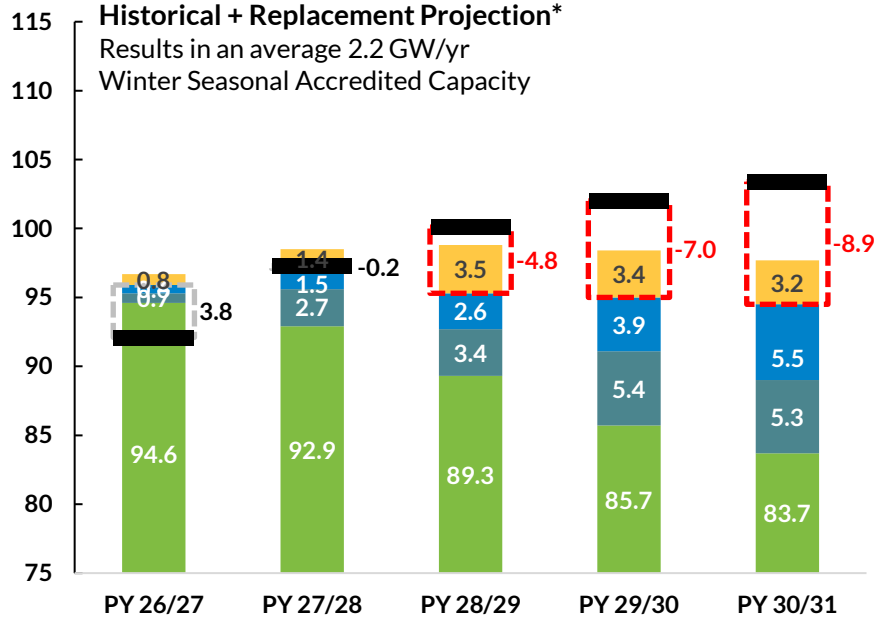
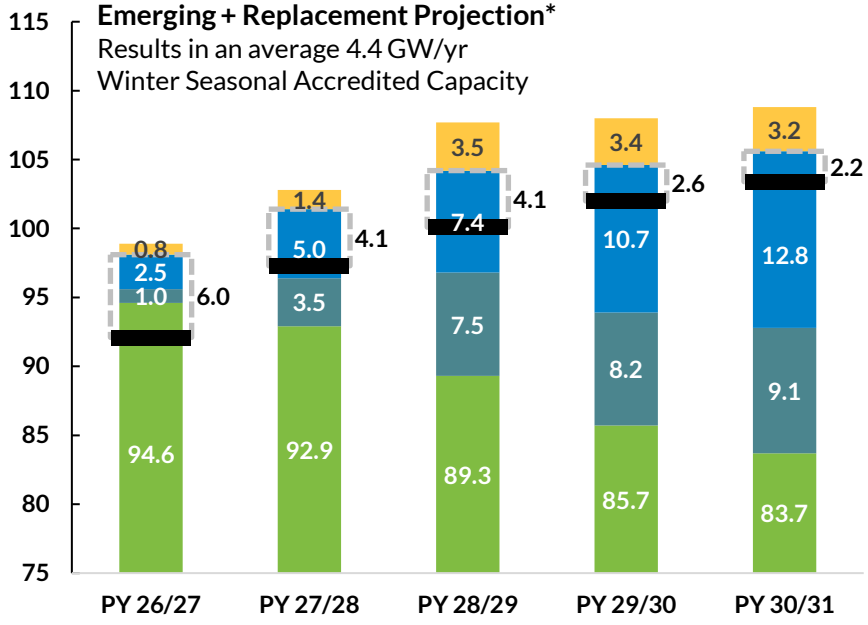
Historical + Replacement & Emerging + Replacement Projections vs PRMR
~2.4 GW & 6.2 GW Status Quo Winter SAC Installation Rate

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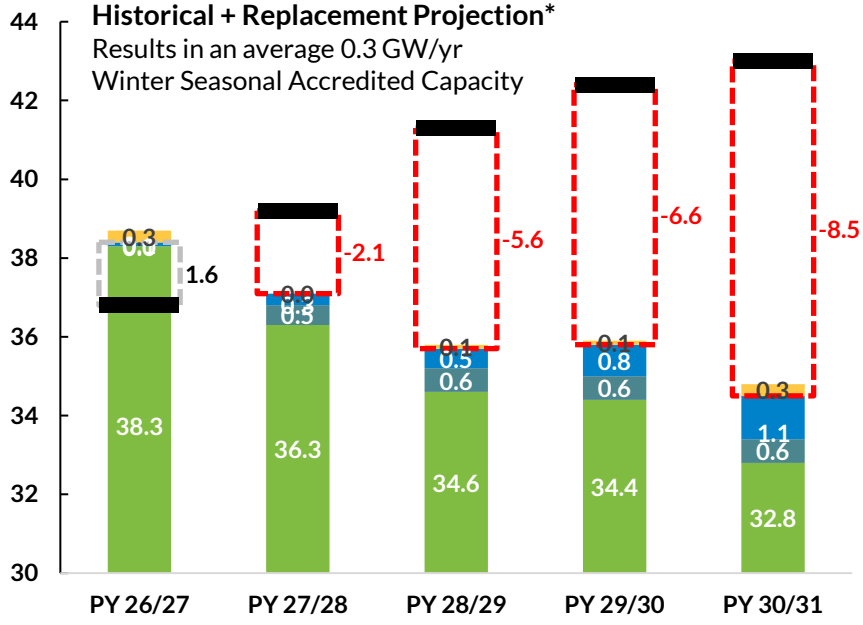
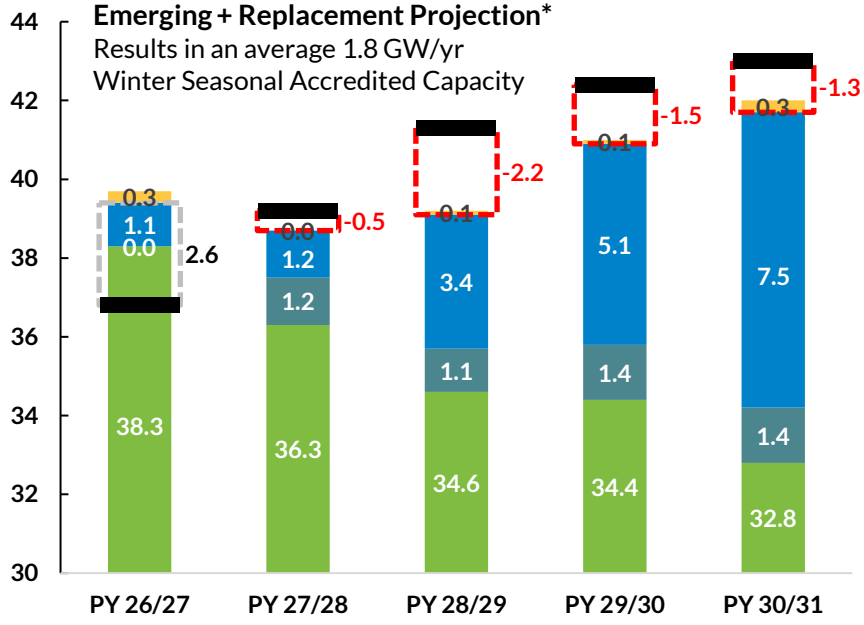
Historical + Replacement & Emerging + Replacement Projections vs PRMR ~2.4 GW & 6.2 GW Status Quo Winter SAC Installation Rate

MISO Resource Adequacy Projections – Winter MISO South





Projected PRMR with LSE forecast
Potentially Unavailable Resources
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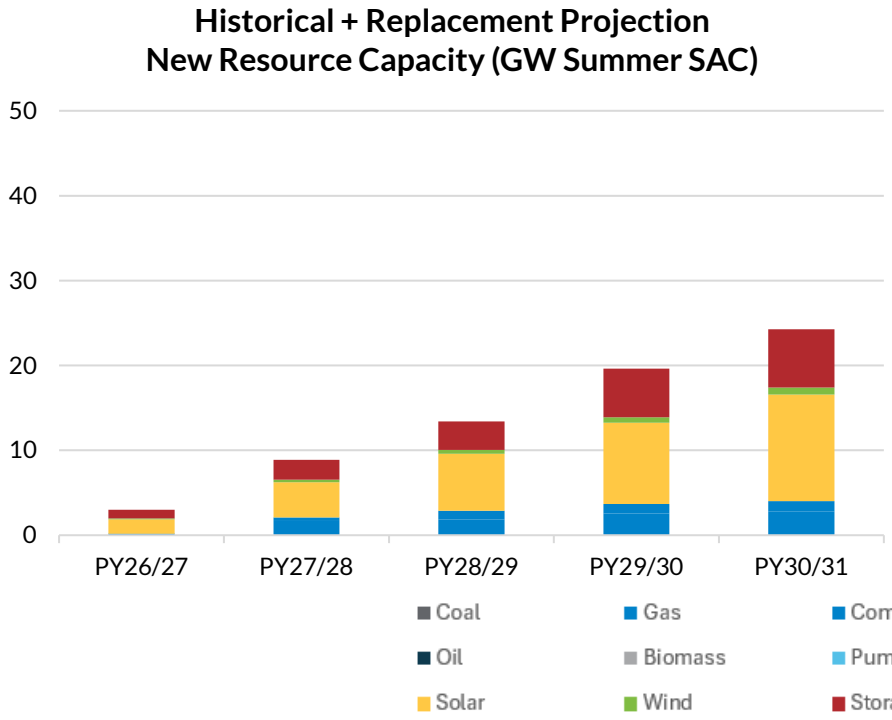
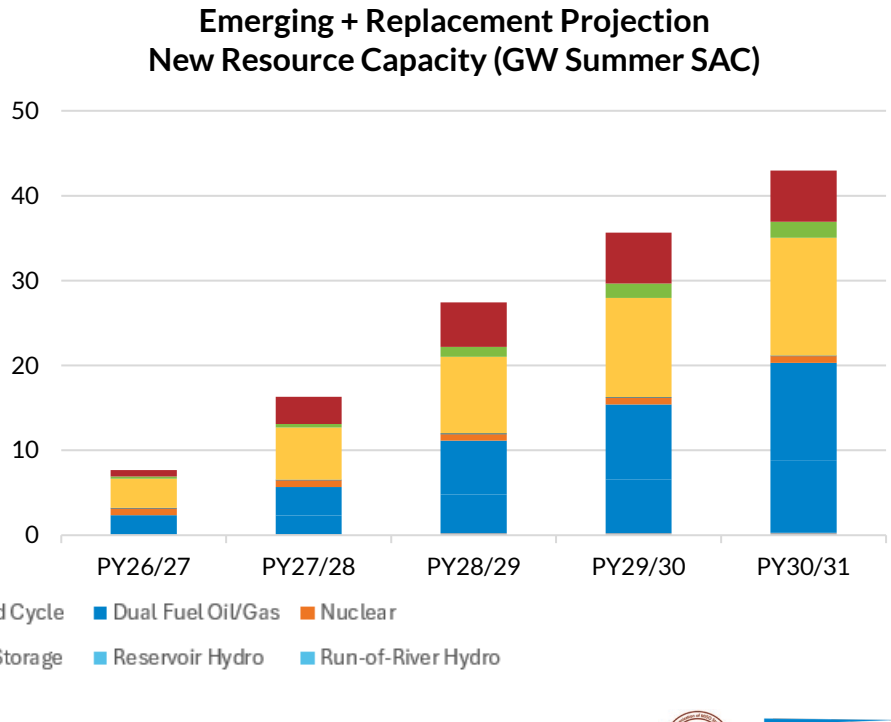
OMS-MISO Survey projections of new resource accreditation value -Status Quo SAC calculations

Projections of New Resource Fuel Mix – Summer



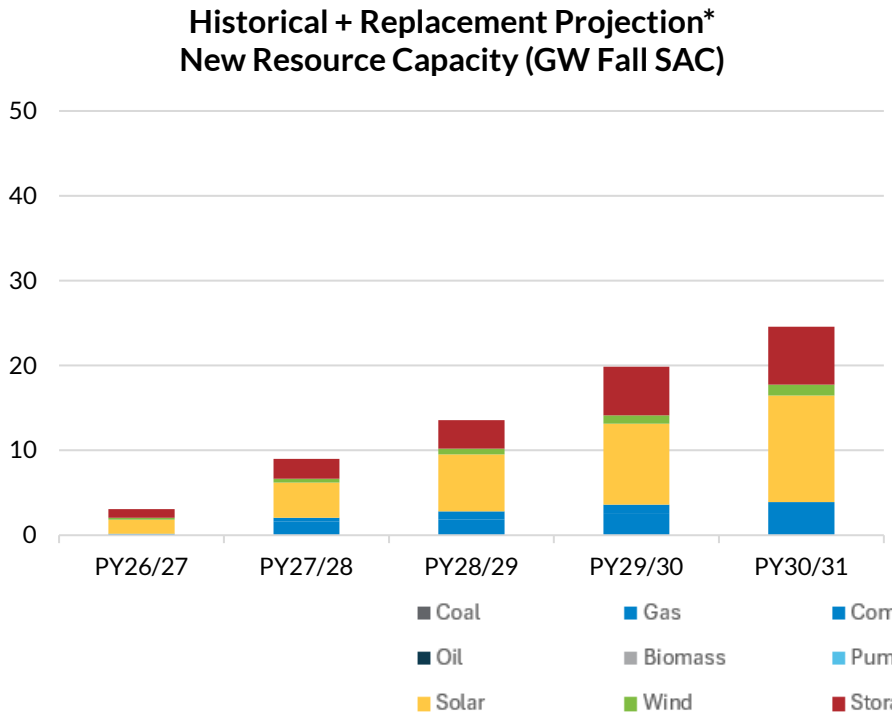


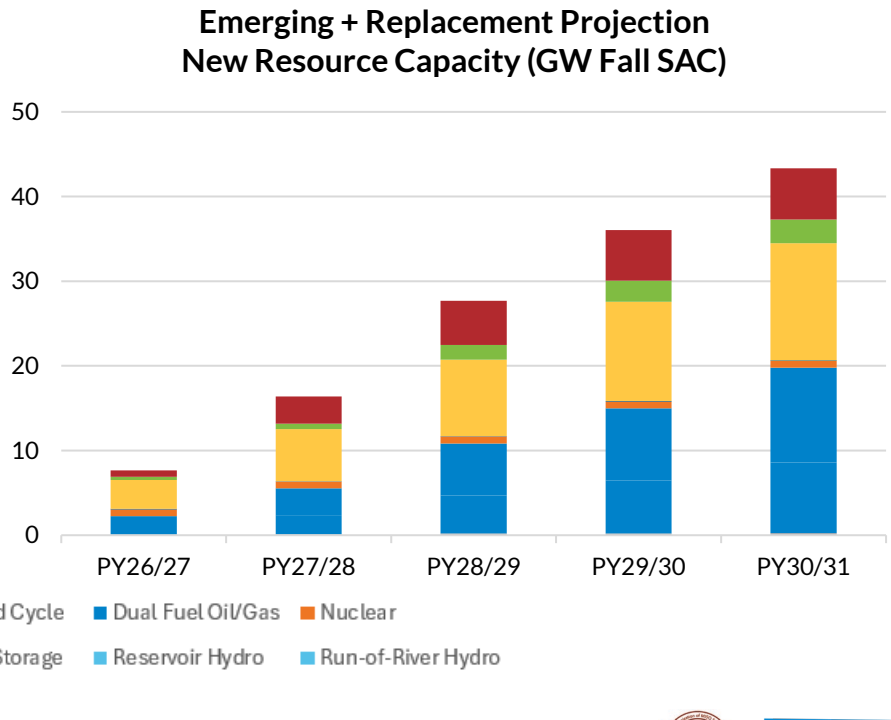
Coal | Gas | Combined Cycle | Dual Fuel Oil/Gas | Nuclear
Oil | Biomass | Pumped Storage | Reservoir Hydro | Run-of-River Hydro
Solar | Wind | Storage

SAC: *Seasonal Accredited Capacity*
All values are cumulative, and are based upon average fuel type resource accreditation from Planning Year 2025/26

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

Projections of New Resource Fuel Mix – Fall





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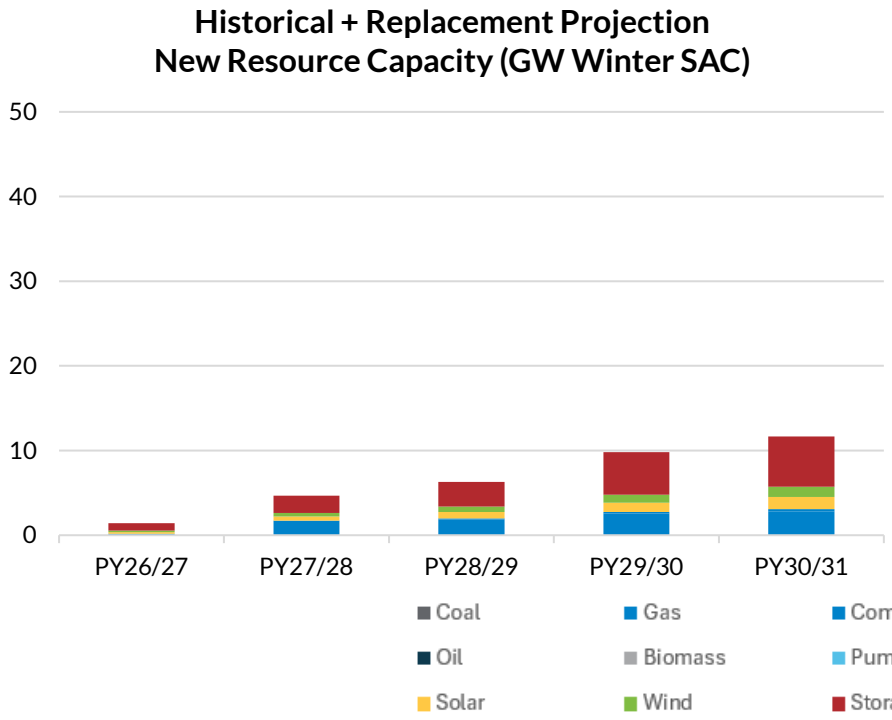
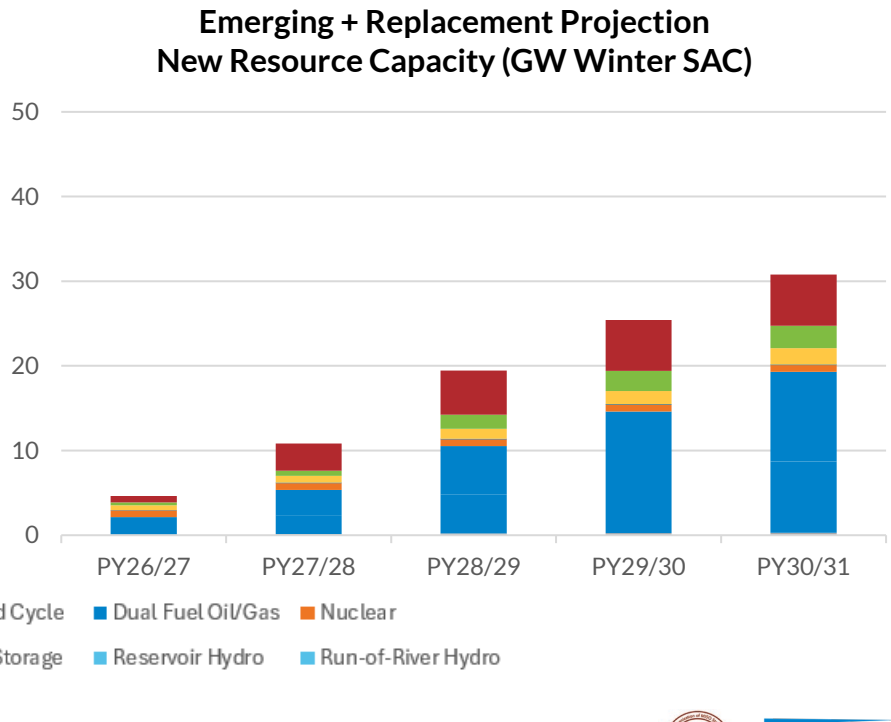
OMS-MISO Survey projections of new resource accreditation value -Status Quo SAC calculations

Projections of New Resource Fuel Mix – Winter





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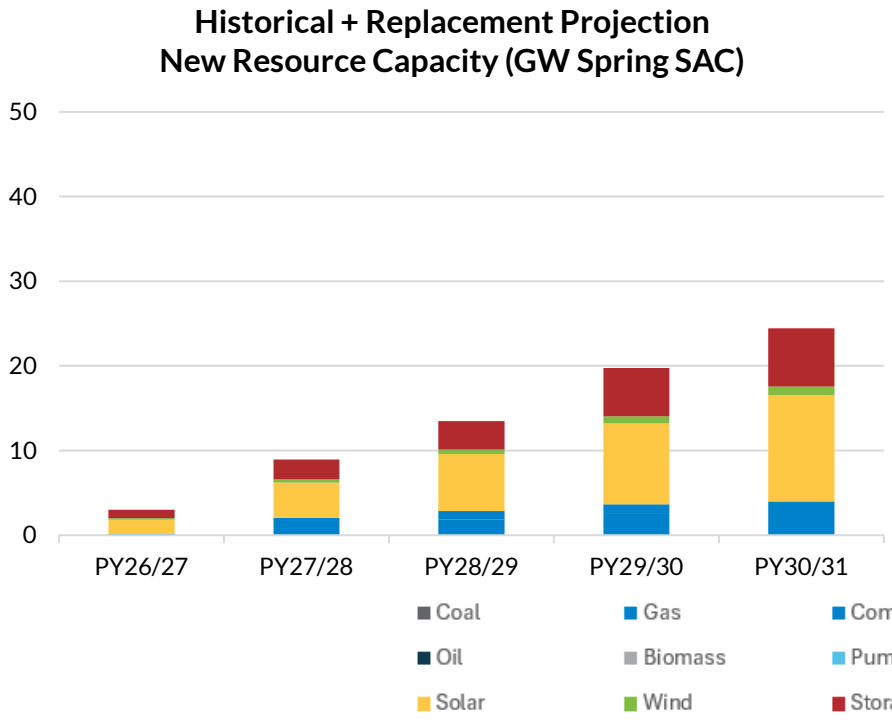
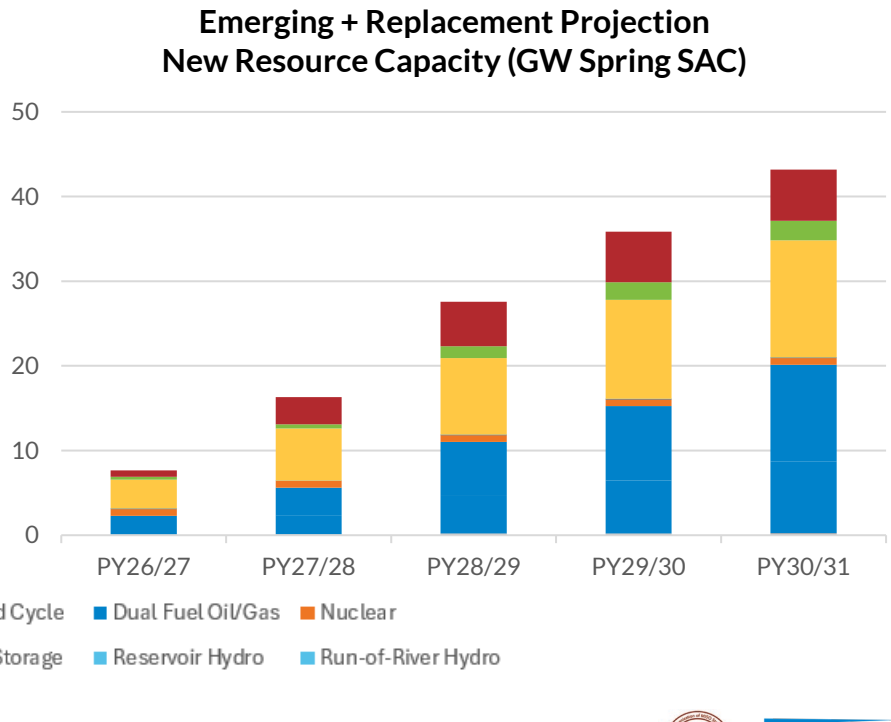
Projections of New Resource Fuel Mix – Spring





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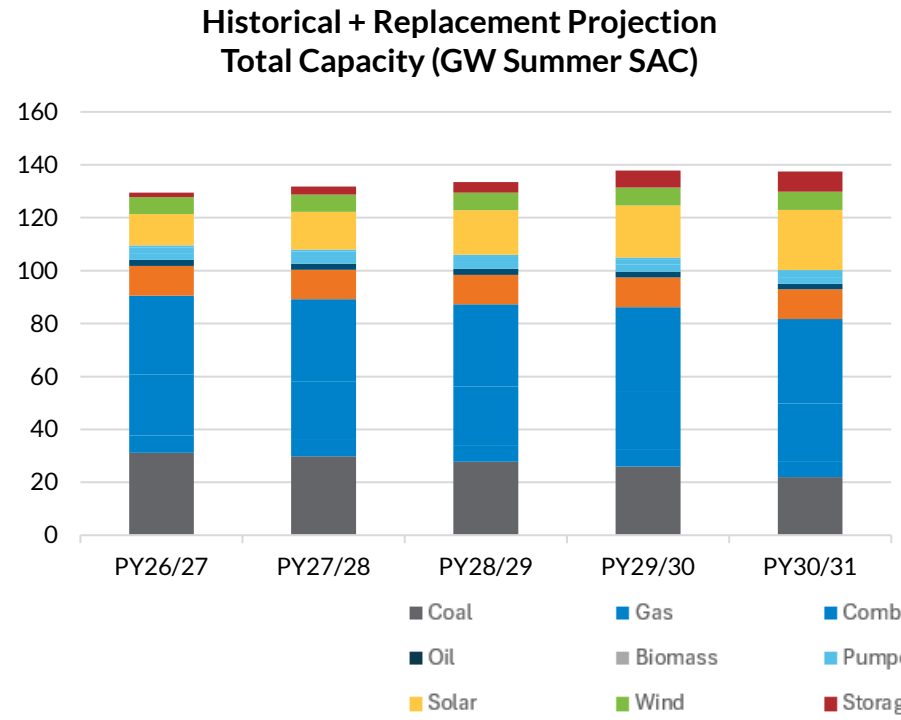
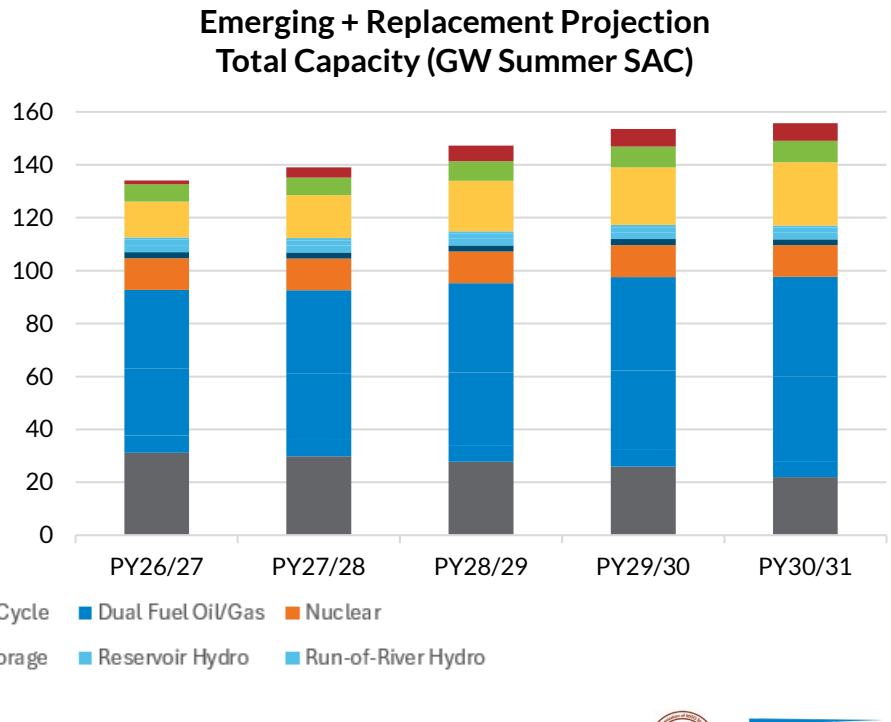
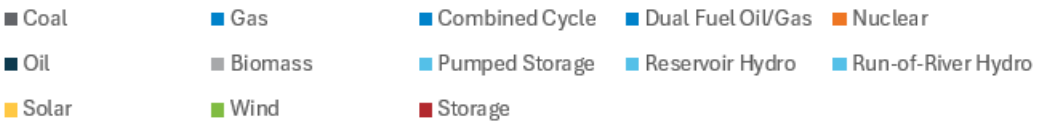
OMS-MISO Survey projections of fleet total resource accreditation value -Status Quo SAC calculations

Combined Projections of Fuel Mix – Summer



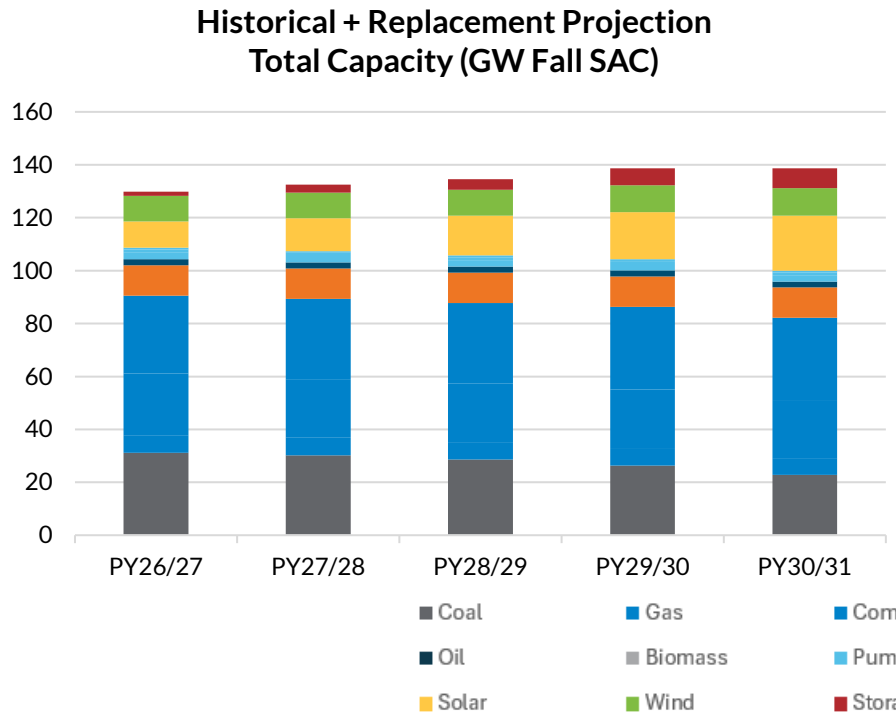


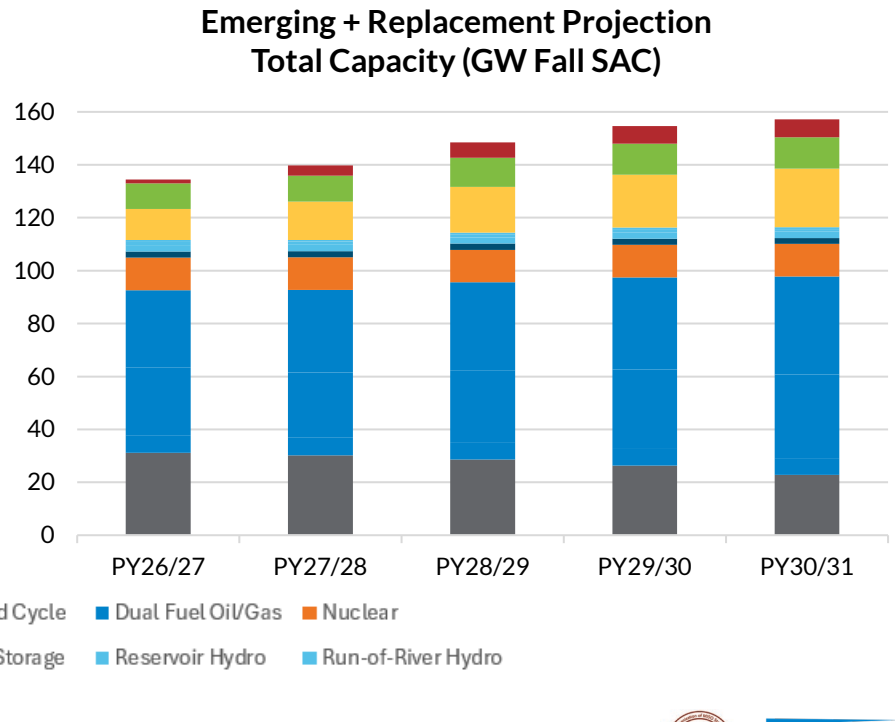


SAC: *Seasonal Accredited Capacity*
New resources are based upon average fuel type resource accreditation from Planning Year 2025/26, existing based on seasonal Status Quo SAC

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

Combined Projections of Fuel Mix – Fall





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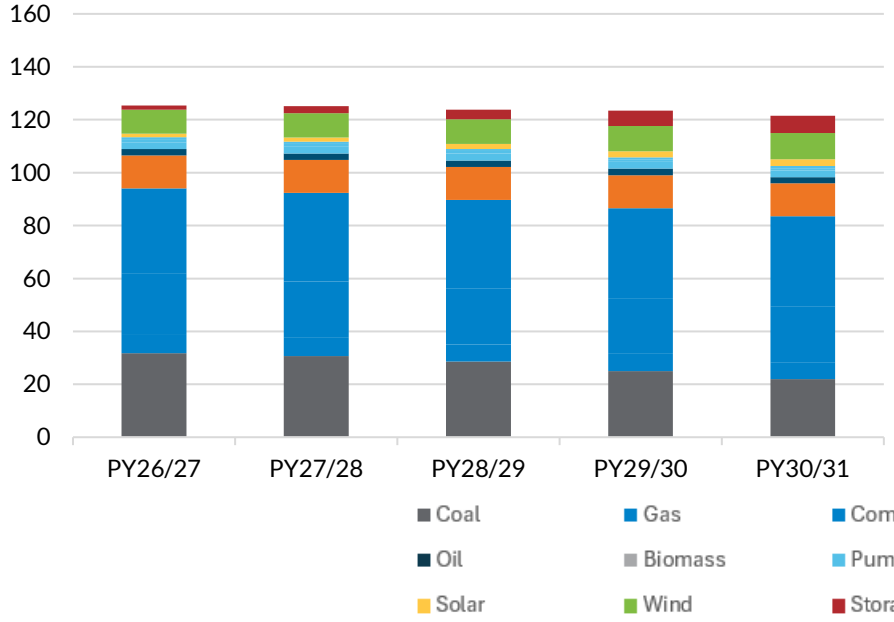
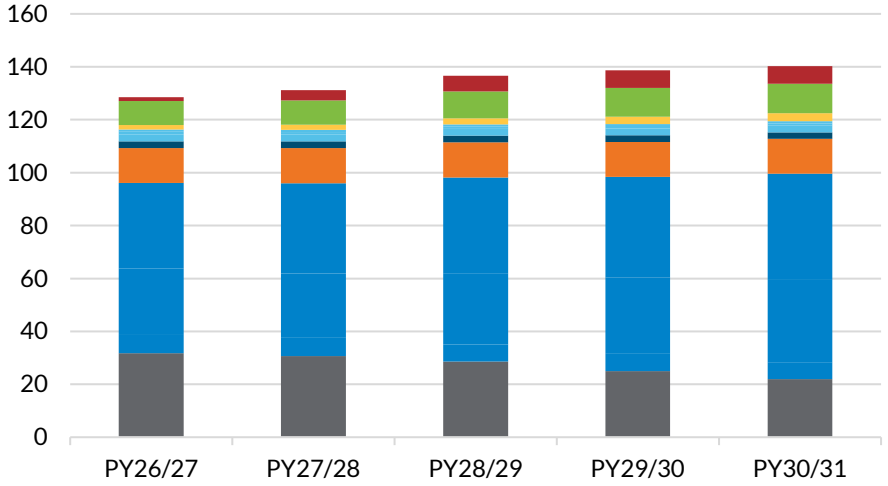
OMS-MISO Survey projections of fleet total resource accreditation value -Status Quo SAC calculations

Combined Projections of Fuel Mix – Winter

Historical + Replacement Projection
Total Capacity (GW Winter SAC)



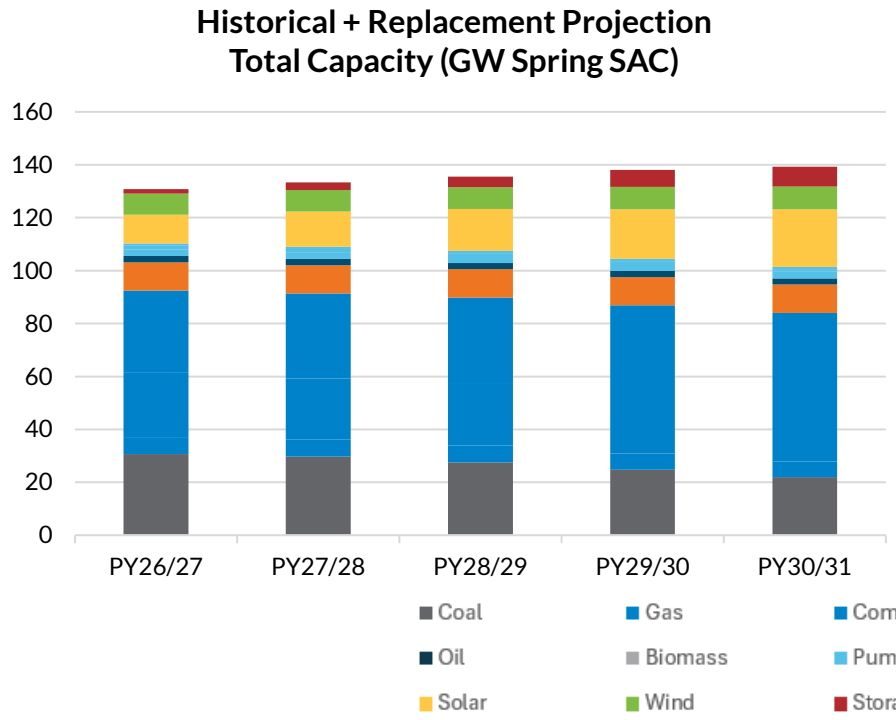
Emerging + Replacement Projection
Total Capacity (GW Winter SAC)

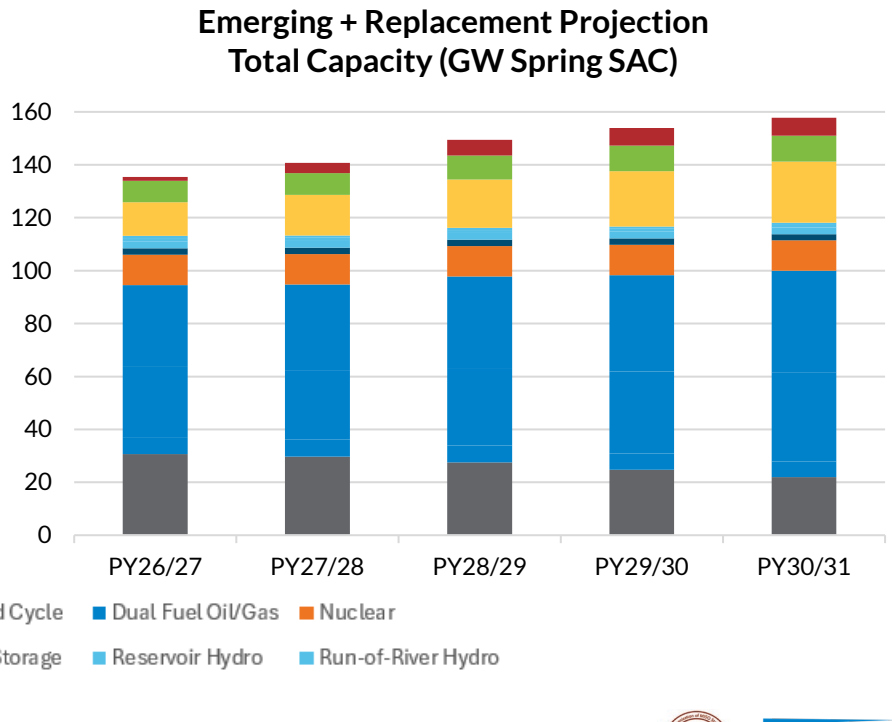


SAC: *Seasonal Accredited Capacity*
New resources are based upon average fuel type resource accreditation from Planning Year 2025/26, existing based on seasonal Status Quo SAC

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

Combined Projections of Fuel Mix – Spring



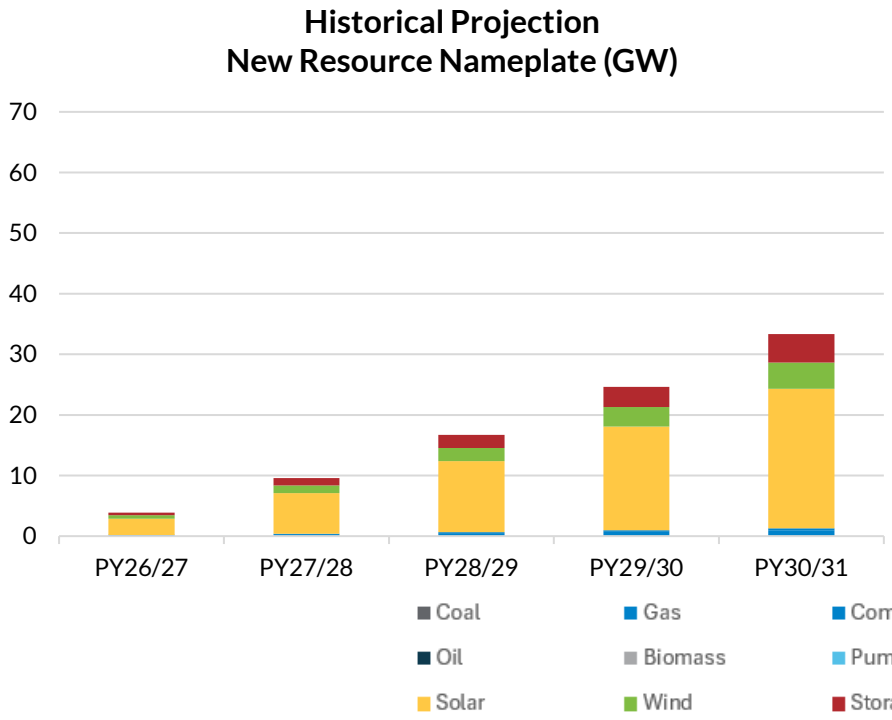


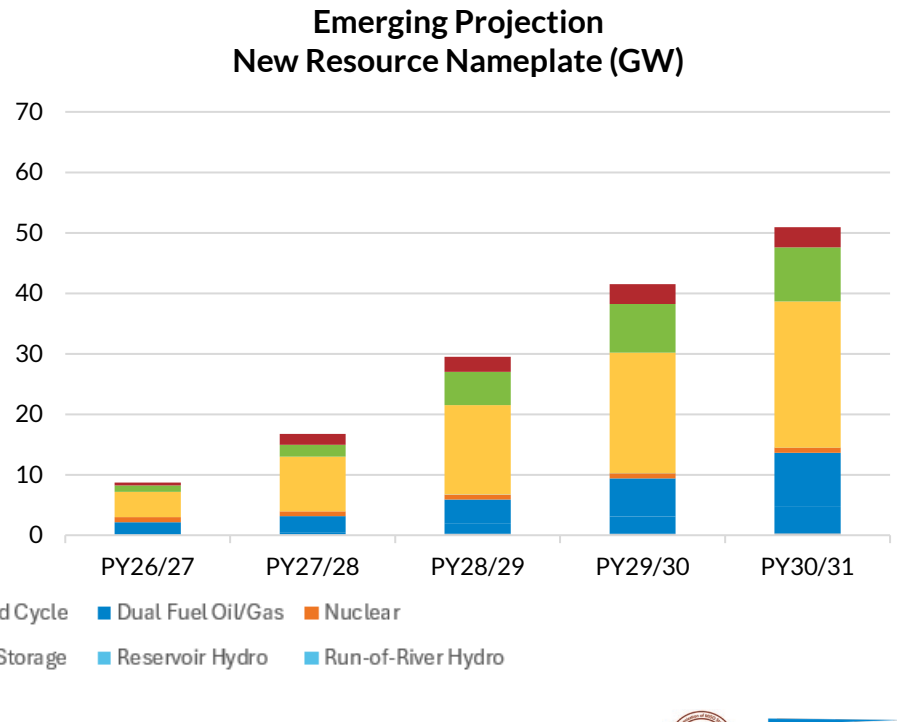
Coal | Gas | Combined Cycle | Dual Fuel Oil/Gas | Nuclear
Oil | Biomass | Pumped Storage | Reservoir Hydro | Run-of-River Hydro
Solar | Wind | Storage

SAC: *Seasonal Accredited Capacity*
New resources are based upon average fuel type resource accreditation from Planning Year 2025/26, existing based on seasonal Status Quo SAC

OMS-MISO Survey projections of new resource deliverable nameplate

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





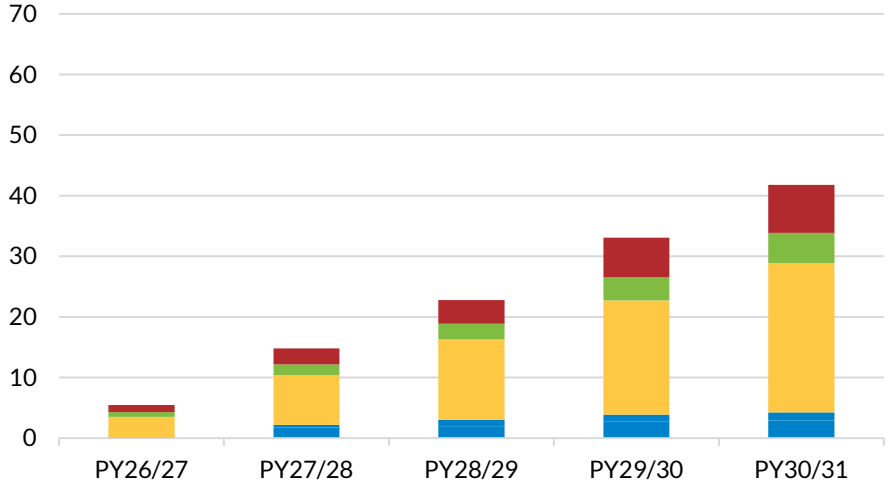
Coal | Gas | Combined Cycle | Dual Fuel Oil/Gas | Nuclear
Oil | Biomass | Pumped Storage | Reservoir Hydro | Run-of-River Hydro
Solar | Wind | Storage

ICAP: *Installed Capacity*
All values are cumulative, and are based on projected nameplate installation for each fuel type

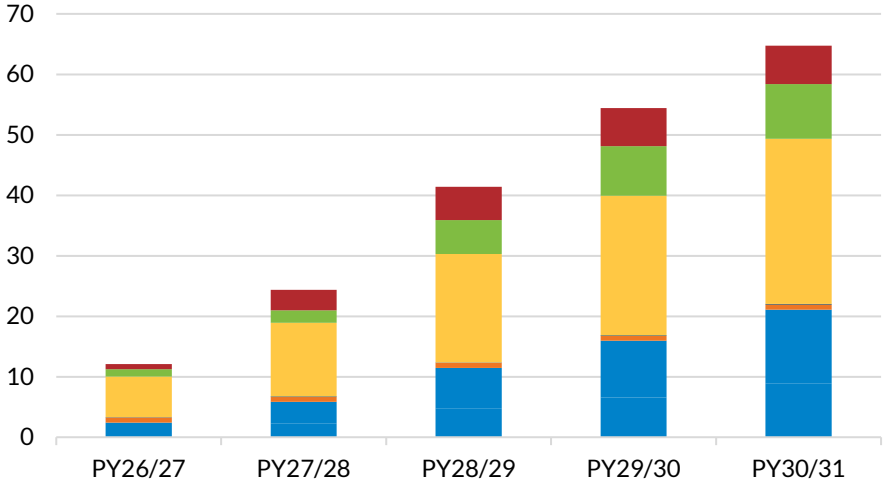
OMS-MISO Survey projections of new resource deliverable nameplate

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

Historical + Replacement Projection
New Resource Nameplate (GW)



Emerging + Replacement Projection
New Resource Nameplate (GW)

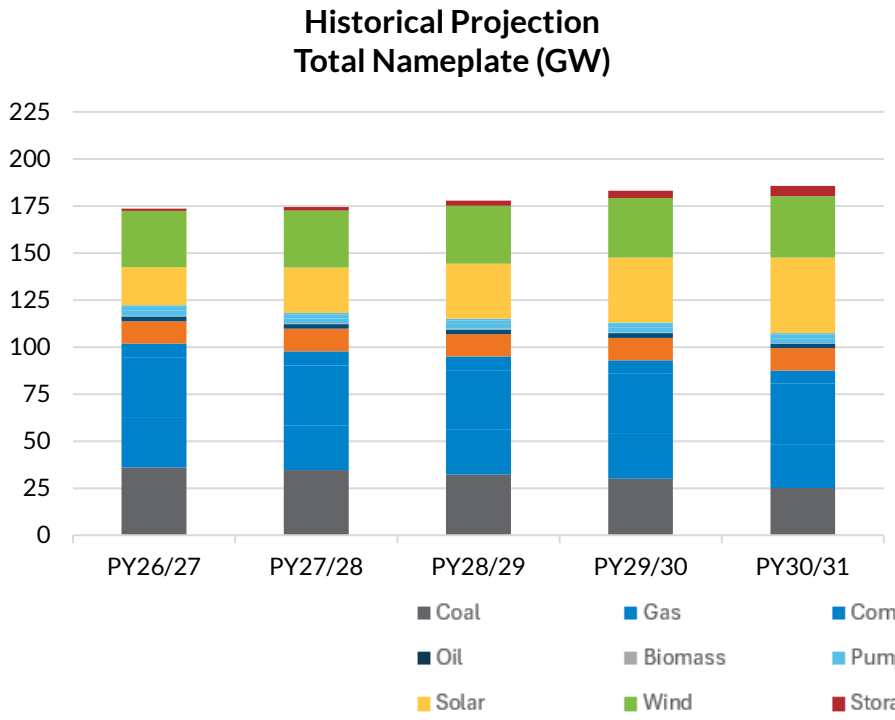


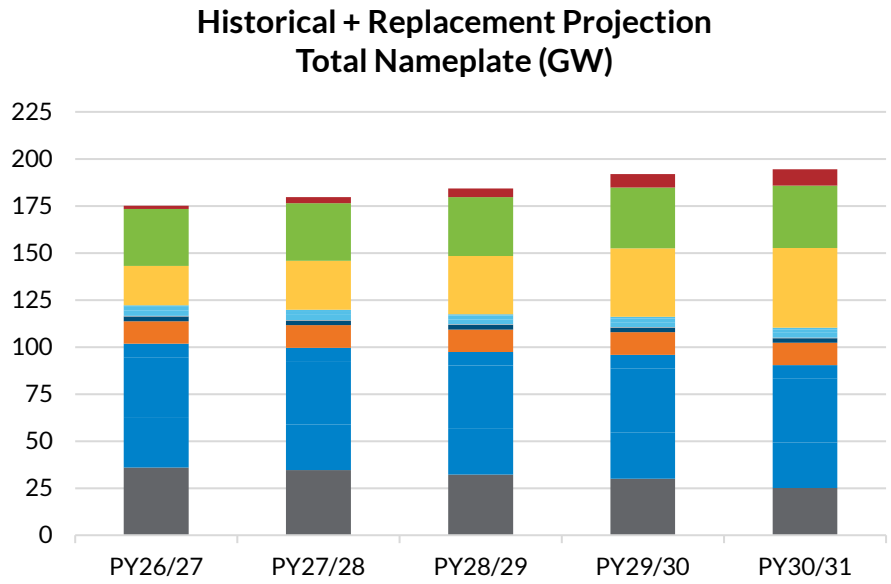
Coal | Gas | Combined Cycle | Dual Fuel Oil/Gas | Nuclear
Oil | Biomass | Pumped Storage | Reservoir Hydro | Run-of-River Hydro
Solar | Wind | Storage

ICAP: *Installed Capacity*
All values are cumulative, and are based on projected nameplate installation for each fuel type

OMS-MISO Survey projections of fleet total deliverable nameplate

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

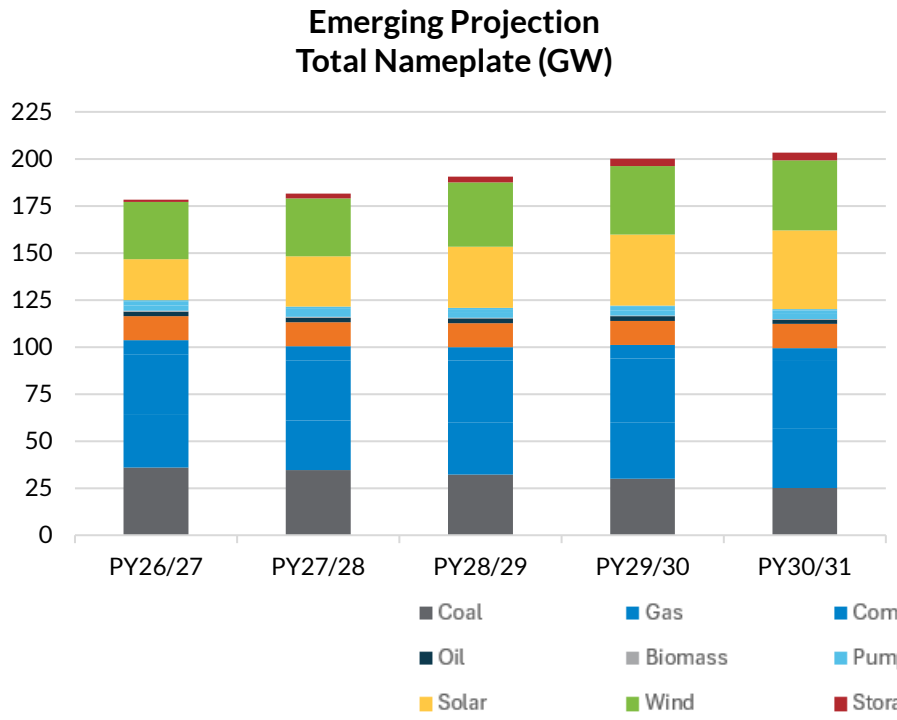


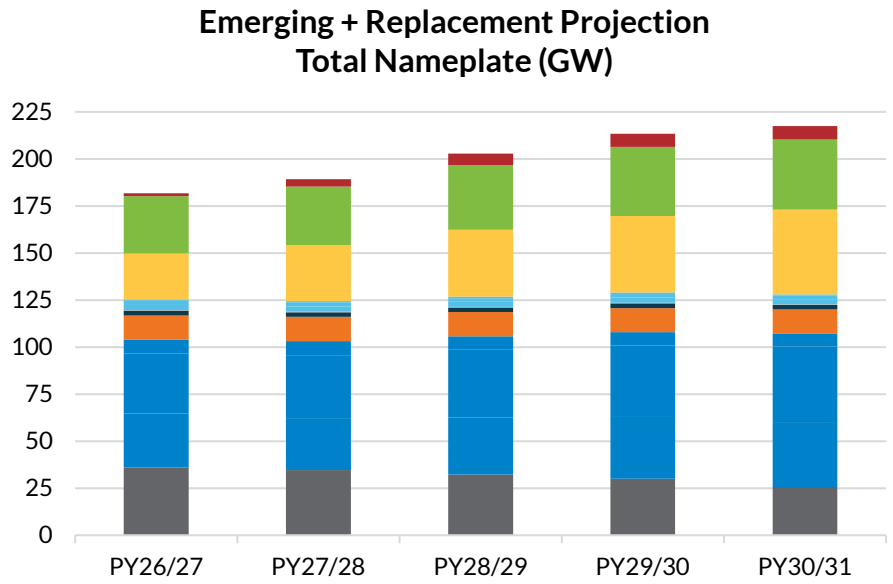


ICAP: *Installed Capacity*

OMS-MISO Survey projections of fleet total deliverable nameplate

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





ICAP: *Installed Capacity*

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-7

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

Filed September 5, 2025

Exhibit 90

MISO ERAS Transmittal Letter

Sarah Nieman
Associate Corporate Counsel
Direct Dial: 317-549-0041
Email: sanieman@misoenergy.org

June 6, 2025

VIA ELECTRONIC FILING

The Honorable Debbie-Anne A. Reese
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: Midcontinent Independent System Operator, Inc.
Revisions to the Open Access Transmission, Energy and Operating Reserve Tariff
Expedited Resource Addition Study Filing
Docket No. ER25-____-000

Dear Secretary Reese:

The Midcontinent Independent System Operator, Inc. ("MISO") submits this filing[1] to revise its Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff")[2] to amend its Attachment X, Generator Interconnection Procedures ("GIP").[3] MISO is grateful for the Commission's feedback on its previous ERAS proposal and for identifying the concerns it had with MISO's proposal.[4] MISO has taken this feedback and refined its original ERAS proposal to address these concerns and others that were shared by stakeholders. MISO now proposes a refined Expedited Resource Addition Study ("ERAS") process that addresses the concerns identified by the Commission and provides an improved framework for the accelerated study of generation projects that can address urgent resource adequacy and reliability needs in the near term.

This filing includes the authority and applicable procedures to implement the refined ERAS process, including how Interconnection Customers claim a new Interconnection Request will meet

[1] MISO makes this filing pursuant to Section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d, and Part 35 of the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"), 18 C.F.R. § 35.1, *et seq*.

[2] All capitalized terms not otherwise defined herein shall have the meaning as set forth in the Tariff or the proposed revisions, as applicable.

[3] The GIP are set forth in Attachment X of the Tariff.

[4] *See Midcontinent Independent System Operator, Inc.*, 191 FERC ¶ 61,131 at P 203 (2025) ("ERAS Order").

a resource adequacy and/or reliability need and how the Relevant Electric Retail Regulatory Authority ("RERRA")[5] will submit a verification to MISO that states either: (i) the new, incremental load addition claimed by the Interconnection Customer is valid and not otherwise included in a resource plan or other process under the RERRA's purview or (ii) that the Generating Facility will address a resource adequacy deficiency. As the Commission recognized in the ERAS Order, "it is appropriate for RERRAs to communicate to MISO their resource adequacy and reliability needs, as well as their support for including interconnection requests in the ERAS process, to ensure that the RERRA's needs are met in a timely fashion."[6] Moreover, the Federal Power Act ("FPA") and FERC precedent both recognize the exclusive authority of state regulators and their jurisdictional utilities to plan for adequate generation resources to address resource adequacy needs within their jurisdictional footprints.[7] ERAS responds to this authority and current needs. It enables the timely development of generation that must be online in the near term to address claimed resource adequacy and/or reliability needs—needs for which the current processing time of MISO's queue presents a barrier to solution availability.

ERAS also complements the recent submittals implementing a proposed cap in the queue as well as other improvements to the GIP including increased milestone payments, withdrawal penalty requirements, and Site Control rules.[8] The Cap and GIP Improvement proposals were focused on longer-term improvements to the queue, while ERAS is focused on short-term improvements that will facilitate the addition of necessary resources in the MISO footprint. MISO has made refinements to its original ERAS proposal to include a total project cap and to structure this cap in a way that accommodates the needs of retail choice states and independent power producers ("IPPs"). MISO has also added several requirements to promote a tighter connection between proposed ERAS projects and the resource adequacy needs that the projects will address. The supporting evidence convincingly demonstrates that the refined ERAS process will provide the expedited path forward to bring projects online to meet near-term needs and will address certain challenges posed by the rapidly growing size of the queue.[9]

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5 A RERRA is defined as "[a]n entity that has jurisdiction over and establishes prices and/or policies for providers of retail electric service to end-customers, such as the city council for a municipal utility, the governing board of a cooperative utility, the state public utility commission or any other such entity." MISO, FERC Electric Tariff, Module A, § 1.R (72.0.0).

6 ERAS Order at P 203.

7 16 U.S.C. § 824 (1976); FERC has recognized that state-federal "bifurcated framework respects the jurisdictional boundaries of the FPA while recognizing the states' historical role in ensuring resource adequacy." *Cxa La Paloma, LLC*, 165 FERC ¶ 61,148 at P 70 (2018).

8 *See Midcontinent Independent System Operator, Inc.*, 186 FERC ¶ 61,054 (2024); *Midcontinent Independent System Operator, Inc.*, "Revisions to the Open Access Transmission, Energy and Operating Reserve Tariff Queue Cap Proposal and Exemptions to the Queue Cap Proposal," Docket No. ER25-507-000 (November 21, 2024).

9 *See* Prepared Direct Testimony of Andrew Witmeier ("Witmeier Testimony"), attached at Tab C.

MISO requests an effective date of August 6, 2025, for this filing. Moreover, given this filing is built on a proposal already reviewed extensively by stakeholders and the Commission and is tailored to address the Commission's guidance, MISO requests the Commission issue an order on this filing expeditiously by July 22, 2025. The grant of this request, in light of the totality of the factors, is reasonable. It will also be limited to the instant request here to effectuate a needed process. Given the resource adequacy and reliability needs identified below, MISO needs to implement that process as soon as possible. An expedited order will afford Interconnection Customers the certainty needed to prepare their Interconnection Requests to submit for the first ERAS Quarterly Study Period, which starts on September 2, 2025. The additional two weeks will provide material value to Interconnection Customers. Additionally, to enable the Commission's expedited decision making, MISO requests that the Commission establish a ten-day comment period for this filing, with June 16, 2025, as the comment date.

MISO acknowledges the expedited action requested places pressure on stakeholders and the Commission alike. This expedited treatment will ensure that Interconnection Customers have sufficient time to prepare for ERAS and have certainty that the proposed changes can be implemented to bring the ERAS process into alignment with other standard MISO practices and processes and to ensure that it will be in place prior to the September 2, 2025 Quarterly Study Period kickoff date for ERAS.[10] Just as this filing has been turned in a matter of a few weeks since receiving the Commission's guidance in the ERAS Order, the time afforded to MISO and Interconnection Customers by two weeks, assuming Commission acceptance, is time well spent to move this proposed process forward effectively. The requested order and effective dates will ensure that the proposed changes are implemented to accelerate the study of projects to address the looming resource adequacy and reliability needs in the MISO footprint in the next few years.

I. EXECUTIVE SUMMARY

A. Summary of MISO's First ERAS Filing

On March 17, 2025, MISO submitted its original filing with proposed revisions to Attachment X in the MISO Tariff, to establish the Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term.[11] MISO proposed that an ERAS Interconnection Request be required to demonstrate that it would meet an identified resource adequacy and/or reliability need by providing both: (1) a written notification from the RERRA that

[10] Witmeier Testimony at 7:6-10.

[11] *Midcontinent Independent System Operator, Inc.*, "Revisions to the Open Access Transmission, Energy and Operating Reserve Tariff Expedited Resource Addition Study Filing," Docket No. ER25-1674-000 (March 17, 2025) ("ERAS Transmittal Letter").

the project should be studied through ERAS; and (2) an executed agreement evidencing that the ERAS project was intended to be used by the entity with the claimed resource adequacy or reliability need. MISO also proposed that ERAS have strict eligibility requirements including: shorter commercial operation date (COD) requirements, greater (100%) site control requirements, higher application fee and milestone payments, and a requirement to pay for all network upgrades documented in the EGIA, even if the Interconnection Customer withdraws its request after the EGIA is executed or filed unexecuted with the Commission. Finally, MISO proposed that the original ERAS process would sunset by the end of 2028.

On May 16, the Commission issued an order rejecting MISO's proposed Tariff revisions and provided guidance on the proposed ERAS process.[12] The Commission found that MISO's ERAS proposal was not "a just and reasonable and not unduly discriminatory or preferential approach for addressing MISO's stated resource adequacy and reliability needs."[13] The Commission identified two issues with the ERAS framework: (1) that there was "no limit on the number of projects that could be entered into the ERAS process,"[14] and (2) "the proposal does not sufficiently describe how the ERAS process is sufficiently targeted to study only interconnection requests needed to meet the anticipated shortfall in generating capacity described by MISO."[15] The Commission also recognized that it was "appropriate for RERRAs to communicate to MISO their resource adequacy and reliability needs, as well as their support for including interconnection requests in the ERAS process, to ensure that the RERRA's needs are met in a timely fashion."[16] Each of the Commissioners also filed individual statements urging MISO to revise and refile its ERAS proposal.[17]

MISO is grateful for the Commission's guidance on how to better craft its ERAS proposal and appreciates the recommendations made within the order. MISO has worked swiftly to develop a refined ERAS process tailored to address the Commission's concerns, other issues raised by stakeholders, and one that can withstand legal review. MISO is now proposing a refined ERAS process that can be implemented by September 2, 2025 to quickly address the looming resource adequacy and reliability needs that it highlighted in its original ERAS filing.

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12 ERAS Order at P 1.

13 *Id.* at P 197.

14 *Id.* at P 199.

15 *Id.* at P 201.

16 *Id.* at P 203.

17 ERAS Order at P 3 (Comm'r Christie, dissenting);at P 6 (Comm'r Rosner, concurring); and at P 8 (Comm'r See, concurring).

B. Growing Resource Adequacy Concerns

The energy industry continues to change rapidly. Urgent resource adequacy and reliability challenges are arising because of continued electrification efforts, a resurgence in manufacturing, an unexpected demand for energy-hungry data centers to support artificial intelligence, the growing preference for low or no carbon emission resources, and the accelerated early retirement of generation.[18] These combined factors are driving resource adequacy and reliability concerns across the country and are resulting in a complex policy landscape. Additional changes and improvements must be made to MISO's processes to enable it to meet these urgent and important needs.

Several surveys and forecasts offer perspectives demonstrating the urgency for MISO to address significant resource adequacy needs in its footprint that are compounded by the addition of unexpected large spot loads. First, MISO's Reliability Imperative Report explained, "[i]n 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."[19]

MISO also works with the Organization of MISO States ("OMS") to produce the OMS-MISO Survey which in 2024 "reinforce[d] near-term risks and highlights key uncertainties impacting resource adequacy in the MISO region," and also "illustrate[d] a strong sensitivity to the pace of new capacity additions."[20] The 2025 OMS-MISO Survey will be published on the same day as this filing and further "reinforces near-term risks and highlights key uncertainties impacting resource adequacy."[21] In fact, one of the key takeaways from the 2025 survey is that

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[18] MISO recently highlighted how "[t]he expansion of data centers, fueled by AI and cloud-based applications, will raise MISO's energy demand by 149-241 TWh by 2044", "the growth of EVs, driven by federal incentives and declining battery costs, is projected to add 54-91 TWh of demand by 2044, with rapid adoption between 2030-2040", "the electrification of oil and gas industries and reshoring efforts are expected to increase energy demand by 21-105 TWh by 2044", and how "federal and state policies are driving electrification of heating systems and appliances, increasing energy demand by 36-43 TWh by 2044." Long-Term Load Forecast, at 4, December 2024, available at:https://cdn.misoenergy.org/MISO%20Long-Term%20Load%20Forecast%20Whitepaper_December%202024667166.pdf.

[19] *See MISO's Response to the Reliability Imperative* (updated January 2023), available at: https://cdn.misoenergy.org/MISO%20Response%20to%20the%20Reliability%20Imperative504018.pdf.

[20] *See 2024 OMS-MISO Survey Results* (Updated June 2024), available at: https://cdn.misoenergy.org/OMS%20MISO%20Survey%20Results%20Workshop%20Presentation628355.pdf.

[21] *Id.* at 2.

"[r]esource adequacy risk is intensifying."[22] Similarly, NERC's 2024 Long-Term Reliability Assessment projected that MISO will experience a 4.7 GW shortfall by 2028 if the current expected generator retirements occur.[23] NERC explained that MISO's resource additions were not keeping up with generator retirements and demand growth. As a result, NERC designated MISO's footprint as "high risk" for falling below established resource adequacy criteria in the next five years.[24] Collectively, these surveys and forecasts demonstrate that MISO *must* address resource adequacy and reliability needs in the next five years and that an accelerated interconnection study process must be established to address time-critical challenges. Compounding these generation challenges is the surge in load growth described above coming from economic development, a resurgence in manufacturing, increasing electrification, and data centers and other large load additions. As the Commission Staff's 2025 Summer Assessment stated: "Currently, the size and speed with which data centers and crypto mining facilities can be constructed and connect to the grid presents unique challenges for demand forecasting and planning. This increase in demand is currently challenging utilities to accelerate infrastructure upgrades and energy resource deployment and to reconsider scheduled resource retirements to maintain grid reliability."[25] As highlighted in MISO's presentation to the System Planning Committee of the MISO Board of Directors, MISO is indeed seeing a significant increase in load growth as well as transmission projects related to load growth over the last year, further evidencing growing demand and challenges in the MISO region.[26] Finally, FERC staff's recent 2025 Summer Assessment found possible reliability challenges in several RTO regions including MISO during extreme summer conditions.[27]

C. Summary of the ERAS Process

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[22] *2025 OMS-MISO Resource Adequacy Survey Results*, Fact Sheet, available at: https://cdn.misoenergy.org/2025%20OMS-MISO%20Survey%20Fact%20Sheet702641.pdf.

[23] *See NERC's 2024 Long-Term Reliability Assessment* (published December 2024), available at: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

[24] *Id.* at 6.

[25] *2025 Summer Energy Market and Electric Reliability Assessment*, May 15, 2025, https://www.ferc.gov/news-events/news/ferc-releases-2025-summer-assessment.

[26] *Reliability Imperative: Transmission Evolution*, System Planning Committee of the Board of Director at 6-7, June 10, 2025, https://cdn.misoenergy.org/20250610%20System%20Planning%20Committee%20of%20the%20BOD%20Item%2005%20Reliability%20Imperative_Transmission%20Evolution701586.pdf.

[27] *2025 Summer Energy Market and Electric Reliability Assessment*, May 15, 2025, https://www.ferc.gov/news-events/news/ferc-releases-2025-summer-assessment.

While developing the original ERAS, MISO engaged with stakeholders on a regular basis to solicit feedback and to discuss suggested changes to the proposal. As described in more detail below, MISO participated in numerous meetings with stakeholders including official committee meetings, ERAS-specific workshops, and small-group meetings with individual stakeholder groups. Based on stakeholder feedback obtained from these meetings and discussions, MISO made significant revisions to its first ERAS proposal presented to stakeholders including changing the mechanics of how a RERRA would notify MISO that a project is suitable for ERAS, establishing the sunset date, and determining some of the eligibility requirements for ERAS participation. OMS provided significant input on the appropriate method for states or RERRAs to notify MISO of projects suitable for MISO's first ERAS proposal. That engagement and feedback helped MISO produce its original ERAS filing to the Commission in March of this year. Following the Commission's order, MISO developed a proposed method for RERRAs to establish a connection between a proposed ERAS project and a resource adequacy deficiency or a spot load addition to address the Commission's guidance and shared its proposed method with individual states and OMS. MISO directly engaged in discussions to address any concerns and this resulting filing is responsive to these conversations and represents a significant step forward towards improving the interconnection process in MISO and enabling it to meet state and RERRA needs. MISO has developed this refiling on an expedited basis and MISO has shared updates with our states to keep them informed of MISO's direction as it finalized the refinements to the original ERAS proposal. While states recognized that a full review of the filing will be required to indicate their support, MISO believes many are generally supportive of the framework and recognize the urgency of having an expedited review process in place.

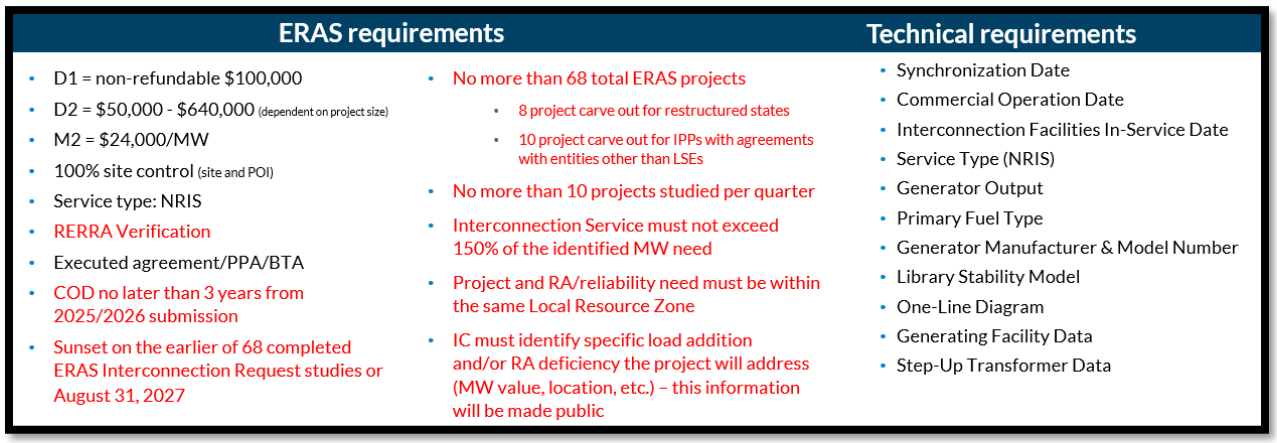
In preparing this filing and refining the ERAS process as described further below, MISO took substantive steps to mitigate the impact of these proposed changes on Interconnection Requests in the queue. MISO remains committed to reducing its general interconnection review period to one year and is utilizing industry-leading techniques, processes, and IT systems to achieve that goal. MISO's recent GIP Improvement and Cap filings were implemented to facilitate this process, but reaping the benefits of those changes will take longer than is necessary to address the looming resource adequacy and reliability needs faced by the states now. ERAS is a unique process that will enable a limited and now capped number of projects to address resource adequacy and reliability needs in the short term. The ERAS process remains structured to insulate projects in the queue from the negative impacts or cost shifts as the result of projects either entering ERAS or leaving the generator interconnection queue for ERAS. As such, the consideration of ERAS projects will not raise costs for or otherwise impact any of the projects currently in the queue.

D. Changes and Refinements to the ERAS Process

The refined Expedited Resource Addition Study ("ERAS") is MISO's answer to addressing the resource adequacy and reliability needs in the near-term. ERAS is a unique process which recognizes that the responsibility for providing grid reliability and resource adequacy in the MISO region is shared by Load Serving Entities ("LSEs"), the states, and MISO. Projects that enter ERAS—a process separate from the standard Generator Interconnection Queue—will be studied

serially in each ERAS quarterly study period and will be granted an EGIA within 90 days to facilitate new generation to come online in the short-term to meet valid new, incremental load additions and identified resource adequacy deficiencies. Since the original ERAS filing, MISO has worked to implement necessary changes to the proposal to better align the process with the timeline that is needed to address the looming resource adequacy and/or reliability needs. First, MISO is now proposing to implement a cap on the number of projects that can participate in ERAS. Second, MISO is requiring a stronger demonstration of a connection between the proposed project and the resource adequacy and/or reliability need that warrants its inclusion in ERAS as demonstrated by a verification from the relevant RERRA. The proposed ERAS project and the resource adequacy and/or reliability need must also be within the same Local Resource Zone. Finally, MISO is also proposing Tariff language to incorporate the retail choice states – Illinois and parts of Michigan – into the ERAS process.[28] MISO's goal with developing and refining ERAS is to quickly, efficiently, and effectively craft a process that can manage these looming needs while also addressing concerns raised in the Commission's order. The figure below highlights in red font what features of the original ERAS filing have been refined and added to this proposal.

Figure 1: Refined ERAS Requirements Comparison



Working together, MISO, the states, and other stakeholders established numerous guardrails around projects that could participate in the original ERAS to ensure that the process is used as intended, that only truly necessary and certain projects can enter ERAS, and to mitigate any impact on projects currently in the general interconnection queue. These guardrails continue to include stringent eligibility requirements such as demonstrating 100% site control for the Interconnection Customer's Interconnection Facilities, establishing a three year due date for Commercial Operation Dates ("COD") based on submission date, requiring a non-refundable deposit of $100,000, a $24,000/MW milestone payment, all of which are due upon application, and agreeing to paying for all necessary Network Upgrades per the executed GIA. MISO is also

[28] *See* Tab A Redlines, Attachment X, Section 3.9.1.1(iii).

proposing several changes to the Interconnection Request application to ensure that the necessary information is supplied by the Interconnection Customer when applying to participate in ERAS.

The refined ERAS framework continues to incorporate the role of states and RERRAs but requires a written verification from the RERRA that the proposed project will address a load addition not already planned for or an identified resource adequacy deficiency within its jurisdictional footprint. The Commission has previously recognized that "MISO's resource adequacy construct is designed specifically to complement state mechanisms."[29] MISO continues to support "the independent authority of state regulators for resource adequacy and facilitates resource adequacy goals with state regulators that have decision-making authority over the amount and types of resources that are necessary to meet shared objectives."[30] The ERAS process still provides a vehicle for the RERRA to verify to MISO that there is a valid, new incremental load addition that is not incorporated in relevant plans or that the proposed Generating Facility will address an identified resource adequacy deficiency. While this verification is not *confirmation* by the state/RERRA of a project's approval,[31] and should not be viewed as such, it does directly connect the proposed ERAS project with a specific load need. This, along with the requirement that the load need and the ERAS project must be located in the same LRZ region, better tailors the ERAS process to the resource adequacy and reliability needs.

This refined ERAS proposal also is in alignment with the open access principles establish by the Commission and consistent with the goals of Order Nos. 2003[32] and 2023.[33] Given the dramatic changes the electric industry is undergoing and the increasing demand for electricity expected in the MISO footprint, there is great urgency to establish a process that enables "shovel ready" projects addressing near term resource adequacy and/or reliability needs to be completed

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29 *Midcontinent Indep. Sys. Operator, Inc.*, 170 FERC ¶ 61,215 at P 118 (2020) (citing MISO, FERC Electric Tariff, Module E-1, § 68A (34.0.0). MISO's Module E-1 mandatory requirements for Market Participants serving Load "recognize and are complementary to the reliability mechanisms of the states" and nothing in Module E-1 "affects existing state jurisdiction over the construction of additional capacity or the authority of the states to set and enforce compliance with standards for adequacy."

30 *Id.*

31 As will be further explained Section III.A.2, *infra*, even if a project participates in the ERAS process, regulatory review and approval of the project by the state/RERRA is still required.

32 *See Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, FERC Stats. & Regs. ¶ 31,146 (2003), *order on reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, *order on reh'g*, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007), cert. denied, 552 U.S. 1230 (2008).

33 *See Improvements to Generator Interconnection Procs. & Agreements*, Order No. 2023, 184 FERC ¶ 61,054, *order on reh'g*, 185 FERC ¶ 61,063 (2023), *order on reh'g*, Order No. 2023-A, 186 FERC ¶ 61,199, *errata notice*, 188 FERC ¶ 61,134 (2024).

in a short period of time. As revised to address Commission guidance, ERAS provides that capability and will facilitate the quick completion of projects necessary to address resource adequacy and/or reliability needs in the next few years. The package presented in this filing is just and reasonable and supported by testimony and other evidence, and the Commission should approve it promptly to ensure that MISO can initiate the ERAS process as expeditiously as possible.

II. DEVELOPING THE ERAS PROCESS

A. Overview of MISO'S Generator Interconnection Process

In an effort to constantly improve its generator interconnection process, MISO implemented significant changes to the process over the last two years. First, in 2023, MISO submitted a proposal to make certain improvements to the interconnection process, which involved increasing milestone payments, establishing withdrawal penalty requirements, and implementing certain Site Control rules.[34] Second, in 2024, MISO submitted its Queue Cap Proposal, which established a cap on the total MW value of Interconnection Requests entering a given study cluster.[35] These changes to the queue were made primarily to address the unprecedented challenges MISO faced when evaluating the feasibility and certainty of a large number of projects proposing to connect to the MISO Transmission System. These proposals were necessary to address both the quality and quantity of interconnection requests – thus they were aimed at reducing speculative projects in the queue, making the current queue process more efficient, and reducing the causes of delay.

MISO's first cap proposal, submitted in 2023, included an exemption to the cap for any interconnection requests involving a proposed generation facility that was submitted by a RERRA.[36] The RERRA exemption was proposed in recognition that some proposed Generating Facilities may be required by one or more MISO States or other jurisdictional entities to meet their load serving obligations. As MISO explained in its filing, "[p]roviding this exemption is consistent with the cooperative federalism principles underlying the FPA and placing the primary responsibility over resource adequacy on state regulators."[37] Moreover, the Organization of MISO

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[34] *See Midcontinent Indep. Sys. Operator, Inc.*, Docket No. ER24-340-000, MISO's Transmittal Letter (filed Nov. 3, 2023) ("Queue Reform Filing").

[35] *See Midcontinent Indep. Sys. Operator, Inc.*, Docket No. ER25-507-000, MISO's Transmittal Letter (filed Nov. 21, 2024) ("2024 Cap Filing, Transmittal Letter").

[36] *See Midcontinent Indep. Sys. Operator, Inc.*, Docket No. ER24-341-000, MISO's Transmittal Letter (filed Nov. 3, 2023) ("2023 Cap Filing, Transmittal Letter").

[37] 2023 Cap Filing, Transmittal Letter at 16.

States ("OMS") supported the exemption and proposed a procedure for a RERRA to request that an Interconnection Request associated with a project be exempt from the cap.[38] Ultimately, FERC denied MISO's request to approve the 2023 Queue Cap Proposal with the RERRA exemption.[39]

MISO's second Cap Proposal, submitted in 2024, did not include the RERRA exemption. In the testimony, MISO explained that in lieu of the exemption, it would be proposing the ERAS process to "expedite the approval of new generation needed to address state resource adequacy goals."[40] MISO recognized that the RERRA exemption was attempting to address a distinct queue issue that warranted its own proposal to facilitate the approval process of new generation needed to address resource adequacy.[41] In the 2024 Cap Proposal, MISO committed to working on addressing the needs of RERRAs through a new process that would be developed with stakeholders and that would more comprehensively conduct the process for new generation that was addressing resource adequacy and reliability needs.[42]

MISO's original ERAS proposal, submitted in March of 2025, aimed at addressing short-term resource adequacy and reliability needs.[43] The previously proposed ERAS process required enhanced commitments from the Interconnection Customer including 100% Site Control and full commitment to pay for all the costs of identified Network Upgrades per the executed EGIA even if the project is later withdrawn and the EGIA terminated.[44] MISO also required ERAS projects to have written notification from a RERRA indicating that it should be studied in the ERAS process. MISO originally planned to offer 14 cycles of ERAS studies prior to its sunset in 2028. In May 2025, the Commission issued an order rejecting MISO's proposal and identified two main problems with the initial ERAS filing: 1) there was no limitation on the number of projects that could participate; and 2) the RERRA notification was insufficient to establish a connection between the proposed project and the identified resource adequacy and/or reliability need. The Order also included helpful guidance for MISO to follow when refining its proposal.[45]

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38 *See Midcontinent Indep. Sys. Operator, Inc.*, Docket No. ER24-341-000, Comments of Organization MISO States ("OMS") in support of Midcontinent Independent System Operator, Inc.'s November 3, 2023 (filed Dec. 4, 2023).

39 *See Midcontinent Indep. Sys. Operator, Inc.*, 186 FERC ¶ 61,054 (2024), *order on reh'g*, 187 FERC ¶ 61,031.

40 2024 Cap Filing, Tab C: Prepared Direct Testimony of Andrew Witmeier at 5:2-3.

41 *See id.* at 29:10-21.

42 *Id.* at 30:2-7.

43 *Midcontinent Independent System Operator, Inc.*, "Revisions to the Open Access Transmission, Energy and Operating Reserve Tariff Expedited Resource Addition Study Filing," Docket No. ER25-1674-000 (March 17, 2025) ("ERAS Transmittal Letter").

44 ERAS Original Filing, Witmeier Testimony at 41:4 –11.

45 ERAS Order at P 199.

Following this feedback, MISO has made several refinements to its original ERAS proposal. First, MISO is now capping the number of projects that can participate in ERAS to 68 projects total—with a carve out of 8 projects that may only be submitted by retail states for resource adequacy deficiencies and 10 projects that may only be submitted by independent power producers ("IPPs").[46] In addition, MISO is capping the number of projects that can participate in each ERAS Quarterly Study Period to 10 projects no matter if they are proposed by retail states, IPPs, or other applicants.[47] MISO also changed the RERRA requirement to include a verification instead of a notification to better establish a nexus between the proposed ERAS project and the identified resource adequacy and/reliability need. MISO is now requiring that the ERAS project be within the same LRZ as the load it is addressing unless the project applicant can demonstrate that the use of a Generating Facility not in the same LRZ was included in a resource filing or other submission made to the relevant RERRA.[48] A project applicant for ERAS must now supply three documents: 1) the RERRA verification; 2) the off-taker agreement; and 3) the Interconnection Request for ERAS that contains additional information requirements. MISO believes that this documentation will serve to demonstrate that the proposed ERAS project is targeted at serving a specific resource adequacy deficiency and/or reliability need and will serve to identify the parties involved in the agreement. The refined ERAS process will only be offered until August 31, 2027, or when 68 ERAS Interconnection Request studies have been completed, whichever comes first.[49] And all ERAS projects must be completed and commercially operable three years after their submission date.[50]

ERAS is MISO's short-term solution to the resource adequacy and reliability problems that it is facing in its footprint. The revised proposal filed herein is temporary but critically necessary as a bridge to ensure time-sensitive new resource adequacy needs will be met while MISO works with its stakeholders to reduce the processing time of its queue by 2028. By necessity, the process is flexible enough to be utilized by all RERRAs in MISO's footprint that need such a tool and by any type of Interconnection Customer with a qualifying project. The stringent entry requirements, the newly instituted project cap, the modified RERRA verification, the additional application requirements, and robust process safeguards make ERAS a process that is flexible enough while

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[46] Witmeier Testimony at 4:3-9.

[47] *Id.* at 4:5-6, 17:3-5, 27:8-15.

[48] *Id.* at 4:6-15.

[49] Witmeier Testimony at 49:6-15. This time limitation also applies to the retail state projects. If the retail states do not submit their allotted eight projects by the sunset date, the ERAS process will still close on August 31, 2027.

[50] Witmeier Testimony at 47:14-17. One exception to this rule is if the project has been deferred to a future ERAS quarterly study cycle.

remaining narrowly scoped and appropriately bounded to prevent misuse or negative impacts for projects in the MISO queue.

B. Imminent Resource Adequacy and Reliability Concerns

Like the other RTOs and ISOs, MISO's resource adequacy concerns are driven by unexpected but significant load growth associated with large data center development, the accelerated retirement of baseload generation due to state and federal policies, a resurgence of manufacturing, and delays in the generator interconnection queue caused by speculative projects, late-stage dropouts, supply chain delays, and permitting or financing issues. What is unique to MISO as compared to other RTOs and ISOs is that it is almost completely comprised of vertically integrated utilities who are responsible for serving load within their jurisdictions. The LSEs are accountable for supplying their customers with consistent power and must ensure that they can address resource adequacy needs in a time-sensitive manner. Thus, MISO must partner *with* the states and their RERRAs and LSEs to provide a way for projects that have been identified as necessary for resource adequacy or reliability needs to be completed quickly. MISO's outlook on resource adequacy within its footprint is supported by several studies that are completed on a regular basis. As these studies demonstrate, the load growth outlook has changed dramatically in the past few years due to unforeseen changes in the electricity industry.

First, MISO's Reliability Imperative Report found that the transition towards decarbonization is "posing material, adverse challenges to electric reliability."[51] The Report recognized that major industry trends are "simultaneously changing the conditions of the system" and that demand for electricity is increasing to meet new needs, which is disrupting traditional load patterns.[52] MISO noted that over the last decade, surplus reserve margins in MISO have been exhausted through load growth and unit retirements.[53] "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."[54] MISO also published the MISO Futures Report, which provides the analysis of three scenarios to help MISO envision a set of possible resource adequacy outcomes up to 20 years in the future. The scenarios establish a range of economic, policy, and technological possibilities including load growth, electrification, decarbonization, renewable energy levels,

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[51] *See MISO's Response to the Reliability Imperative,* Executive Summary (updated February 2024) at 1, https://cdn.misoenergy.org/Executive%20Summary%202024%20Reliability%20Imperative%20report%20Feb.%2021%20Final631825.pdf.

[52] *Attributes Roadmap, A Reliability Imperative Report* (December 2023) at 6, https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf.

[53] *See MISO's Response to the Reliability Imperative,* (updated February 2024) at 6, ("Reliability Imperative"), https://cdn.misoenergy.org/2024%20Reliability%20Imperative%20report%20Feb.%2021%20Final504018.pdf?v=20240221104216.

[54] *Id.*

generator retirements, fuel prices, and generation capital costs. While MISO originally published the Series 1 analysis in 2022, due to the dramatic changes in the energy industry even in the last couple of years, MISO was required to update the outlook as its "members' and states' plans were refined, new legislation and policies took effect, and prices, along with incentives for various resources, saw significant changes."[55] As a result of these changes, MISO was required to revise the Series 1 Futures earlier than anticipated with updated data "to reflect a significant fleet transition over the next 20 years."[56] Both Futures Reports demonstrated the immediate need to add almost twice the generation that MISO currently has online, and that rate is increasing as a result of the unprecedented load growth.[57]

Second, the annual OMS-MISO Survey indicated similar results in 2024, "reinforc[ing] near-term risks and highlight[ing] key uncertainties impacting resource adequacy in the MISO region."[58] The survey compiles information about new resources that the utilities and states plan to build and about any older assets they intend to retire in the coming years. The 2024 survey finds that "resource adequacy risks could grow over time across all seasons, absent increased new capacity additions and actions to delay capacity retirements."[59] The survey noted that "significant economic development activities are spurring new, large spot-load additions (e.g., data centers, onshoring of manufacturing, new industrials) and increasing pressures on resource adequacy and requiring improved abilities for the timely addition of new resources."[60] EPRI, Grid Strategies, and MISO also anticipate strong long-term load growth that is driven by data centers, manufacturing, increased cooling demands, electric vehicles, and cryptocurrency.[61] Grid Strategies even noted "[o]ver the past year, grid planners nearly doubled the 5-year load growth

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55 *MISO Futures Report Series 1A* (Nov. 1, 2023) at 2, https://cdn.misoenergy.org/Series1A_Futures_Report630735.pdf.

56 *Id.*

57 *Id.* at 6-8; *see also*, *MISO Futures Report* (updated December 2021) at 4, https://cdn.misoenergy.org/MISO%20Futures%20Report538224.pdf.

58 *See 2024 OMS-MISO Survey Results* (June 20, 2024), ("2024 OMS-MISO Survey") at 2, https://cdn.misoenergy.org/OMS%20MISO%20Survey%20Results%20Workshop%20Presentation628355.pdf.

59 *Id.*

60 *Id.*

61 *2024 OMS-MISO Survey* at 12*; see also* EPRI, *Reindustrialization, Decarbonization, and Prospects for Demand Growth* (Jul. 27, 2023), https://www.epri.com/research/products/000000003002027930; John D. Wilson and Zach Zimmerman, Grid Strategies, *The Era of Flat Power Demand is Over* (December 2023), ("Grid Strategies Report"), https://gridstrategiesllc.com/wp-content/uploads/2023/12/National-Load-Growth-Report-2023.pdf.

forecast."[62] The 2024 OMS-MISO survey also noted that "immediate actions are needed to expedite the addition of new capacity, coordinate resources for new load additions, and potentially moderate the pace of resource retirements."[63]

The recently published 2025 OMS-MISO Survey further "reinforces near-term risks and highlights key uncertainties impacting resource adequacy."[64] The 2025 survey shows a range of outcomes but indicates that "[a]t least 3.1 GW of new resources are needed by summer 2026/27 to avoid a resource deficit, with greater needs in future years."[65] The survey responses "show increasing load forecasts year-over-year and are close to the high end of MISO Long-Term Load Forecast."[66] The 2025 survey noted that data centers, electric vehicles, and industry development are anticipated to have a high impact in MISO's footprint.[67] Finally, the 2025 Survey recognized that there is significant uncertainty in projected resource adequacy, underscoring the urgent need for accelerated resource additions, strategic retirement planning and proactive management of increasing load growth. Using both the Regional Resource Assessment ("RRA") and OMS-MISO Survey together provides a unique outlook for resource planners as the RRA is "a 20-year outlook based on publicly announced resource plans and policy goals" while the OMS-MISO Survey is "more focused on the near term and projects new installed capacity coming online at the pace at which resources have received interconnection agreements and come online in recent history."[68]

Third, the 2024 NERC Long-Term Reliability Assessment highlighted the mounting reliability challenges faced by the energy industry caused by accelerating generator retirements, declining dispatchable resources, and escalating demand growth.[69] NERC noted that "[e]lectricity peak demand and energy growth forecasts over the 10-year assessment period continue to climb;

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62 *Grid Strategies Report* at 3.

63 *2024 OMS-MISO Survey* at 16.

64 *See 2025 OMS-MISO Survey Results* at 2.

65 *See 2025 OMS-MISO Resource Adequacy Survey Results*, Fact Sheet, available at: https://cdn.misoenergy.org/2025%20OMS-MISO%20Survey%20Fact%20Sheet702641.pdf.

66 *Id.* at 10.

67 *Id.* at 10.

68 Comments of Todd Ramey on behalf of MISO at 9, Docket No. AD25-7, May 28, 2025 ("MISO RA Tech Conference Comments").

69 *See NERC 2024 Long-Term Reliability Assessment* (December 2024), ("NERC Report") https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

demand growth is now higher than at any point in the past two decades."[70] The assessment found that for 2025-2029, MISO was categorized as high risk for falling below established resource adequacy criteria.[71] The Report determined that resource additions were not keeping up with generator retirements and demand growth in the MISO footprint.[72] "MISO is at a high risk of experiencing electricity supply shortfalls beginning in Summer 2025 based on [prospective reserve margins] derived from anticipated resources and demand forecasts."[73] As part of NERC's assessment of MISO, it explained that "[i]ncreased coordination between MISO and its members will be critical to ensuring reliability throughout this resource transition of integrating new intermittent resources and continuing to retire conventional resources."[74]

More recently, NERC issued its summer reliability assessment for 2025.[75] In its report, NERC noted that "[s]ince last summer, the aggregate of peak electricity demand for NERC's 23 assessment areas has risen by over 10 GW – more than double the year-to-year increase that occurred between the summers of 2023 and 2024."[76] NERC also identified MISO has having resource adequacy or energy risks for the summer and noted elevated "potential for insufficient operating reserves in above-normal conditions."[77] NERC similarly highlighted 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."[78] Finally, in its assessment, NERC noted that "[t]he summer of 2024 was the fourth hottest on record for both the contiguous United States and Canada, with some areas experience their hottest summer ever. The result was record electricity demand in the United States as well as in Canada."[79]

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[70] *Id.* at 8.

[71] *Id.* at 6.

[72] *Id.* at 7.

[73] *Id.* at 13.

[74] *Id.* at 43.

[75] *2025 Summer Reliability Assessment*, North American Electric Reliability Corporation, May 2025, ("NERC 2025 Assessment"), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf.

[76] *Id.* at 5.

[77] *Id.* at 10.

[78] *Id.* at 16.

[79] *Id.* at 50.

Finally, MISO submitted comments prior to FERC's Technical Conference on the challenge of resource adequacy in RTO and ISO regions, which was held on June 4 and 5, 2025.[80] In its comments, MISO noted that "the MISO region faces resource adequacy and reliability challenges due to the changing characteristics of the electric generating fleet, insufficient transmission system infrastructure, growing pressures from extreme weather, and rapid load growth."[81] MISO explained that it is expecting significant growth in wind and solar development: "MISO's Future Planning Scenarios estimate that while the total amount of installed electric generation will increase significantly over the next 20 years due to the rapid growth of wind and solar, the actual amount of electricity available to the system during could face a net decline of about 32 GW due to the operational characteristics of these new resources."[82] MISO also emphasized that "based on the current trajectory, peak electric load in the MISO region is projected to grow at a 1.6% compound annual growth rate ('CAGR'). This compares to an average 0.5% CAGR between 2009 and 2024 and threatens to outpace new electric resource additions if urgent action isn't taken."[83] MISO concluded that "[w]ith the pace of change confronting the electricity system, the impending influx of large data centers and the evolving generation portfolio there is heightened urgency to ensure the system remains reliable."[84] NERC also submitted comments in this docket noting that "growth projections of electric demand have reached heights unseen in decades, disrupting resource adequacy plans across North America."[85]

Collectively, these reports and comments provide a perspective demonstrating that MISO and its members need to act quickly and collaboratively to address resource adequacy and reliability needs in the MISO footprint over the next five years.[86] The original ERAS proposal was developed by MISO in coordination with its stakeholders to address these needs and to enable projects addressing resource adequacy and/or reliability to be brought online quickly. As NERC recognized, "MISO's resource adequacy construct complements the jurisdiction that regulatory authorities have in determining the necessary level of adequacy."[87] The refined ERAS proposal

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80 MISO RA Tech Conference Comments at 1.

81 *Id.*

82 *Id.* at 2.

83 *Id.* at 3.

84 *Id.* at 27.

85 Prefiled Statement of Jim Robb, President and CEO of North American Electric Reliability Corporation at 1, Docket No. AD25-7, May 19, 2025 ("NERC RA Tech Conference Comments").

86 In fact, MISO updated the Futures Report from November 2023 used to study LRTP Tranche 2.1 because load assumptions changed so dramatically over the past year and half.

87 NERC Report at 43.

further enables MISO to work *with* its members to address resource adequacy and reliability needs in the short-term.

C. Development of ERAS and the Stakeholder Process

Between November of 2024 and March of 2025, MISO conducted an extensive stakeholder process, which included discussions, presentations, and numerous opportunities for stakeholder input at the Planning Advisory Committee ("PAC") and also in ERAS-specific workshops. The stakeholder engagement process for MISO's ERAS proposal went as follows:

- November 13, 2024: MISO introduced the need for ERAS at the PAC and requested formal written feedback from stakeholders.[88]

- November 18, 2024: MISO and stakeholders participated in a special ERAS-specific workshop in which the parties continued to discuss ERAS details. MISO sought feedback on the ERAS proposal.[89]

- December 6, 2024: MISO and stakeholders participated in a second ERAS-specific workshop in which the parties continued to discuss ERAS details. MISO sought feedback on the updated proposal.[90]

- January 22, 2025: MISO presented an updated ERAS proposal at the PAC.[91]

- February 19, 2025: MISO posted proposed tariff redlines, presented an updated ERAS proposal, and sought feedback at the PAC.[92]

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88 *See Expedited Resource Adequacy Study (ERAS) Introduction* (November 13, 2024), https://cdn.misoenergy.org/20241113%20PAC%20Item%2009%20Expedited%20Resource%20Adequacy%20Study%20(ERAS)%20Introduction660245.pdf.

89 *See Expedited Resource Adequacy Study (ERAS) Workshop* (November 18, 2024), https://cdn.misoenergy.org/20241118%20Expedited%20Resource%20Adequacy%20Study%20(ERAS)%20Workshop661622.pdf.

90 *See Expedited Resource Adequacy Study (ERAS) Workshop* (December 6, 2024), https://cdn.misoenergy.org/20241206%20Expedited%20Resource%20Adequacy%20Study%20(ERAS)%20Workshop665747.pdf.

91 *See Expedited Resource Addition Study (ERAS) Proposal* (January 22, 2025), https://cdn.misoenergy.org/20250122%20PAC%20Item%2006c%20Expedited%20Resource%20Addition%20Study%20(ERAS)%20Proposal%20(PAC-2023-1).pdf673403.pdf.

92 *See Expedited Resource Addition Study (ERAS) Proposal* (February 19, 2025), https://cdn.misoenergy.org/20250219%20PAC%20Item%2009%20Expedited%20Resource%20Addition%20Study%20(ERAS)%20Proposal%20(PAC-2023-1)679608.pdf.

- March 7, 2025: MISO posted updated proposed tariff redlines and presented the final ERAS proposal at a special PAC meeting scheduled to review the ERAS proposal.[93]

- November 2024 – March 2025: MISO staff engaged in dozens of individual calls with stakeholders to discuss what changes they think should be made to the ERAS proposal.

In addition to these more general stakeholder meetings, OMS provided significant input on the appropriate method for states or RERRAs to notify MISO of projects suitable for ERAS. Collaboration between MISO and OMS on the mechanics of the RERRA notification process and the language added to MISO's Tariff was key. The input from OMS ensures that the ERAS process can be utilized across the footprint even though the regulatory processes differ in each state.

Following the Commission's rejection of MISO's original ERAS filing and the guidance provided in its Order, MISO re-engaged with its stakeholders to develop the refined ERAS proposal as developed in herein. MISO presented its refined ERAS proposal at the May 28, 2025 PAC meeting where MISO presented the disposition of its original ERAS filing in Docket No. ER24-1674.[94] MISO received feedback from stakeholders following the PAC meeting through its informal feedback tool.[95]

D. States Have Authority Over Resource Adequacy

Due to MISO's unique organizational structure consisting of almost exclusively vertically integrated utilities, resource adequacy determinations must be made in collaboration with the states. As MISO recently explained in comments filed with FERC, "[e]very effort in pursuit of the Reliability Imperative is centered around the shared responsibility between MISO-member electricity providers, states, and MISO to maintain a reliable grid."[96] FERC has recognized that state authority over resource adequacy is emphasized more in MISO than in other RTOs.[97] MISO

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93 *See Expedited Resource Addition Study (ERAS) Proposal* (March 7, 2025), https://cdn.misoenergy.org/20250307%20PAC%20Item%2002%20Expedited%20Resource%20Addition%20Study%20(ERAS)%20Proposal%20(PAC-2023-1)684427.pdf.

94 *See Expedited Resource Addition Study (ERAS) Next Steps* (May 28, 2025), https://cdn.misoenergy.org/20250528%20PAC%20Item%2008%20Expedited%20Resource%20Addition%20Study%20(ERAS)%20Next%20Steps%20(PAC-2023-1)699836.pdf.

95 *Informal Feedback (2025)*, MISO, https://www.misoenergy.org/engage/stakeholder-feedback/2025/informal-feedback-2025/.

96 MISO FERC RA Tech Conference Comments at 27.

97 ERAS Order at P 203 ("We recognize that, given their authority, responsibilities, and expert assessment of their resource adequacy needs, it is appropriate for RERRAs to communicate to MISO their resource adequacy and

firmly believes that it should not be selecting ERAS projects that may address resource adequacy or reliability needs, but rather that responsibility is firmly within the states' jurisdiction. In fact, "[s]ince MISO's inception, deference has been made to the jurisdictional authority of the states and other RERRAs with respect to resource adequacy rights and responsibilities that RERRAs take seriously."[98]

The overlap between state and federal authority in the electric industry is governed by the Federal Power Act ("FPA").[99] "The Commission is a creature of statute and has jurisdiction only over those matters that Congress has given it the authority to regulate."[100] To that end, FERC has jurisdiction over regulating interstate "wholesale" electricity sales and transmission markets, whereas the states have jurisdiction over "retail" sales and "over facilities used for the generation of electric energy."[101] Under the FPA, federal and state powers are "complementary" and "like all collaborative federalism statutes, envisions a federal-state relationship marked by interdependence."[102] Thus, determining "resource adequacy raises 'complex jurisdictional concerns' which at times are at the 'confluence of state-federal jurisdiction.'"[103] At this confluence, FERC has recognized that "this bifurcated framework respects the jurisdictional boundaries of the FPA while recognizing the states' historical role in ensuring resource adequacy."[104] FERC has clearly stated that "a workable approach to resource adequacy does not mean that we should ignore the states' traditional role in this area."[105] Thus, "[w]ith the exception of the broad authority of [FERC], over the need for and pricing of electrical power transmitted in interstate commerce … these economic aspects of electrical generation have been regulated for

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reliability needs, as well as their support for including interconnection requests in the ERAS process, to ensure that the RERRA's needs are met in a timely fashion.").

98 MISO FERC RA Tech Conference Comments at 12.

99 16 U.S.C. § 824 (1976).

100 *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,115 at P 66 (2025) ("Co-Location Order") (citing *Atl. City Elec. Co. v. FERC*, 295 F.3d 1, 8 (D.C. Cir. 2002)).

101 16 U.S.C. § 824(b)(1).

102 *Hughes v. Talen Energy Mktg., LLC*, 578 U.S. 150, 167 (2016) (Sotomayor, J., concurring); *see also FERC v. Electric Power Supply Ass'n*, 577 U.S. 260, 289 (2016) ("EPSA").

103 *Plan. Res. Adequacy Assessment Reliability Standard*, 134 FERC ¶ 61,212 at P 20 (2011) (citing *Cal. Indep. Sys. Operator Corp*., 116 FERC ¶ 61,274 at P 1112 (2006), *order on reh'g*, 119 FERC ¶ 61,076 (2007), *order on reh'g* 120 FERC ¶ 61,271 (2007)).

104 *See California Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274 at P 1117 (2006); *Cxa La Paloma, LLC*, 165 FERC ¶ 61,148 at P 70 (2018).

105 *California Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274 at P 1117 (2006).

many years and in great detail by the states."[106] Notably, the states have long relied on the FPA's reservation of state control over their own generation as an unambiguous sanction of states' authority to control their own resource mix.[107] Similarly, FERC has recognized this sanction of authority to the states to control their own resource mix.[108]

The Supreme Court has similarly recognized this jurisdictional overlap and the states' authority in this area. "Alongside those grants of power [under the FPA], however, the Act also limits FERC's regulatory reach, and thereby maintains a zone of exclusive state jurisdiction."[109] "But the law places beyond FERC's power, and leaves to the States alone, the regulation of 'any other sale' – most notably, any retail sale – of electricity."[110] This reserved authority to the states includes control over in-state "facilities used for the generation of electric energy."[111] The Supreme Court explained that the "need for new power facilities" is "characteristically governed by the states."[112] "These matters are consistent with those that the Supreme Court has long held to be within the states' historic police powers, and the Court has observed that the FPA's jurisdictional divide 'was drawn with meticulous regard for the continued exercise of state power, not to handicap or dilute it in any way.'"[113] Finally, the Supreme Court has similarly determined that, under the FPA, the states have authority over their generation resource mix.[114]

This unique jurisdictional overlap affects how MISO collaborates with the 15 states in its footprint in determining resource adequacy needs. Compared to other RTOs and ISOs, resource adequacy is viewed and treated differently in MISO, which runs a voluntary capacity market and

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106 *Pac. Gas & Elec. Co. v. State Energy Res. Conservation & Dev. Comm'n*, 461 U.S. 190, 205–06 (1983).

107 *See Hughes*, 578 U.S. at 166; *EPSA*, 577 U.S. at 266 (explaining that the FPA "limits FERC's regulatory reach, and thereby maintains a zone of exclusive state jurisdiction.").

108 *See California Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274 at P 1118 (2006) ("While we find that resource adequacy is necessary for the reliable operation of the grid, and to ensure that wholesale rates are just, reasonable and not unduly discriminatory, we are not establishing planning reserve requirements, but instead are adopting those set by state and Local Regulatory Authorities in the first instance.").

109 *EPSA*, 577 U.S. at 266.

110 *Id.* at 265 (citing § 824(b)).

111 *Hughes*, 578 U.S. at 154 (quoting § 824(b)(1)).

112 *Id.* (quoting *Pac. Gas & Elec. Co. v. State Energy Res. Conservation & Dev. Comm'n*, 461 U.S. at 205).

113 Co-Location Order, 190 FERC ¶ 61,115 at P 67 (2025) (citing *Munn v. People of State of Ill.*, 94 U.S. 113 (1876) and quoting *Oneok, Inc. v. Learjet, Inc.*, 575 U.S. 373, 384-85 (2015) (discussing the analogous provisions in the Natural Gas Act) (internal citations omitted)).

114 *See, e.g., Citizens Action Coal. of Ind., Inc. v. FERC*, 125 F.4th 229, 238 (D.C. Cir. 2025) (citing 16 U.S.C. § 824(b)(1)).

the states in the MISO footprint direct their utilities to meet resource adequacy requirements.[115] Notably, FERC "has consistently rejected a one-size-fits all approach to resource adequacy in the various RTOs/ISOs due, in large part, to significant differences between each region and also due to the well-established tenet that there can be more than one just and reasonable rate."[116] FERC has recognized that these differences set MISO apart from other RTOs/ISOs in meaningful ways. First, "[t]he vast majority (approximately 90 percent) of MISO's load is served by vertically integrated utilities over which state and local authorities play an active role in ensuring resource adequacy. In fact, even states with retail competition (i.e., Illinois and Michigan) have played an active role in ensuring resource adequacy."[117] Second, FERC has also recognized that "MISO's resource adequacy construct is designed specifically to complement state mechanisms" and "supports the independent authority of state regulators for resource adequacy and facilitates resource adequacy goals with state regulators that have decision-making authority over the amount and types of resources that are necessary to meet shared objectives."[118] Applying Section 201(b) of the FPA, the D.C. Circuit has similarly explained that states have the authority "to take any other action in their role as regulators of generation facilities without direct interference from the Commission."[119]

As the reliability operator, MISO is responsible for ensuring reliability for the 15 states that make up its footprint. As a result of this unique resource adequacy and reliability construct, collaborating closely with the states/RERRAs was a necessary part of creating the original ERAS process. Courts have recognized that FERC may not prevent a state "from using the resources [the state] has chosen to promote" and that "[t]he states may use any resource they wish to secure the capacity they need."[120] It is incumbent upon the Interconnection Customer to identify the specific need(s) its project will address and upon the states or RERRAs to notify MISO that these projects in fact merit expedited study so that they can be available promptly if approved through the

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[115] *See* MISO, *Planning Resource Auction*, MISO, ("MISO's resource adequacy construct complements the jurisdiction that regulatory authorities have in determining the necessary level of adequacy. It also works in concert utilities that provide demand forecasts that help drive the development of local and regional requirements.") https://www.misoenergy.org/planning/resource-adequacy2/resource-adequacy/#t=10&p=0&s=FileName&sd=desc. MISO runs a centralized capacity auction, known as the planning resource auction, but also allows LSEs to meet the resource adequacy requirement by submitting a fixed resource adequacy plan or through bilateral contracting. MISO, *Planning Resource Auction: Results for Planning Year 2024-25* (Apr. 25, 2024), 2024 PRA Results Posting 20240425632665.pdf.

[116] *Cxa La Paloma, LLC*, 165 FERC ¶ 61,148 at P 76 (2018).

[117] *Midcontinent Indep. Sys. Operator, Inc.*, 162 FERC ¶ 61,176 at P 67 (2018).

[118] *Midcontinent Indep. Sys. Operator, Inc.*, 170 FERC ¶ 61,215 at P 118 (2020).

[119] *Connecticut Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (D.C. Cir. 2009).

[120] *New Jersey Board of Public Utilities v. FERC*, 744 F.3d 74, 96-97 (3d Cir. 2014) (quoting *Connecticut Dep't of Pub. Util. Control*, 569 F.3d at 481-82.

applicable RERRA's regulations and processes. The states have many different processes for identifying these needs—some utilize top-down integrated resource planning, some utilize subsidies to encourage certain resource classes, and others directly procure new generation mix toward resources. MISO simply facilitates the ERAS process, which enables projects addressing resource adequacy and/or reliability needs to be reviewed in an expedited manner.

MISO appreciates the Commission's recognition of the RERRAs' "authority, responsibilities, and expert assessment of their resource adequacy needs" and has worked to reflect their responsibility in its refined ERAS proposal.[121] In its refined proposal, MISO has worked to describe how the ERAS process is sufficiently targeted to study *only* interconnection requests that are needed to meet the anticipated shortfall in generating capacity. MISO cannot establish a process on its own—it must implement a process that all 15 of its member-states can participate in. To that end, MISO is looking to the RERRAs to verify that the new, incremental load addition claimed by the Interconnection Customer is valid and not otherwise included in a resource plan or other process under the RERRA's purview or a resource adequacy deficiency that the ERAS projects are being proposed to address. Certain elements are required and MISO needs several parties to be actively involved in ERAS for it to work both legally and practically: a time-critical resource adequacy and/or reliability need must exist, a project applicant must propose an ERAS project to address that need, the RERRA must verify that the new, incremental load is valid or the resource adequacy deficiency exists. Finally, MISO needs to provide the process to enable the load need to be timely addressed. MISO's refined proposal fully incorporates each of these requirements and in way that encourages participation across its footprint.

III. THE PROPOSED REVISIONS ARE JUST AND REASONABLE

FERC applies an independent entity variation standard to evaluate proposals by RTOs and ISOs for revisions to the procedures outlined in Order No. 2003 and Order No. 2023.[122] Consistent with Order Nos. 2003 and 2023, MISO may seek variations from the *pro forma* Large Generator Interconnection Procedures ("LGIP") and Large Generator Interconnection Agreement ("LGIA") if those variations "are just, reasonable, not unduly discriminatory or preferential, and accomplish the purpose of " the terms proposed in Order Nos. 2003 and Order 2023.[123]

MISO's refined ERAS proposal meets this standard. The instant filing addresses a significant and concrete need that was identified and confirmed in the MISO stakeholder process for the original ERAS filing, numerous load forecasts, and by MISO in its administration as the reliability operator for the midcontinent. The supporting evidence demonstrates that the current

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121 ERAS Order at P 203.

122 Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at PP 822-827; Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160 at P 759.

123 Order No. 2003, 104 FERC ¶ 61,103 at PP 825-826; Order No. 2023, 184 FERC ¶ 61,054 at P 1764.

queue mechanisms will not be able to effectively address the resource adequacy and/or reliability needs that the states have in the short-term. MISO is proposing to study a capped number of ERAS projects on a serial basis to accelerate the review time so that urgently needed and "shovel ready" projects are able to reach a GIA faster. Utilizing serial studies for ERAS accomplishes the purpose of Order Nos. 2003 and 2023 by minimizing the restudy risk that is inherent to multi-phase cluster studies so ERAS projects can be built quickly, without the risk of cascading restudies. Although the use of cluster studies is appropriate for the large queue volume seen in MISO's Definitive Planning Phase ("DPP") process, the use of serial studies for ERAS will allow MISO to quickly study ERAS projects to address resource adequacy and/or reliability concerns and to meet the goals of the temporary ERAS process. MISO requests that the Commission find all Tariff revisions proposed in this filing just and reasonable and consistent with the goals of Order No. 2003 and Order No. 2023 because "they foster[] increased development of economic generation by reducing interconnection costs and time[.]"[124]

The Tariff revisions proposed in this filing are limited in scope and in impact on the generator interconnection queue but offer significant benefits in terms of addressing resource adequacy and reliability concerns in MISO, and therefore the Commission should accept them as just and reasonable.[125] Redlined and clean versions of the revised Tariff sheets are included as Tabs A and B, respectively.[126] This filing is also supported by the Direct Testimony of Andrew Witmeier, MISO's Director of Resource Utilization, included as Tab C with this filing.

A. Refinements Made to the ERAS Process

Following the Commission's order on its original ERAS filing, which provided helpful guidance for how MISO could move forward with ERAS, MISO worked to quickly implement changes to the proposed ERAS process to address the Commission's concerns while also crafting a process that can be started this year. To that end, MISO is proposing several changes to its original ERAS proposal, which it believes will address the Commission's concerns and other feedback received from stakeholders. The following figure demonstrates how MISO's ERAS proposal has evolved since its inception.

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[124] *Id.* at PP 11-12.

[125] *See* Tab A Redlines. In the event of a discrepancy between the redlines as described in this letter and those included in the attached Tariff sheets, MISO intends for the language in the attached Tariff sheets to govern.

[126] MISO notes that its compliance filing for FERC Orders 2023 and 2023-A, 184 FERC ¶ 61,054 (2023) 186 FERC ¶ 61,199 (2024)) ("Order No. 2023-A"), remain pending before the Commission in Docket No. ER24-2046-000. Thus, some of the proposed Tariff sections will require renumbering once MISO has received orders on this filing and its Order 2023 compliance. MISO intends to make a "true up" filing to address reconcile these versions of its Tariff promptly after receiving Commission orders accepting the applicable Tariff sections.

Figure 2: ERAS Proposal Changes from Inception

	Where we began	Original ERAS filing	Refined ERAS filing
Cap	N/A	N/A	No more than 10 projects studied per quarter and no more than 68 projects studied overall with an 8 project carve out for restructured states and a 10 project carve out for IPPs with agreements with entities other than LSEs
Applicants	Load Serving Entities	LSEs, IPPs, and DPP transfer projects meeting all requirements	No change
Process timeline	Project studied and GIA issued in 60 days	Quarterly cadence following established MISO timelines, receiving GIA in ~90 days	No change
Required documentation	RERRA acknowledgement	RERRA acknowledgement and one of the following: • LSE acknowledgment to self-supply • PPA between IC and load or its LSE • Build-Own-Transfer Agreement • Other agreement between applicant and load, or its LSE, stating project will meet RA or reliability need	RERRA verification and one of the following: • LSE acknowledgment to self-supply • PPA between IC and load or its LSE • Build-Own-Transfer Agreement • Other agreement between applicant and load, or its LSE, stating project will meet RA or reliability need
Identification of need	N/A	Description of need in ERAS application	IC must identify specific load addition and/or RA deficiency the project will address (MW value band, approximate location, etc.) and this information will be made public
Locational requirement	N/A	N/A	Project and RA and/or reliability need must be within the same Local Resource Zone
Size requirement	N/A	N/A	Interconnection Service must not exceed 150% of the identified MW need
Commercial Operation Date	Expected COD with 2-5 years	2025/26 applicants: 3 years from submission plus 3-year grace period; 2027/28 applicants: 12/31/2028 COD plus 3-year grace period	All applicants must have a COD within 3 years of submission plus a 3-year grace period
Penalties	Requested feedback after first PAC	Projects transferring from DPP process will be subject existing tariff language (e.g. AWP and Harm Calculations)	No change
Sunset	2028 / 2029	12/31/2028 or on the completion date of the 2027 DPP queue cycle, whichever first	ERAS will sunset at the earlier of the completion of the sixty-eighth ERAS study or on August 31, 2027

This chart demonstrates how MISO has worked with stakeholders to address concerns related to ERAS implementation and how its revised proposal responds to these concerns and Commission guidance. MISO is committed to proposing a process that can and will be used by its member states, which has required numerous iterations of the ERAS proposal.

1. Implementation of an ERAS Project and Quarterly Study Period Project Cap

In the Commission's order rejecting MISO's original ERAS filing, it emphasized that "MISO's proposed Tariff places no limit on the number of projects that could be entered into the ERAS process" and was concerned that "an ERAS queue with processing times for interconnection requests that are too lengthy to meet MISO's stated resource adequacy and reliability needs similar to the challenges with the current DPP queue."[127] In response to this feedback, MISO is now implementing a cap on the number of projects that may participate in ERAS: 68 projects total that will be studied in ERAS until the sunset date of August 31, 2027.[128] Additionally, MISO has carved out a maximum of 8 projects (of the total 68 ERAS projects) that may be submitted to serve

[127] ERAS Order at P 199.

[128] Witmeier Testimony at 26:11-19, 27:1-7, 49:6-15.

retail choice load and a maximum of 10 projects (of the total 68 ERAS projects) that may be submitted by IPPs with agreements with entities other than LSEs.[129] Thus, of the total 68 ERAS projects – 8 projects may be submitted to serve retail choice load, 10 projects may be submitted by IPPs, and 50 projects may be submitted by the remaining project applicants for non-retail choice states.

In addition to the total ERAS project cap and the carve outs, MISO is also implementing a cap of 10 projects that will be accepted and studied per ERAS quarterly cycle. Implementing a project cap per ERAS quarterly study period will enable MISO to adequately study each of the proposed projects in the accelerated timeframe that is required by ERAS.[130] The 10 projects per quarterly study cycle will be selected based on time of submission, but MISO also plans to implement a wait list for any projects that apply beyond the 10th project. Then MISO will implement a screening process to ensure that each of 10 proposed ERAS projects are not within the same geographic area or do not impact the same constraint. If any of the 10 projects are found to be within the same area or impacting the same constraint as another project in that same ERAS quarterly study period, then the project that was submitted later in time will be deferred to the next available quarterly cycle.[131] Then MISO will review any projects in the future quarterly cycles' waitlist to determine whether one of them can be moved up into the previous project's slot, which will require MISO to confirm that the next project is also not in the same geographic zone or addressing the same constraint as one of the nine other proposed projects that were already selected. The remaining projects submitted in that specific cycle that are not accepted for processing will be deferred to future ERAS cycles in order of submission time.

Capping the number of projects per cycle provides numerous benefits for MISO and generators. First, MISO anticipated that a small number of projects would participate per ERAS quarterly cycle, but the cap will ensure that no more than ten are able to be studied per cycle. This will enable MISO to complete the ERAS process more efficiently per project per cycle, which will facilitate the project obtaining an EGIA faster.[132] Second, the cap allows MISO to better plan for the number of projects that will be studied per cycle, which will help MISO efficiently coordinate internal resource needs to complete the studies on time. Knowing the number of projects will also help MISO plan the quarterly study periods out in a more even manner, which will also assist with providing MISO with the necessary information to make additional employee hires if necessary.[133] Third, capping the total number of projects that can participate in ERAS will further minimize the

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[129] *Id.* at 4:3-5, 26:17-19, 27:1-3.

[130] *Id.* at 4:5-6, 17:3-5, 27:8-15.

[131] *Id.* at 27:19-21, 28:1-3, 28:17-23.

[132] *Id.* at 27:8-15.

[133] *Id.* at 17:1-8.

impact on the DPP queue. While MISO stands by its original assertions that the ERAS process will have no impact on projects in the DPP queue and that the strict entry requirements will effectively limit submissions, expressly capping the number of projects that can participate in ERAS will further ensure that there are no negative impacts to projects currently in the queue.[134] Finally, the Commission found PJM's RRI cap to be "reasonably balanced the need to address PJM's resource adequacy challenges with the need to avoid an influx of projects that could overwhelm PJM's interconnection process and lead to further delays, exacerbating the current inability of projects to come online in the near."[135] MISO has the same goal, but plans to spread the number of projects submitted over a slightly longer time period to allow parties time to fully prepare their projects to participate in ERAS.

2. Updating the RERRA Notification Requirement

To reflect the unique jurisdictional authority the states have over generation facilities and resource adequacy needs within their borders, MISO worked closely with OMS to craft the original language that would have allowed a state or RERRA to notify MISO that a proposed project should be considered for the ERAS process in order to meet a claimed resource adequacy and/or reliability need in its jurisdiction. Following the Commission's order, MISO recognized that it needed to change the RERRA requirement and has proposed updated language, which is provided below, in the tariff. In the ERAS application itself, the Interconnection Customer will identify the specific need that its project will address.[136] The Commission noted in its order that "MISO has not demonstrated that the proposed Tariff language is tailored to ensure that only those resources capable of addressing identified near-term resource adequacy or reliability needs are eligible for expedited study through the ERAS process."[137]

Over the past several weeks, MISO has made necessary adjustments to the RERRA language in the ERAS proposal based on FERC's guidance and stakeholder input. To better tailor the RERRA notification to resource adequacy needs, MISO updated the language of the requirement to the following:

> A request for processing through the Expedited Resource Addition Study made by an Interconnection Customer must meet the requirements listed in Section 3.3.1 above, plus the following requirements:

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134 Witmeier Testimony at 53:9-21, 54:1.

135 ERAS Order at P 200.

136 *See* Tab A Redlines, Attachment X, Section 3.3.1.

137 ERAS Order at P 202.

1. The Interconnection Request shall be accompanied by a written verification from the RERRA (or its documented representative) where the load to be served by the Generating Facility is located, subject to the procedures or methods the RERRA requires, that either:

i. the new, incremental load addition claimed by the Interconnection Customer is valid and not otherwise included in a resource plan or other process under the RERRA's purview.

a. The RERRA (or its documented representative) may provide such written verification in conjunction with another state or municipal agency or official (e.g. economic development authority or governor's office) to verify the new, incremental load addition above.

or

ii. the Generating Facility proposed by the Interconnection Customer will address a resource adequacy deficiency as determined by the RERRA, State, Load Serving Entity, or Interconnection Customer. The determination can be supported by:

a. A state energy forecast, or other forward-looking forecast;
b. Commencement of a state proceeding;
c. Review of a RERRA, LSE, or other state resource plan or document, which may include, but is not limited to: integrated resource plans, procurement plans, or other plan or study types;
d. Response to a Request for Proposals (RFP); or
e. Other process, or delegation of authority, as determined by the RERRA or RERRA regulations (including in retail choice states).

or

iii. If an Interconnection Customer's new Generating Facility will address a resource adequacy deficiency and will either:

(1) serve retail choice load located in a state that limits the amount of load that can select retail choice to a percentage of the electric utility's average weather-adjusted retail sales; or

(2) serve load in a retail choice state and will be located in a retail choice state other than one that limits the amount of load that can select retail choice to a percentage of the electric utility's average weather adjusted retail sales,

then the Interconnection Customer will indicate the specific load on the Interconnection Request in Section 4.s of Appendix 1 and provide the evidence of determination in (ii) above, but will not be required to include a written verification, from a RERRA as described in Section 3.9.1(a) or (b). The Transmission Provider shall notify the respective RERRA that an Interconnection Request for a new Generating Facility has been submitted requesting processing through the Expedited Resource Addition Study process and transmit a copy of the Interconnection Request to the respective RERRA. The RERRA shall have 10 Business Days from the date of the Transmission Provider's notification and the simultaneous transmittal of the copy of the Interconnection Request to notify the Transmission Provider that the Interconnection Request should not be considered in the ERAS process. If no such notice is received at the end of 10 Business Days or if the RERRA notifies the Transmission Provider of its non-opposition prior to the end of the 10 Business Days, the Interconnection Request shall be studied through the Expedited Resource Addition Study process provided it meets the requirements listed in Section 3.3.1 and Section 3.9.2.

A RERRA's written verification is not intended to constitute or provide evidence of any final determination of need or suitability of the project for any purpose by the issuing entity beyond requesting that the Transmission Provider apply the ERAS process for such project.

2. An executed agreement evidencing that the projects submitted for ERAS processing is intended to be used by the entity with the claimed resource adequacy and/or reliability need. Such agreement shall take one of the following forms:

a. A Load Serving Entity acknowledgement to self-supply;
b. A Power Purchase Agreement (PPA) or similar off-take agreement between the Interconnection Customer submitting the project for ERAS consideration and the entity with the load to be served (including, but not limited to, an Alternative Retail Electric Supplier or its Load Serving Entity);
c. An agreement that calls for the Interconnection Customer to develop the Generating Facility described in the Interconnection Request and subsequently transfer ownership or control of such Generating Facility (Build-Own-Transfer Agreement) to the entity with the load to be served (including, but not limited to, an Alternative Retail Electric Supplier or its Load Serving Entity); or

d. Other agreement between the entity submitting the Interconnection Request, including the RERRA verification letter as appropriate, and the entity with the load to be served (including, but not limited to, an Alternative Retail Electric Supplier or its Load Serving Entity), stating that the ERAS project will be used to meet an identified resource adequacy deficiency.[138]

There are several aspects of the RERRA language that MISO is proposing to add to its Tariff and that MISO wishes to highlight. First, the RERRA, where the load will be located, must verify to MISO that the new, incremental load addition is valid and is not currently included in a plan or other procedure under the RERRA's purview or the Generating Facility will address an identified resource adequacy deficiency within that RERRA's footprint.[139] The verification may take any form that works for a specific state, but it must be made by a RERRA or a RERRA's designated representative, and it must be submitted in writing to MISO. MISO changed the details of this requirement to better target the resource adequacy driver the ERAS project is addressing and to ensure that the RERRA verifies that project will address a new load addition or resource adequacy deficiency in its footprint. The ERAS construct is a vehicle intended to achieve a narrow but important purpose: address near-term resource adequacy and/or reliability need claimed by an Interconnection Customer in a RERRA. Requiring that the RERRA verify to MISO that there is a valid, new, incremental load not already planned for or that the proposed project will address an identified resource adequacy deficiency is critical to maintaining this limited scope. Assuming the proposed project meets all the other ERAS requirements, MISO will accept the RERRA's verification and the project will be processed accordingly.

As for the second section of the RERRA language, applicants are still required to provide an executed agreement evidencing that the project submitted for ERAS is intended to be used by the entity with the claimed resource adequacy or reliability need, MISO added this language to ensure that any proposed ERAS project is directly tied to a specific load need. The executed agreement ensures that the project is one that the entity with the load to be served plans to use to address the need, and not simply a speculative project whose developers do not have any commercial arrangement to satisfy the need.[140] For example, an Interconnection Customer that has an agreement with a data center developer for the generation to serve that load is differently situated from a group of Interconnection Customers who are entering the queue with the hope of pitching their generation project to the developer. If the proposed ERAS projects do not meet

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138 *See* Tab A Redlines, GIP Section 3.9.1.

139 *Id.*

140 Witmeier Testimony at 7:3-5, 41:1-3, 41:17-23, 42:1-2.While such optimistic submissions may be features of Interconnection Requests submitted into MISO's Definitive Planning Phase ("DPP"), these contribute to a high volume (and high drop out rate) of Interconnection Requests in the queue. ERAS is intended to have a narrower scope and be used by highly certain projects addressing urgent needs.

these requirements as well as the other ERAS eligibility requirements, then they may submit their project to the generator interconnection queue. This requirement pairs the proposed project with a specific need, mitigating overuse concerns.

Collectively, these requirements narrow ERAS projects to only those for which a claim of need is stated, for which the applicable RERRA has provided verification that there is a valid, new, incremental load not already planned for or that the proposed project will address an identified resource adequacy deficiency, and for which an executed agreement exists connecting that need to the specific project. MISO also added a third section to the RERRA language to incorporate the retail states—Illinois and a portion of Michigan—into the ERAS process to address resource adequacy deficiencies in those states.[141] The proposed language states that if an Interconnection Customer's new Generating Facility will serve a retail choice load then the Interconnection Customer will need to submit demonstration of the resource adequacy deficiency, but will not be required to include a written verification from a RERRA.[142] Rather, MISO will notify the respective RERRA in the retail state that an Interconnection Request was submitted requesting processing in ERAS and will send a copy of the request to the relevant RERRA. The RERRA will then have 10 business days from receipt of the notification from MISO to state that the Interconnection Request should *not* be considered in the ERAS process.[143] This proposal recognizes that these areas do not have to seek approval from their RERRA and recognizes the existence of Alternative Retail Electric Suppliers in these areas as other entities that serve load. Thus, the new proposal better facilitates use of the ERAS process in Illinois and the retail sections of Michigan without changing the role or requirements applicable to RERRAs in other parts of MISO's footprint.

To recognize and reflect the states' authority over resource adequacy, MISO retained the language indicating that a RERRA's written verification to MISO regarding a proposed ERAS project "was not intended to constitute or provide evidence of any final determination of need or suitability of the project for any purpose by the issuing entity" beyond requesting that MISO apply the ERAS process to the project.[144] MISO understands that each RERRA has a distinct and separate regulatory process for the approval of energy projects within its jurisdiction and did not want participation in the ERAS process to be interpreted as MISO *directing* the RERRA to approve certain projects over others. It also ensures that the notification does not pre-determine any outcome of an applicable state process. Even if a project is approved to participate in ERAS, the LSE or developer must still receive state approval through the state's corresponding regulatory review process whether that be before the state public utility commission or the RERRA. MISO is simply proposing ERAS as a tool that may be utilized to address short-term

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141 *See* Tab A Redlines, GIP Section 3.9.1.

142 *Id.*

143 *Id.*

144 *Id.*

resource adequacy and/or reliability needs—the states are not required to participate in or to utilize ERAS.

3. Establishing a Stronger Nexus to Resource Adequacy Deficiencies

In its ERAS order, the Commission also found that MISO's proposal did not "sufficiently describe how the ERAS process is sufficiently targeted to study only interconnection requests needed to meet the anticipated shortfall in generating capacity described by MISO."[145] The Commission also pointed to PJM utilizing its locational deliverability areas and CAISO's system need criterion to target the proposed projects to areas with resource adequacy and/or reliability needs.[146] To better establish the nexus between the load need and the ERAS project, MISO is now requiring that the proposed ERAS project and the load addressing the resource adequacy and/or reliability need be located in the same Local Resource Zone ("LRZ").[147] This will ensure that the generation will support Local Clearing Requirements ("LCR"), and prevent ERAS projects from driving import or export concerns if the ERAS project is located in a different zone, unless the project applicant can demonstrate that the use of a Generating Facility not in the same LRZ was included in a resource filing or other submission made to the RERRA. MISO has ten geographic areas that are identified as Local Resource Zones and generally consist of one state or portions of several states.

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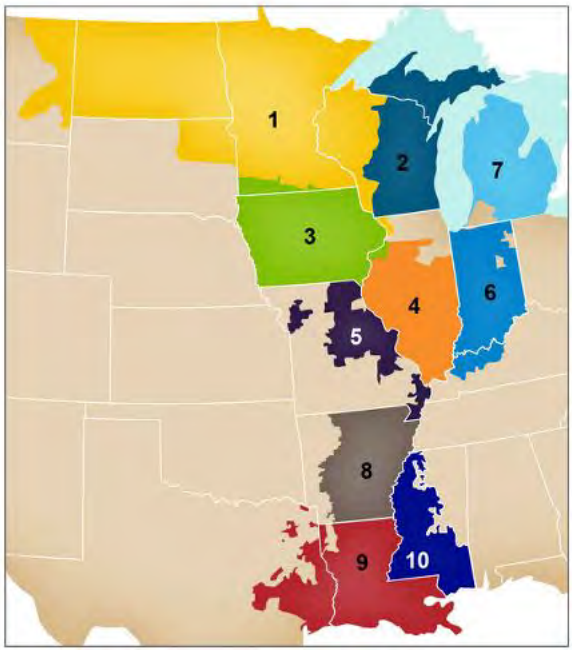
[145] ERAS Order at P 201.

[146] *Id.* at P 202.

[147] Witmeier Testimony at 4:10-15, 30:10-16, 32:4-16, 41:14-15, 61:17-19.

Figure 3: MISO Local Resource Zones[148]



MISO recognizes that that some LSEs span multiple LRZs and that LSEs regularly rely on resources from other zones to support their load requirements. MISO is requiring that the ERAS project be within the same LRZ as the load it is addressing unless the project applicant can demonstrate that the use of a Generating Facility not in the same LRZ was included in a resource filing or other submission made to the relevant RERRA.[149] Thus, if the ERAS project is located outside of the LRZ where the load need is located, then it will need to provide an Integrated Resource Plan ("IRP") or a comparable document that has been filed with the RERRA with its ERAS application.[150]

When applying to ERAS, the Interconnection Customer must identify the specific load addition and/or resource adequacy deficiency that the project will address including the project location and the expected MW value. The project must also not exceed 150% of the identified need based

[148] Tariff FERC Electric Tariff, ATTACHMENT VV, *Map of Local Resource Zone Boundaries*, available at: https://docs.misoenergy.org/miso12-legalcontent/Attachment_VV_-_MAP_of_Local_Resource_Zone_Boundaries.pdf.

[149] Witmeier Testimony at 4:10-15, 30:10-16, 32:4-16, 41:14-1516.

[150] Witmeier Testimony at 30:10-16.

on interconnection service.[151] MISO recognizes that other RTOs have utilized accredited capacity limitations, but since accredited capacity depending on the fuel type can be lower than 100% for many resources, MISO's limitation is aimed at tightening the nexus between the need claimed and what facility is being built without creating different rules for different resource types. This will enable MISO to better establish a connection between the identified load need and the ERAS project while also limiting the amount of service that may be requested to address the load need plus a reasonable margin. This methodology will facilitate the efficient implementation of ERAS and is not an overly complicated formula for determining the amount of need the ERAS project may address.[152] These revisions ensure a stronger tie between the ERAS project and the resource adequacy deficiency that it is addressing.

4. Increasing Transparency in the ERAS Process

MISO understands that this is a unique process that is being implemented for a very specific purpose but is committed to being transparent about the projects that participate in ERAS. While refining the ERAS proposal, MISO is making several changes to the ERAS application in order to increase transparency in the process. MISO plans to publish an ERAS webpage that will provide a significant amount of information regarding each ERAS project. To that end, an ERAS Interconnection Request must identify the claimed resource adequacy and/or reliability need(s) for which it is being submitted. This must include the location of the project—i.e. the county and state of the Generating Facility site, the electrical bus location(s), and the Local Resource Zone. The ERAS Interconnection Request must identify the load to be served via the off-take agreement as well as the peak demand for electricity in MWs as the amount of Interconnection Service requested must not exceed 150% of the identified MW need, and the location of the load to be served (i.e. the county and state, and the Local Resource Zone).

As part of the ERAS application, project applicants are also required to include a non-confidential summary of information that MISO can publish on its webpage. The required information that will be provided by the project applicant must include the following: the developer proposing the ERAS project, the MW range of need the ERAS project is addressing, the LRZ region where the ERAS project is located, and a general description of the driver of the load need (i.e., data center, manufacturing plant, etc.). MISO will also publish the RERRA that submitted a verification for each ERAS project, the specific carve out the project falls within, and the specific ERAS quarterly study cycle that the proposed project will be studied in once MISO has completed its screening process per ERAS cycle.

MISO is committed to ensuring that information about the ERAS process is easily accessible both for potential project applicants but also for other stakeholders in the energy industry. MISO also plans to publish an informational guide for potential ERAS applicants that addresses many

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[151] *See* Tab A Redlines, GIP Section 3.3.1.

[152] Witmeier Testimony at 43:1-19, 42:1-2.

common questions and problems that an applicant might be faced with when submitting its ERAS project. MISO believes that providing numerous cycles for ERAS projects to participate in will ensure that the ideal projects are proposed for ERAS and that potential project applicants have time to fully prepare their project before applying.

B. The ERAS Process is Balanced and Narrowly Tailored

ERAS was crafted to target projects that can meet resource adequacy and reliability needs quickly while also maintaining developer, fuel, and technology neutrality. MISO developed this filing based on its determination of how to best address its resource adequacy needs given its unique make up of primarily vertically integrated utilities across many different state and RERRA jurisdictions. The revised filing now incorporates the retail states so that all states in the MISO footprint may participate in ERAS. The LRZ requirement ensures that the ERAS project is located in the same area as the load need but also provides an exception for Generating Facilities not in the same LRZ that are included in a resource filing or other submission made to the relevant RERRA. State and RERRA involvement in ERAS ensures that the proposed ERAS projects are necessary to meet resource adequacy and reliability needs while also not favoring one kind of project or project developer.

These proposed revisions are properly tailored to ensure that projects capable of addressing identified resource adequacy or reliability needs participate in the ERAS process. Moreover, the new ERAS quarterly project processing cap will ensure that the projects are spread over a longer time period, which allows for the studies to be completed on a regular cadence and allows MISO to better forecast its internal resource and employee needs. Due to these changes, ERAS will not risk "replicating the same backlogs and delays plaguing MISO's existing generation interconnection queue, which are what put MISO in its current situation in the first place."[153] This revised proposal has "practical limits on the volume of interconnection requests that will be studied, such that the proposal is tailored to meet the identified resource adequacy and reliability needs."[154]

The following section first describes the eligibility requirements that projects are expected to meet to participate in ERAS. These eligibility requirements are critical for ensuring that the projects that are studied in the ERAS process are truly "shovel ready" and can be implemented in the very near term. The section then explains how the refined ERAS proposal ensures that ERAS projects will not harm existing projects in the general interconnection queue and how the ERAS project cap is a further safeguard to that end. MISO is committed to ensuring this process works for as many stakeholders as possible while also addressing the near-term resource adequacy and reliability needs in its footprint.

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[153] ERAS Order, Comm'r Rosner concurrence at P 1.

[154] *Id.*

1. ERAS Has Strict Eligibility Requirements

Over the past several years, MISO has pursued numerous avenues to address its near-term resource adequacy issues including improving GIP procedures, implementing a queue cap, and making other queue improvements, but the benefits of these updates will be unable to address or fill the identified resource gap in the short-term.[155] The continued large volumes of Generator Interconnection requests and accumulating backlog have delayed resource additions from obtaining executed GIAs. These delays are exacerbated by supply chain bottlenecks, permitting delays, and other commercial challenges that plague projects in the queue and those with signed interconnection agreements. The current queue cycle takes 3-4 years and late-stage dropouts from 2020-2022 resulted in queue re-studies and prevented the processing of later cycles. Concurrently, states are seeing extreme load growth due to economic development and new, large spot load additions but lack the ability to quickly add new resources.[156] To address this clear and immediate need, ERAS was created to facilitate the completion of projects that are "shovel ready"—projects that can truly address the shortfalls identified by numerous load forecasts.

To that end, MISO is implementing stringent eligibility requirements for participation in ERAS to only allow projects that are commercially viable within the next few years. In addition to the requirements addressed in the previous section—the RERRA notification and executed agreement—proposed ERAS projects must also meet other eligibility requirements. First, to participate in ERAS, an Interconnection Customer must pay a non-refundable application fee of $100,000, a milestone M2 payment of $24,000 per MW, and, upon signing the EGIA, agree to pay for any associated network upgrades even if the project is ultimately withdrawn from ERAS. The purpose of these financial requirements is to minimize the number of speculative projects applying to ERAS and to ensure that the projects that are applying truly are ready to be built and will serve an identified need.[157] Second, MISO is requiring that an ERAS project's EGIA commercial operation date be within three years of project submission. This requirement is focused on identifying the projects that are truly "shovel ready" and can be fully operational in the next five years.[158] Third, an ERAS project must also be able to demonstrate 100% Site Control for the generator and point of interconnection upon submission to MISO. All evidence of Site Control must be supplied at the time the ERAS application is submitted to MISO.[159] Finally, ERAS

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[155] Witmeier Testimony at 8:3-21, 9:1-2.

[156] *Id.*

[157] *Id.*

[158] *Id.*

[159] *Id.*

projects must meet capacity resource requirements and therefore must request Network Resource Interconnection Service (NRIS).

Since MISO's intent in establishing ERAS is to identify projects that are able to address resource adequacy and/or reliability needs in the short-term, existing projects that have not reached Decision Point II ("DP2") in the 2022, 2023, and later cycles will be eligible to transfer to ERAS.[160] MISO is currently aware of several existing projects in the generator interconnection queue that could apply to participate in ERAS and have plans to consider that option.[161] Existing projects may remain in the DPP cycle while applying for ERAS, but once admitted to ERAS, the projects must withdraw from the DPP cycle and will be subject to Automatic Withdrawal Penalties and Harm Penalties.[162] MISO is requiring these penalties because it recognizes that when projects drop out of the generator interconnection queue, the withdrawal causes harm to the other projects in the cluster. Moreover, after applying, if the existing project is deemed ineligible to participate in ERAS process, then it will forfeit the $100,000 D1 payment provided with the ERAS application and remain in its original queue position.[163] When an existing project leaves the DPP process and successfully transfers to ERAS, it becomes a new Interconnection Request. Therefore, modifications may be made to the project at the time of application. Modifications are allowed to better tailor the Interconnection Request to the claimed need. Any transfers into ERAS is made under new Interconnection Request and is technically not tied to the original request.[164]

Limiting each ERAS cycle to 10 projects will allow MISO to study each project individually in the order submitted, rather than as a group.[165] This serial approach will also allow the developer to perform their own initial studies without the uncertainty of what other generation projects will be in the study as well. Enabling serial studies of the proposed projects is a key feature of ERAS. It affords ERAS Interconnection Requests a better understanding of their impact on the system when looking to address the load need. The traditional challenges related with reviewing projects on a serial basis are not present with ERAS because there will be a much smaller number of Interconnection Requests to process and they are expected to be geographically and

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160 Witmeier Testimony at 15:5-17.

161 Witmeier Testimony at 15:18-21.

162 These penalties are outlined in Attachment X, Sections 7.6.2.1.1 and 7.8 respectively.

163 Witmeier Testimony at 15:21-23, 16:1-4.

164 *Id.*

165 *Id.*

electrically dispersed across the MISO footprint.[166] This is distinguished from the DPP queue where serial studies are difficult, if not impossible, due to the extremely high number of applications per cycle and the high probability of those projects being in the same area.[167] If several ERAS projects in the same quarterly study cycle are located in the same geographical area or impact the same constraint, then MISO will study the project with the earliest submission time in that cycle, and will study the second request in the next available ERAS quarterly study cycle. However, MISO is not anticipating that this will occur very often due to the project cap per cycle, its large geographic footprint, and the strict eligibility requirements to participate in ERAS.[168]

Regarding Affected Systems Studies ("AFS"), neighboring systems will have the right to evaluate the impact of ERAS projects on their systems, just as with projects in the DPP. Any ERAS project that meets JTIQ criteria will be subject to JTIQ.[169] Where available, the affected system study Network Upgrades will be documented in the EGIA. Where AFS analysis is not available for inclusion in the final EGIA, the EGIA will be executed by all parties and MISO will provide any updated analysis when received from the applicable Affected System. But ERAS projects will still be responsible for all required Network Upgrades even if the ERAS project ultimately ends up terminating the EGIA.[170] MISO's proposal includes Tariff language to reflect that even if MISO only provided an estimate of potential network upgrade costs upon applying to ERAS, there will be a true up where either MISO would refund an overcollection of costs or the Interconnection Customer would pay the difference to meet the actual network upgrade costs.[171] MISO added this requirement to ensure that the ERAS project remains responsible for AFS costs. MISO is dedicated to protecting the Generator Interconnection Queue and views this requirement as a further guardrail to protect active projects in the DPP while ensuring that only eligible, ready projects are processed through ERAS.

Finally, to reflect that ERAS is a short-term solution for a near-term problem, MISO is requiring that ERAS projects have a COD three years after the project's submission date unless the project was deferred to a later quarterly study cycle. This caveat is necessary to insulate Interconnection Customers from the impact of deferrals due to the operation of the quarterly study cap. MISO has also written a sunset date for ERAS into the Tariff. ERAS will sunset by August

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[166] MISO processes hundreds of Interconnection Requests through its DPP each year with 600 in its 2023 cycle. Based on extensive discussion with RERRAs and other stakeholders, MISO projects fewer than twenty projects will qualify for ERAS in 2025.

[167] Witmeier Testimony at 5:16-19.

[168] *Id.*

[169] *See* Tab A Redlines, GIP Section 7.3.2.3.1.

[170] Witmeier Testimony at 6:12-16, 34:8-15.

[171] *See* Tab A Redlines, GIP Sections 3.9.6, 3.9.6.1, 3.9.6.2, and 3.9.6.3.

31, 2027, or when it has completed 68 ERAS Interconnection Request studies, whichever occurs first.[172] MISO made this requirement narrower in response to stakeholder feedback as well as Commission feedback stating that MISO's original ERAS proposal was unlimited in nature.[173]

MISO has implemented these stringent eligibility requirements for ERAS to ensure that the projects participating in it are truly "shovel ready" and capable of addressing the states' resource adequacy and/or reliability needs in the near-term. The ERAS eligibility requirements act as a filter to restrict ERAS entry to only those projects that are commercially ready, are needed to respond to a specific resource adequacy or reliability problem and can be completed in the next few years.

2. The Cap Will Expedite ERAS Studies and Prevent Harm to the Queue

A significant concern that was identified in the process of crafting ERAS is the impact ERAS will have on the other queue studies. ERAS has been cautiously crafted to avoid supplanting the DPP or harming projects in the queue. MISO worked carefully to address these concerns and emphasizes its commitment to prioritizing the use and improvement of MISO's generator interconnection queue. Projects in the generator interconnection queue will not be competing with ERAS projects for transmission capacity because although both ERAS and DPP projects will utilize the same MTEP base case, they will have different generator assumptions.[174] ERAS will include only approved Generating Facilities, where the DPP will include all queued projects which includes a significant amount of speculative projects.[175]

As Andrew Witmeier explains in his direct testimony attached to this letter, before every ERAS cycle, all Interconnection Requests with a GIA approved since the last base case was created will be added to the base case for the following ERAS cycle but they are not included in any ongoing DPP studies.[176] The base case for each DPP cycle is never updated once the study process is kicked off except for generation changes due to Interconnection Request withdraws or generator retirements.[177] This ensures that the transmission capacity made available for DPP projects is not

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[172] *Id.* at Section 3.9.9.

[173] *See* Tab A Redlines, GIP Section 3.3.1; ERAS Order at P 203.

[174] Witmeier Testimony at 17:9-19.

[175] *Id.*

[176] *Id.*

[177] *Id.*

being taken away by ERAS Interconnection Requests approved outside of the DPP cycle.[178] This also insulates existing DPP projects from negatives impacts or cost shifts due to the existence of the ERAS process.[179]

By providing ERAS as a tool for the states to utilize, MISO is not looking to displace or overshadow the generator interconnection queue, rather it is providing a process to address a near-term, identified resource adequacy need. The ERAS eligibility requirements are more rigorous than the DPP requirements and are capped both in total number of projects and number of study cycles, which ensures a smaller applicant pool of more earnest project applicants for ERAS and maintains the integrity of the generator interconnection queue. A comparison of the different eligibility requirements is included below.

C. The ERAS Process is Not Unduly Discriminatory and is Consistent with Open Access Requirements

In Order Nos. 888 and 2003, FERC aimed to prevent the discriminatory treatment of competitive generation by requiring open access transmission tariffs that are not "unduly discriminatory or anticompetitive" and that "offer third parties access on the same or comparable basis, and under the same or comparable terms and conditions …."[180] MISO's refined ERAS proposal remains in alignment with those requirements—it is not unduly discriminatory, it is not anticompetitive, and it provides third parties with access to the transmission system on the same or comparable basis. This section first explains why the ERAS proposal is not unduly discriminatory and then addresses how ERAS meets FERC's open access requirements.

1. ERAS is Not Unduly Discriminatory

There is no restriction on the type or sponsor of projects that can apply to the ERAS process, which makes the application process non-discriminatory. MISO has also created carve outs to the total project cap for applicants that are uniquely situated like Independent Power Producers and developers serving retail choice states. These carve outs will allow these groups of applicants to participate on equal footing with other applicants proposing ERAS projects and must meet the same eligibility requirements to participate in ERAS. MISO added the carve out for IPPs to address concerns that LSEs had an advantage over other entities when submitting projects to

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178 *Id.*

179 *Id.*

180 Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,647. *See also Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, FERC Stats. & Regs. ¶ 31,146 (2003), *order on reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, *order on reh'g*, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), order on reh'g, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007), cert. denied, 552 U.S. 1230 (2008).

ERAS. The carve out for the retail states also enables developers in those areas to participate in ERAS and set aside a portion of the projects to ensure they are able to participate.

Initially, MISO proposed only allowing LSEs, and those contracting with LSEs, to apply for ERAS. After receiving stakeholder feedback on this point while preparing its original ERAS filing, MISO expanded ERAS to allow any applicant to apply to ERAS as long as the applicant had an executed agreement for a specific load need. Under the revised ERAS process, an Independent Power Producer ("IPP"), LSE, or developer may apply to ERAS.[181] MISO's proposal to enable IPPs with an LSE offtake agreement to apply for ERAS addresses the unduly discriminatory concerns identified by the stakeholders and the 10 project carve out enables further participation for IPPs. Some stakeholders have protested that this is still favoring LSEs over other kinds of applicants and thus assert that ERAS is unduly discriminating against non-LSE participants. MISO disagrees. MISO has expanded the applicant pool to include developers that have contracted offtake agreements with a LSE to propose ERAS projects and added project cap carve outs to enable further participation by those IPPs that prefer to contract with the load source directly rather than the LSE. ERAS projects submitted by IPPs that have contracts with the LSE will not count towards the ten project cap. Thus, the ten project carve out exists to create a space designated specifically for IPPs, thus addressing concerns that LSEs may exhaust the ERAS cap before IPPs can submit their projects. This approach balances enabling broader participation with the need to ensure that ERAS does not become a general purpose alternative to the DPP or grow beyond a limited number of projects. Any Interconnection Customer that has a project that they believe is the most cost effective, ready, or best positioned resource to respond to an urgent resource adequacy need is encouraged to apply to participate in ERAS.

Under the revised ERAS proposal, developers will have comparable access to the ERAS process and may also execute commercial arrangements with load. Any other differences for project applicants are neither created nor exacerbated by MISO's Tariff.[182] The purpose of ERAS is to encourage the submission of projects that have been identified as responsive to a need and can be completed rapidly. Although MISO has previously stated that requiring executed agreements does not necessarily prove project readiness,[183] the executed agreement requirement serves a different purpose and provides additional value in the context of this filing. Specifically, requiring executed agreements for ERAS effectively ties the project to the claimed resource adequacy and/or reliability need. The process of securing the necessary agreements and acknowledgment by the RERRA may be competitive. The ERAS process simply moves that competition and development of commercial certainty to before the Interconnection Request is submitted, rather than while it is in queue. MISO has actively worked to reduce the risk of

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[181] Witmeier Testimony at 39:18-23, 1-7.

[182] ERAS offers a level playing field and contemplates that IPPs may be the entities that secure the agreement and RERRA notice for a given need.

[183] MISO Initial NOPR Comments, Docket No. RM22-14-000 (October 13, 2022).

speculative projects participating in ERAS and requiring executed agreements is one way to ensure that.

In addition to expanding the different kinds of applicants that can participate in ERAS, MISO is also allowing existing projects in the Generator Interconnection Queue to transfer to ERAS.[184] In the original ERAS filing, several stakeholders argued that ERAS would result in the unequal treatment of participants who have dutifully followed the traditional interconnection process. But MISO is allowing any existing projects to transfer to ERAS if the project is not past Decision Point II ("DP2"). MISO is prohibiting transfers after DP2 to protect the remaining projects in the queue by preventing any unplanned re-studies that could result from any late-stage transfers.[185] Also, MISO is requiring that existing projects that do transfer to ERAS pay all relevant withdrawal penalties in addition to making the non-refundable $100,000 D1 payment to participate in ERAS.[186] Due to these high financial stakes and the strict eligibility requirements for ERAS, MISO is not anticipating many transfers from the DPP process. Some stakeholders wanted greater transferability from the DPP to ERAS, MISO's proposal however reflects the compromise of protecting the existing queue while providing projects with the opportunity to transfer from the DPP to ERAS.

In addition to the different eligibility requirements between ERAS and the DPP process, MISO plans to coordinate the ERAS, EPR, and DPP studies to maximize efficiency and reduce any impact on each other.[187] MISO expects protestors to claim that the ERAS process will negatively impact existing projects that are currently included in the Generator Interconnection Queue. At numerous stakeholder meetings during the original ERAS filing, MISO stressed that this was not the case due to the way in which the studies are completed. The base case for MTEP, EPR, and ERAS projects is updated with all GIAs approved to date. Approved MTEP projects can be utilized for constraint mitigation in DPP, EPR, and ERAS projects studies. Additionally, Network Upgrades that are identified in ongoing MTEP studies that mitigate congestion in DPP and ERAS studies will remove the need for DPP and ERAS network upgrades once the MTEP project is approved.[188] Finally, ERAS projects will not harm projects currently studied in the DPP process by taking existing transmission capacity headroom from active projects ERAS and DPP use the same MTEP base case as a starting point and any headroom used by ERAS projects is not

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[184] Witmeier Testimony at 15:5-17.

[185] These projects are the ones that would receive the least benefit from ERAS given their degree of advancement through the DPP.

[186] Witmeier Testimony at 15:21-23, 16:1-4.

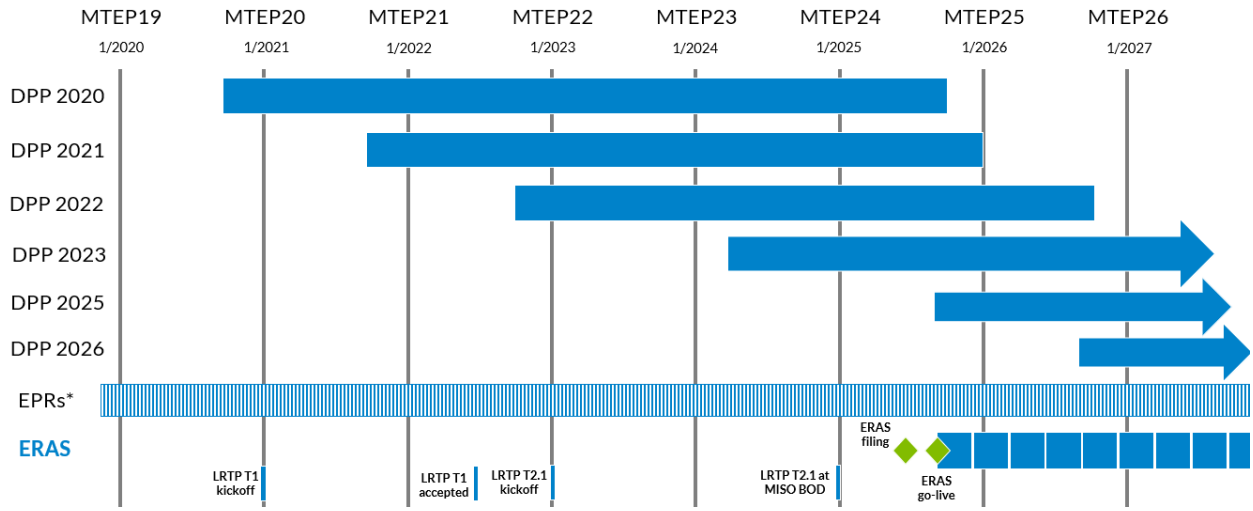
[187] The DPP is primarily described in section 7 of the GIP. See Tariff, Attach. X, GIP Section 7.

[188] *See* MISO BPM 15, Section 6.1.1.1.

deducted from the DPP model.[189] The output of the DPP and ERAS models are then reconciled in the next MTEP. This is consistent with how MISO reconciles currently effective parallel processes through the next MTEP base case. Thus, while it may be possible for over-allocation of capacity headroom to occur, this would not impact DPP projects and would be addressed through MTEP. Thus, ERAS projects will not have early access to newly available headroom related to Tranche 2.1 and will not disadvantage projects from 2025 queue cycle.

The chart below demonstrates the ongoing queue study cycles and the projects in those cycles are still using the transmission capacity that was available in the system at the time that model study started. If MISO approves an ERAS project that will utilize the transmission capacity in MTEP 24 and the DPP 23 is using MTEP 23, ERAS will not take away transmission capacity from any project in the 2023 queue cycle. Ongoing queue cycles interact with each other, but do not take transmission capacity or headroom from each other. Thus, ERAS projects will not take away transmission capacity for ongoing DPP cycles as the base case is not updated. Any overallocation that may occur will be identified and mitigated in the next MTEP cycle.

Figure 4: ERAS Will Integrate With Existing Study Processes[190]



ERAS provides all interconnection customers with a comparable opportunity to submit an interconnection request and compete to be studied under MISO's ERAS interconnection procedures. ERAS treats participants equally as long as they meet the eligibility criteria. All

189 Witmeier Testimony at 17:9-19.

190 *Expedited Resource Adequacy Study (ERAS) Workshop* at 10, (December 6, 2024), https://cdn.misoenergy.org/20241206%20Expedited%20Resource%20Adequacy%20Study%20(ERAS)%20Workshop665747.pdf.

ERAS applicants will be subject to the same rules and requirements on a comparable basis, regardless of fuel type, technology, or any other factors.

2. ERAS is Consistent with Open Access

MISO's interconnection procedures are part of an open access transmission tariff and thus MISO must offer access to the generator interconnection process on the same or comparable basis. Unlike some stakeholder assertions, ERAS is not providing priority access to its generator interconnection process for an exempted class of interconnection requests. The ERAS process is open, competitive, technology/fuel agnostic, and does not involve MISO favoring or selecting certain projects over others. This includes existing projects in the queue as MISO is not harming Interconnection Customers in the generator interconnection queue by using available headroom on the transmission system.

Once a project has met the strict eligibility requirements for ERAS, including the RERRA verification, it is allowed to participate in the ERAS process. Due to the jurisdictional split between the FERC and the states over resource adequacy and reliability, MISO's role is not to be in the middle of resource decision-making processes of the states or RERRAs.[191] Unlike PJM's Resource Reliability Initiative ("RRI") which clearly prioritizes projects on the ELCC Class Ratings, MISO is not going rank ERAS projects. The ERAS process does not unduly discriminate against or in favor of any type of resource or pre-existing project, which is unique from the PJM and CAISO's proposals that favor certain projects by giving higher weights to resources that are more reliable and consistent.[192] PJM's RRI process is aimed at enabling "a very limited injection of 50 projects that score high in measures PJM has identified as contributing to addressing reliability needs."[193] PJM specifically noted that 60% of its Transition Cycle #2 were intermittent resources but asserted its need for high-reliability value projects to meet its near-term resource adequacy needs.[194] Despite PJM's clear preference for certain kinds of projects that are not intermittent and placing a limit on the total number of projects that can participate, the Commission approved their proposal.[195]

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191 *See* 16 U.S.C. § 824(b)(1).

192 *PJM Interconnection, L.L.C.*, Docket No. ER25-712-000, PJM's Transmittal Letter (filed Dec. 13, 2024) ("PJM's RRI Transmittal Letter"); *California Independent System Operator Corporation*, Docket No. ER24-2671-000, CAISO's Transmittal Letter (filed Aug. 1, 2024).

193 PJM's RRI Transmittal Letter at 3.

194 *Id*.

195 *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084 at P 78 (2025). PJM awards 55 out of a possible 100 points for two attributes: unforced capacity ("UCAP") and effective load carrying capacity ("ELCC") that tend to favor certain, non-intermittent resource classes over others.

While the refined ERAS process is implementing a project cap, MISO will not rank or score submitted projects and is open to any applicant and any fuel source as long as the project meets ERAS eligibility requirements. Open access requirements and the states' jurisdiction over resource adequacy are not mutually exclusive. In the revised ERAS proposal, MISO is still not weighing any class of resources over others but rather is prioritizing projects that can be completed in the near-term to address specific looming resource adequacy shortfalls. MISO is also not sorting winner or loser ERAS applicants based on the specific attributes of each generating facility. Rather it is deferring to state jurisdiction over resource procurement and facilitating the identification of projects that will be completed in a short time period to address resource adequacy and reliability needs. The states can determine the best form of capacity that will meet their needs through the ERAS process. The ERAS process will also mitigate many of the identified co-location concerns heard in the industry as states will have the ability to quickly address large spot loads.[196]

In the original ERAS filing, some stakeholders asserted that ERAS violates open access by preferring certain LSE/RERRA-sponsored projects or that ERAS treats participants unequally by granting undue advantages to projects owned by LSEs. Many of the refinements made to the original ERAS filing address those complaints and aim to equalize the playing field between applicants. MISO's proposed Tariff language is clear that *any* Interconnection Customer may submit an ERAS project if it meets the requirement of supplying an executed agreement.[197] A non-LSE related Interconnection Customer could submit an agreement with a particular load that their generation will serve.[198] The RERRA will continue to have its applicable regulatory oversight over the LSE and still must verify the new, incremental load addition claimed by the Interconnection Customer is valid and not otherwise included in a resource plan or other process under the RERRA's purview or the Generating Facility will address a resource adequacy deficiency before the project can participate in ERAS.

Thus, the ERAS process treats all applicants on a comparable, not unduly discriminatory, basis that is consistent with FERC's open access requirements, subject to the ERAS eligibility requirements, which are applied uniformly across all applicants.

D. Substantial Evidence Supports the Need for ERAS

Substantial evidence supports MISO's need for ERAS. MISO has created ERAS to work in parallel with the DPP process to provide a process for non-speculative, shovel ready projects to be completed in 3-5 years. The ERAS process incorporates the states' primacy on resource adequacy while providing a pathway for those projects to be completed on an accelerated basis.

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196 *See* Co-Location Order, 190 FERC ¶ 61,115 (2025).

197 *See* Tab A Redlines, Section 3.9.1.

198 *See id.*

MISO's refined ERAS proposal addresses a real need that has been identified in numerous load forecasting reports, by the states, and in MISO's own experience as an independent system operator.[199] MISO's experience with a quickly changing industry and load growth is being witnessed across the country and by many other entities in the industry that have discussed similar experiences at technical conferences hosted by FERC including the recent conference on co-location.[200] Comments made during FERC's technical conference on resource adequacy recognized that there is a reliability crisis and that generators need to come online in the very near term to address the looming resource adequacy needs.[201] MISO recognizes these concerns and is working expeditiously to make changes to address those needs in the near-term. The supporting evidence demonstrates that the benefits of the current queue improvement mechanisms will take longer than is necessary to address the near-term resource adequacy needs.[202] The GIP improvement mechanism will improve the quality of the projects entering the queue, the Cap mechanism will address the quantity of projects entering the queue, and ERAS will supply the states with a mechanism to address resource adequacy and reliability needs in the next few years. The proposed ERAS revisions will benefit Interconnection Customers and other interconnection process participants by supplying a way for commercially ready, necessary projects to obtain a GIA quickly to address resource adequacy and reliability issues within the MISO footprint.

The original ERAS process was extensively reviewed and discussed in the stakeholder process and MISO adopted many stakeholder suggestions to ensure the process achieves what it aims to do.[203] The refined-ERAS procedures will ensure that Interconnection Customers applying to participate have projects that are ready to be completed.[204] MISO needs an effective tool to address resource adequacy and reliability needs now, which is why it worked expeditiously to refine its previous ERAS process and is now proposing an updated process that can be executed in a few months. By implementing the strict eligibility requirements, ERAS will increase certainty for Interconnection Customers by ensuring that all ERAS projects are "shovel ready" and are required to pay for any associated Network Upgrades even if they end up ultimately dropping out

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199 *See supra* notes 51-87; *see also*, Tab C, Direct Testimony of Andrew Witmeier.

200 *See supra* Section II.B.

201 *See supra* note 80.

202 2024 Cap Filing at 17 ("Although MISO's recent queue reforms contained many important measures to enhance the current queue process, these measures are expected to work over a period of time and may not allow MISO to immediately address the identified queue issues for the 2023 DPP cycle and reduce study cycle volume to a level that supports studies using realistic assumptions.").

203 *See supra* Section II.C.

204 *See supra* Section III.B.

of the process.[205] ERAS was carefully crafted to ensure that existing projects in the Generator Interconnection Queue will not be affected by the ERAS process, nor will those projects lose out on existing transmission capacity this is especially true now that MISO has capped the ERAS process to 68 projects total spread out over multiple cycles.[206] The existing queue will remain a priority for MISO. MISO does not view ERAS as infringing upon or negatively affecting the existing queue, but rather as an additional tool for states to utilize if eligible.

Establishing a separate process for projects addressing resource adequacy and/or reliability needs is not an unfamiliar concept at FERC. As it noted in the original ERAS Order, the Commission previously accepted similar proposals from CAISO and PJM.[207] MISO recognizes that the other RTOs utilized some form of a scoring matrix for proposed projects and that ERAS does not involve a similar methodology. Due to the states' responsibility for resource adequacy within their borders, MISO did not want to be considered the entity picking and choosing projects between the states. MISO also cannot require the states or RERRAs to participate in a specific way or impose a specific selection process for ERAS projects. Instead, it implemented a project cap, a cycle cap, a strengthened RERRA verification, more detailed application requirements, and strict eligibility requirements to ensure that only truly commercially viable projects will apply to participate in ERAS. MISO is striving to balance the unique differences found in its footprints with some of the characteristics found in other RTO/ISO's proposals.

Due to the very near-term, unexpected load growth that the MISO footprint is experiencing, MISO is proposing a refined process to review and finalize projects that can address these resource adequacy and/or reliability needs. ERAS strikes the right balance between significant competing interests and MISO providing the process to allow generation to come online to address short-term, claimed needs. The Generator Interconnection Queue will remain MISO's priority and focus as ERAS is a unique answer to a temporary and unanticipated problem and is capped both in number of projects and in length of time. Recognizing all the other changes MISO is making to the Generator Interconnection process, MISO fully expects that it will be reduced to one year by the time the ERAS process is designed to sunset. Complex problems commonly require creative solutions and ERAS is MISO's creative solution to the rapid evolution of the energy industry in our footprint.

MISO's refined ERAS proposal, described herein, is just and reasonable. ERAS is balanced in addressing the complex needs identified by numerous parties and is narrowly tailored to the identified resource adequacy and reliability needs. Addressing the looming resource adequacy needs in the MISO footprint requires that MISO and the states work together to provide solutions to the problem. Again, MISO views the ERAS process as simply a tool that states *may*

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[205] *See supra* Section III.B.2.

[206] *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084, at P 1 (2025) (RRI Order); *Cal. Indep. Sys. Operator Corp.*, 180 FERC ¶ 61,143.

[207] ERAS Order at P 202.

utilize to address their resource adequacy and/or reliability needs, even the retail choice states. But it also provides a process to ensure that proposed projects are shovel ready and are completed in a short time frame to address the looming resource adequacy and/or reliability needs. Finally, MISO is committed to working with stakeholders to address more generalized queue and industry challenges and ERAS will not change that.

IV. DESCRIPTION OF PROPOSED TARIFF REVISIONS[208]

The proposed Tariff revisions implement the ERAS process and are necessary to distinguish the key differences in how the ERAS process will operate in comparison to MISO's generator interconnection queue. Because the ERAS process is not a queue and is temporary in nature, it is important to clearly identify the differences for clarity and certainty. The instant filing includes ERAS-related revisions in Attachment X (Generator Interconnection Procedures), Attachment X, Appendix 1 (Interconnection Request), and Attachment X, Appendix 6 (Generator Interconnection Agreement).

A. Attachment X, Generator Interconnection Procedures

1. GIP Section 1

Section 1 contains definitions that are used throughout the GIP and its supporting attachments. The proposed new definitions are necessary to implement the ERAS process and to provide clarity and consistency throughout the GIP. In addition to new definitions related to ERAS processes, MISO proposes to revise the definition of "Commitment Projection," "Potential MW Total," and "JTIQ Screening Group, to incorporate MISO ERAS and SPP ERAS into the JTIQ Portfolio and reflect the capacity they will use.[209] "Interconnection Request" was edited to include a request for new generation capacity to be studied under ERAS. This change is necessary to properly document that ERAS projects will be studied separately from MISO's generator interconnection queue and will require a separate election in Appendix 1 to the GIP ("Interconnection Request for a Generating Facility") to be studied as an ERAS project. MISO added additional proposed revisions to include ERAS projects in JTIQ-related definitions to provide clarity that ERAS projects will be considered for JTIQ. MISO also added the definitions

[208] The proposed revisions for each proposal are presented together and in logical order for the purpose of discussion, not in order of importance.

[209] These updates reference both MISO's ERAS and SPP's ERAS projects given that SPP has filed its ERAS process in Commission Docket No. ER25-2296 and both MISO and SPP have filed revisions to update their JOA to reflect these processes in Commission Docket Nos. ER25-2297 and ER25-2298. The revised definitions proposed in this filing align with those filed in Commission Docket Nos. ER25-2297 and ER25-2298. In the event that the Commission accepts MISO' ERAS process but not SPP's, MISO would update the ERAS references in these definitions accordingly.

of Expedited Resource Addition Study (ERAS), Expedited Resource Addition Study Quarterly Study Period, Expedited Generator Interconnection Agreement (EGIA), Local Resource Zone (LRZ), and Relevant Electric Retail Regulatory Authority (RERRA), the latter two of which are defined in Module A.[210]

2. GIP Section 2.1

MISO proposes to add a subsection i to GIP Section 2.1 that governs the application of interconnection procedures.

> i. An Interconnection Request for a new Generating Facility to be studied through the Expedited Resource Addition Study process shall be evaluated pursuant to Section 3.9.2.

This subsection explains that a request for ERAS should be evaluated according to the procedure in GIP Section 3.9.2, which is a new Section MISO proposes to add for the implementation of the ERAS process. This addition is necessary to distinguish the process for evaluating requests for ERAS from other projects entering MISO's generator interconnection queue.

3. GIP Section 3.3.1

MISO proposes to revise Section 3.3.1, which encompasses the procedures for submitting an Interconnection Request. The revisions include clarifying language surrounding the timeline for submitting ERAS Interconnection Requests, where applications will be accepted while the ERAS process is in place, and where the application timeline will be posted to the MISO website. MISO also proposes to increase the Non-Refundable Deposit 1 (D1) to $100,000 for ERAS projects and to require an entry milestone (M2) of $24,000 per Megawatt for new Interconnection Service requested to ensure that ERAS projects are "shovel ready" and to prevent speculative projects from submitting to ERAS. MISO's DPP process contains three phases where three milestone payments are required. The PGIA process requires $8000 per Megawatt for each phase provided upfront, so to facilitate a similar, "one phase" ERAS study, MISO proposes to implement an equivalent milestone payment of $24,000 per Megawatt.

MISO also proposes revising Section 3.3.1 to require an ERAS Interconnection Request to identify the claimed resource adequacy and/or reliability need(s). The revisions include requiring the Interconnection Request to provide information including the location of any load as well as the MW amount of the proposed ERAS project. The revisions also require the ERAS project be located within the same Local Resource Zone, unless the project applicant can demonstrate that the use of a Generating Facility not in the same LRZ was included in a resource filing or other

[210] MISO Tariff, Module A.

submission made to the RERRA. Finally, the revisions limit the amount of Interconnection Service requested by the ERAS project to no more than 150% of the identified MW need. These changes were made to tighten the connection between the verified resource adequacy and/or reliability need with the relevant RERRA.

…

> An Interconnection Request for a Generating Facility requesting processing through the Expedited Resource Addition Study shall identify the claimed resource adequacy and/or reliability need(s) for which it is being submitted. This should include the location (i.e. the county and state, the electrical bus location(s), and the Local Resource Zone) of any load to be served via the off take agreement as well as the peak demand for electricity expected over any one hour period in MWs—the amount of Interconnection Service requested must not exceed 150 percent of the identified MW need. The Generating Facility and the associated resource adequacy and/or reliability need(s) must be within the same Local Resource Zone, unless the resource adequacy and/or reliability need is included in a resource filing made to the RERRA that is providing the verification required in Section 3.9.1.
> …

To further demonstrate that a project is "shovel ready," all documentation, milestone payments, deposits and any necessary data is required at the time of application. These up-front requirements will allow MISO to complete the study process within its estimated 90-day timeframe. Additionally, at the time of application, Interconnection Customers must identify the resource adequacy and/or reliability need for which the project is being submitted. MISO also proposes to require that ERAS projects have a Commercial Operation Date within three calendar years from the submission date of the Interconnection Request. All ERAS projects are eligible to use the grace period of up to three years as documented in GIA Article 2.3.1. MISO's accepted queue reform filing[211] and proposed Order No. 2023 compliance[212] will help MISO facilitate the reduction of the DPP cycle to the approximate one year timeline by 2028, and ERAS projects will help address documented load growth need prior to reducing the DPP cycle timeline.[213]

4. GIP Section 3.4

MISO proposes to add clarifying language stating, "except for projects submitted through the ERAS process as noted in Section 3.9," to this section governing OASIS posting requirements to clarify that MISO intends to publish the list of projects submitted for ERAS on its public

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211 *See* Queue Reform Filing.

212 *Midcontinent Independent System Operator, Inc.*, Compliance Filing for Order Nos. 2023 and 2023-A, Docket No. ER24-2046-000 (May 16, 2024) ("Order 2023 Compliance Filing").

213 *See Midcontinent Indep. Sys. Operator, Inc.*, 178 FERC ¶ 61,141 (2021) ("Timeline Reduction Filing").

website. Although MISO does not publish identifying information for projects submitted to the DPP interconnection queue, MISO believes that ERAS projects require additional transparency for interested parties in the MISO region.

5. GIP Section 3.5

MISO proposes to revise GIP Section 3.5 to add a reference to newly created GIP Section 3.5.2, explained further below, and to clarify that coordination procedures for affected systems apply except as provided by "Sections 3.5.1 and 3.5.2" of the GIP. MISO proposes to revise GIP Section 3.5.1.1 subsection (1) to clarify that ERAS projects shall be included in a JTIQ Screening Group, along with projects in the generator interconnection queue. As discussed in prior stakeholder meetings, MISO intends to consider ERAS projects for JTIQ. This revision is necessary to ensure that ERAS projects are properly included in JTIQ Screening Groups along with projects from MISO's DPP interconnection queue.

MISO proposes to add Section 3.5.2 to incorporate the application of the Affected Systems Coordination Procedures to Interconnection Requests included in ERAS. The revisions will enable MISO to promptly provide any affected systems analysis received from the affected system to the ERAS Interconnection Customer. The revisions also explain that if the affected systems studies and cost information are not available at the time the EGIA is tendered, the EGIA will include an obligation to execute any agreements for the studies. The proposed revisions state that ERAS Interconnection Requests will be submitted to the applicable system study individually and on serial basis. Finally, the revisions require the queue priority date for ERAS projects as the date MISO starts the ERAS System Impact Study unless the controlling agreement between MISO and the affected system provides an alternate queue priority date for ERAS projects. These revisions are needed given that ERAS projects will be studied serially and that existing affected systems coordination rules geared towards multi-phase group studies cannot apply without adjustment. The proposed rule set ensures timely affected systems review using a process appropriate for the accelerated ERAS study process while still allowing needed flexibility for MISO and individual seems partners to make adjustments needed for the specific seam.

6. GIP Sections 3.9 and 3.9.1

MISO proposes to add new GIP Section 3.9 to encompass the necessary processes and implementation details for ERAS Interconnection Requests. Proposed Section 3.9.1 explains the requirements for submitting a project to ERAS, which include the requirements listed in GIP Section 3.3.1, as well as a written verification from a RERRA that states either (1) the new, incremental load addition claimed by the Interconnection Customer is valid and not already included in a plan or other procedure under the RERRA's purview, or (2) addresses a resource adequacy deficiency as determined by the RERRA, state, LSE, or Interconnection Customer and supported by evidence from a state energy forecast, state proceeding, resource plan, response to a request for proposals, or other state or RERRA process.

The revisions to Section 3.9.1.1(iii) also enable retail choice states (Illinois and Michigan) to participate in ERAS. The revisions allow an Interconnection Customer to participate if the new facility addresses a resource adequacy deficiency and will serve retail choice load. If the Interconnection Customer is serving retail choice load, it will not be required to include a verification from a RERRA in accordance with state policy, but MISO will notify the respective RERRA about the request and give that RERRA an opportunity to object to the ERAS application. The Interconnection Customer will also provide evidence of determination of need as described in Section 3.9.1.1(ii). MISO is proposing this language to enable retail choice state participation in ERAS and to reflect how RERRAs operate differently in the retail choice states.

The proposed RERRA language also clarifies that the RERRA verification is not intended to provide evidence of need or suitability of an ERAS project in a separate state or RERRA regulatory process. It is simply a requirement of the MISO ERAS application process that will allow projects to have completed study and be available without prejudicing the ability of the RERRA to make final permitting or certificating decisions according to their laws and regulations.

In the revisions to Section 3.9.1.2, MISO also proposes to require the Interconnection Customer provide an agreement showing that the project submitted to ERAS is intended to be used to meet a claimed resource adequacy and/or reliability need. The agreement may take several forms, as documented in Section 3.9.1, depending on the type of project and associated parties. This language is intended to limit ERAS projects to those needed to meet a resource adequacy and/or reliability need, while also ensuring that certain project types or submitters are not excluded from participating in ERAS.

As previously explained above, the language developed in Section 3.9.1 regarding the RERRA verification and the Interconnection Customer's requirement to provide an executed agreement showing that the project submitted will be used to meet the claimed resource adequacy and/or reliability need were discussed at length with stakeholders and the MISO states before MISO's original ERAS filing and were adjusted to address the Commission's guidance. These proposed revisions are intended to provide sufficient documentation displaying the need to be included in ERAS while also taking into consideration the varied processes of the states in MISO's footprint and the need for the ERAS process to fit within the different regulatory requirements of the MISO states. Because the majority of MISO states are vertically integrated, it is important to consider the states' involvement in resource adequacy as discussed in this letter.

Finally, MISO proposes to add language stating that no changes shall be made to the Interconnection Request after submission. Because the timeline from submission to an executed EGIA is 90 days, this language is necessary to ensure that ERAS projects are studied expeditiously and can be online as soon as possible to meet the stated resource adequacy and/or reliability need.

7. GIP Section 3.9.2

MISO proposes to add GIP Section 3.9.2 to facilitate the evaluation process of projects seeking to use ERAS.

> The Transmission Provider will evaluate Expedited Resource Addition Study requests in the order in which they are submitted using the time stamp from submission. The Transmission Provider will limit the maximum number of the ERAS Interconnection Requests studied in the ERAS process to no more than 68 projects total until the sunset date noted in Section 3.9.9. The Transmission Provider has carved out a maximum of 8 Interconnection Requests of the total 68 Interconnection Requests that may be submitted in accordance with 3.9.1.1(iii) to serve retail choice load and a maximum of 10 Interconnection Requests of the total 68 Interconnection Requests that may be submitted by Independent Power Producers (IPPs) with agreements with entities other than Load Serving Entities to ERAS until the sunset date noted in Section 3.9.9.
>
> The Transmission Provider will limit the maximum size of each ERAS Quarterly Study Period to no more than 10 Interconnection Requests. If more than 10 Interconnection Requests are submitted for one ERAS Quarterly Study Period, those surpassing the limit will be studied in a subsequent ERAS study cycle in the order in which they were submitted. If an ERAS Interconnection Request is within a similar geographical area or impacts the same constraint as another ERAS Interconnection Request within the same ERAS Quarterly Study Period, as defined in the Generator Interconnection Business Process Manuals, then the later submitted request(s) will be studied in a subsequent ERAS study cycle.

The revised language sets out how MISO plans to implement the ERAS project cap. MISO will limit the maximum number of the ERAS Interconnection Requests studied in the ERAS process to no more than 68 projects total until the ERAS sunset date noted in Section 3.9.9. MISO has determined two separate carve outs from the total 68 projects: (1) a maximum of 8 Interconnection Requests that may be submitted to serve retail choice load, and (2) a maximum of 10 Interconnection Requests that may be submitted by Independent Power Producers ("IPP"). The remaining 50 Interconnection Requests may be utilized by other Interconnection Customers in non-retail states.

The proposed language explains that MISO will also cap the number of projects studied in each ERAS study cycle. MISO will limit the maximize size of each ERAS Quarterly Study Period to no more than 10 Interconnection Requests. MISO will complete a screening process on the first 10 Interconnection Requests received per ERAS cycle to determine whether any of the projects are located in the same geographic area or impacting the same constraint. If two or more projects are located in the same geographic area or impact the same constraint as defined by MISO's Generator Interconnection Business Process Manuals, then the first project received as determined

by submission time will remain in the cycle and the other project(s) will be deferred to the next available ERAS cycle.

Other proposed language explains that projects will be evaluated in the order in which they are submitted. It also provides that a project that does not meet the ERAS requirements will be automatically moved to the generator interconnection queue unless the Interconnection Customer informs MISO that it does not want to be processed through the DPP if it fails to qualify for ERAS. Although the project moving from ERAS will be required to meet all requirements of the generator interconnection queue, the automatic transfer to the interconnection queue will prevent projects from having to resubmit an additional Interconnection Request and will provide a more efficient application process. Proposed language also clarifies that if the project is found to be ineligible for ERAS, the project will lose its Non-Refundable Deposit D1. The risk of losing a large deposit if determined to be ineligible for ERAS will encourage parties to only submit projects that they are certain will meet the strict ERAS requirements.

Proposed Section 3.9.2 also documents the process for projects currently in the generator interconnection queue to transfer to ERAS for evaluation. In the situation where a project in the generator interconnection queue is eligible to participate in ERAS and chooses to transfer to the ERAS process, proposed language also clarifies that the project will forfeit its Non-Refundable Deposit D1 and will be subject to withdrawal penalties per Sections 7.6.2.1.1 and 7.8. This proposed addition is necessary to ensure that projects dropping out of the generator interconnection queue do not harm remaining projects in their respective cycles. Similarly, proposed language in Section 3.9.2 limits projects from transferring from the generator interconnection queue to ERAS to only those that have not reached Decision Point II. This language is required to ensure that projects remaining in the generator interconnection queue are not harmed by restudies that occur after projects drop out after Decision Point II. If a project withdraws after Decision Point II, the proposed ERAS revisions will allow it to submit to ERAS after a period of one year from the withdrawal date. This language is necessary to prevent late stage withdrawals from the generator interconnection queue that might harm other projects in the interconnection queue cycle.

8. GIP Section 3.9.3

MISO proposes to add a new GIP Section 3.9.3 to describe the studies that will take place for ERAS projects, which mirror those performed for Interconnection Requests in the DPP seeking NRIS, as described noted in GIP Sections 3.2.1.2 and 3.2.2.2. MISO intends to perform all ERAS studies within 60 Days after kickoff to help ERAS projects quickly obtain an executed EGIA. ERAS projects will be evaluated on a rolling basis during each Quarterly Study Period The studies will be performed serially, based on submission date. serial studies are ideal for ERAS projects since there will be a considerably smaller number of proposed projects spread over a larger geographic area, thus they will not be grouped into clusters which would require late stage restudies.

Proposed language also explains that any Affected System Study results, if available, will be included at the time of the final ERAS study. If the Affected System Study results are unavailable at the time of the final study, those results will be provided separately when received from the applicable Affected System.

9. GIP Section 3.9.4

MISO proposes to add the following Section 3.9.4, which is titled Notice to Proceed to EGIA.

> Interconnection Customer requesting to be included in ERAS shall inform Transmission Provider of its election to proceed within five (5) Calendar Days after receiving the draft results of the Expedited Resource Additions Study. Interconnection Customer that fails to provide an election to proceed within five (5) Calendar Days will result in withdrawal of the Interconnection Request pursuant to Section 3.6 of this GIP. EGIA execution shall occur no later than 30 Calendar Days after receiving Interconnection Customer's election to proceed.

This language is necessary to distinguish between the shorter timeline for ERAS and the general timeline for providing a notice to proceed for a DPP interconnection project. The shortened five Calendar Day timeline is necessary to allow Customers to execute their EGIA within 90 days from kickoff of the Quarterly Study Period.

10. GIP Section 3.9.5

Proposed GIP Section 3.9.5 governs the timeline and necessary requirements regarding tender of the draft pro forma EGIA and JTIQ applicability, and also points to Sections 11.1 through 11.4 of the GIP governing procedures such as MISO's tender of the draft EGIA, negotiations, and execution of the EGIA. This proposed Section provides a five Business Day timeline for MISO to tender a draft *pro forma* EGIA after receiving notification of the Customer's intent to proceed to EGIA.

Due to the varied nature of MISO's and SPP's processes related to JTIQ Service Agreements, proposed revisions provide a path forward for JTIQ eligible ERAS projects if SPP's JTIQ Service Agreement has not been provided to the Interconnection Customer prior to the tender of the draft EGIA. If the SPP JTIQ Service Agreement has not been received at the time of MISO's tender of the EGIA, proposed language requires JTIQ eligible ERAS projects to include a milestone in GIA Appendix B requiring the parties to execute or request the unexecuted filing of an SPP JTIQ Service Agreement within 15 Calendar Days after such agreement has been tendered to the Interconnection Customer. Proposed language also states that ERAS Interconnection Requests included in a JTIQ Participation Group shall adhere to all JTIQ procedures and execute JTIQ Service Agreements as applicable.

11. GIP Sections 3.9.6, 3.9.6.1, 3.9.6.2, and 3.9.6.3

Proposed GIP Section 3.9.6 and its subparts document the process for obtaining refunds of study deposits and milestone payments in the ERAS process.

Proposed GIP Section 3.9.6.1 governs applicable refunds of the Study Deposit (D2). As with generator interconnection requests, ERAS D2 study deposit amounts are based on Megawatt amount of new interconnection service of the ERAS project as stated in GIP Section 3.3.1. The Interconnection Customer will be charged the actual amount of the Expedited Resource Addition Study and will be required to pay any additional costs or will be refunded any overages as applicable.

Proposed GIP Section 3.9.6.2 details the process for receiving a refund of the ERAS milestone payment M2. ERAS projects are eligible to receive a 100% refund of M2 upon withdrawal prior to execution of the EGIA. If an ERAS project withdraws after execution of the EGIA, the project is only eligible to receive a refund of any remaining M2 milestone after meeting the Initial Milestone Payment and/or Network Upgrade costs memorialized in the EGIA.

Should a project withdraw after execution of the EGIA, proposed Section 3.9.6.3 documents the process for providing the initial payment to the Transmission Owner, which will occur within forty-five Calendar Days from the effective date of the EGIA. If the M2 provided by the Interconnection Customer exceeds the initial payment amount, MISO will provide a refund of any remaining M2 within 45 Calendar Days of the effective date of the EGIA. If the Interconnection Customer's M2 is less than the initial payment, the proposed language of 3.9.6.3 requires the Interconnection Customer to provide the remaining portion of the initial payment to the Transmission Owner.

Proposed language in GIP Section 3.9.6.3 also clarifies that Interconnection Customers that withdraw after execution of the EGIA by all parties, or upon the filing of an unexecuted EGIA, will be liable for any Network Upgrade costs documented in the EGIA, including Network Upgrades arising from the Affected System Study process. This language is necessary to ensure that only viable projects that can meet the requirements of ERAS apply to participate in the ERAS process. In the event that a viable project must withdraw after execution of the EGIA, this language is necessary to ensure that no remaining projects are harmed by the withdrawal and Network Upgrades are built as planned.

12. GIP Section 3.9.7

MISO proposes to add new GIP Section 3.9.7, which is titled Transfer of Ownership of Expedited Resource Addition Study Request.

> An Interconnection Customer participating in the Expedited Resource Addition Study may transfer its Interconnection Request to another entity only after execution of the EGIA or filing the EGIA unexecuted. The new entity must maintain the eligibility requirements per Sections 3.3.1 and 3.9.1.

This language is necessary to prevent transfers prior to EGIA execution that might slow down the timeline for studying an ERAS project and ultimately delay the ability for MISO to move ERAS projects to EGIA execution within 90 days from kickoff. Prohibiting any changes to an ERAS project prior to EGIA execution will allow MISO to maintain its proposed ERAS timeline while allowing projects the flexibility to transfer the project to a new owner after EGIA execution. Similar to requirements for the generator interconnection queue, any transferee must maintain the applicable requirements to remain a valid ERAS project after EGIA execution.

13. GIP Section 3.9.8

MISO proposes to add new GIP Section 3.9.8, titled Modifications of Expedited Resource Addition Study Request.

> After entering the Expedited Resource Addition Study as defined in Section 3.9.3, no changes to the In-Service Date or Commercial Operation Date of the Generating Facility is permitted via Section 4.4.4. An ERAS Interconnection Request that is deferred to the next available ERAS Quarterly Study Period will be allowed to extend its In-Service Date or Commercial Operation Date to be no more than three calendar years from the kickoff of the ERAS Quarterly Study Period in which its application is studied. At the completion of the Expedited Resource Addition Study, the Commercial Operation Date and In-Service Date shall be set forth in the EGIA.

This language is necessary to ensure that ERAS projects are able to meet the resource adequacy and/or reliability need within the timeframe allotted by ERAS. The proposed ERAS COD requirements set forth in GIP Section 3.3.1 are specifically for generation needed to meet load intended to come online while ERAS is in place. Disallowing changes to the In-Service Date or COD after entering ERAS creates the certainty necessary to ensure that these projects will meet the need identified in the Interconnection Request and will prevent projects with uncertain timelines from entering ERAS.

14. GIP Section 3.9.9

MISO proposes to add new GIP Section 3.9.9, titled Sunset of Expedited Resource Addition Study Process.

> Following the effective date of the Tariff revisions accepted in Commission Docket No. ER25-____, the Transmission Provider will terminate the ERAS process at the earlier of the completion of sixty-eight ERAS Interconnection Request studies or August 31, 2027. In the event the Transmission Provider determines the sunset date should be extended, the Transmission Provider shall submit an additional filing to the Commission pursuant to Section 205 of the Federal Power Act seeking such later sunset date. Upon termination of ERAS, the Transmission Provider will no longer accept new ERAS Interconnection Requests. Any ERAS Interconnection Requests accepted but cannot be studied due to the sunset of the ERAS process will automatically move to the standard Definitive Planning Phase queue unless the customer chooses to withdraw. If deemed ineligible for the ERAS process, the project will forfeit its Non-Refundable Deposit D1.

This language is necessary to provide certainty that ERAS is a temporary process and that MISO intends to use ERAS for a limited period of time to meet generation shortages due to reasons explained above. ERAS will automatically sunset at the earlier of the completion of 68 ERAS Interconnection Request studies or August 31, 2027. The ERAS process is intended to fill the gap created by current queue backlogs and projects with GIAs yet to come online by providing expedited treatment for needed projects to be studied and come online quickly. As previously stated, the ERAS process is intended to be temporary and to fulfill the purpose of meeting generation needs during the short time period prior to the ERAS sunset date. MISO does not intend to request additional time for ERAS, but should MISO determine that additional time is needed to process ERAS projects to fill the aforementioned gap, MISO will submit an additional 205 filing and will justify the need for additional time.

15. GIP Section 5.13

MISO proposes to add new GIP Section 5.13, titled Transition to ERAS Process.

> All requests for the Expedited Resource Addition Study that are submitted to the Transmission Provider after August 6, 2025 will be subject to the revised Tariff requirements accepted in Docket No. ER25-___.

MISO proposes to begin the first ERAS Quarterly Study Period on September 2, 2025, which will be the first Quarterly Study Period after the effective date of these revisions, August 6, 2025.

16. GIP Section 7.2.1

MISO proposes to revise GIP Section 7.2.1, subpart (ii) to add the following language:

> Reasonable evidence of Site Control for one hundred percent (100%) of the mileage of the Generating Facility's Interconnection Facilities for the Expedited Resource Addition Study request must be received at the time the application is submitted. The financial security in lieu of Site Control for the Generating Facility's Interconnection Facilities will not be accepted for an Expedited Resource Addition Study request.

Increased Site Control requirements for the Generating Facility's Interconnection Facilities (in conjunction with the accepted increased Site Control requirements under 7.2.1[214]) will ensure that projects submitted to ERAS are "shovel ready" and able to quickly meet the needs of the load they seek to service. Current interconnection queue Site Control requirements only require 50% Site Control of the Interconnection Customer's Interconnection Facilities at the time of submission, so this increased Site Control requirement will encourage only ready projects to submit to the ERAS process. Similarly, disallowing financial security in lieu of Site Control will prohibit any projects from being eligible for ERAS if it is unable to obtain the proper permits or siting requirements. Both updates to Site Control requirements will ensure that only "shovel ready" projects apply and will allow ERAS projects to quickly move to EGIA execution.

17. GIP Section 7.3.1.4

MISO proposes to add a reference to ERAS projects in Section 7.3.1.4 to clarify that projects from the DPP and ERAS will be notified if included in a JTIQ Screening Group. Although not part of the DPP, ERAS projects may impact a JTIQ Upgrade and should be subject to the same rules as DPP projects with respect to JTIQ. ERAS projects will be eligible for inclusion in the JTIQ Screening Group, Participation Group, and Commitment Groups based on the same criteria

[214] *See* Queue Reform Filing at 10.

that are applied to DPP projects. This revision is necessary to ensure that ERAS projects are included in the JTIQ construct and do not get a free ride.[215]

18. GIP Section 7.3.2.3.1

MISO proposes to add "including ERAS projects not otherwise subject to Transmission Provider's three-phase DPP" in subpart 1, to clarify that ERAS projects that are part of a JTIQ Screening Group will be subject to additional Affected System analysis, as well as analysis required in Section 7.3.2.3 of the GIP. The additional analysis determines the impact of an ERAS project on the SPP system through Expanded Scope Analysis and Supplemental Affected System Analysis as documented in subparts a and b of this section and the inclusion of the aforementioned edits ensures that applicable ERAS projects will be studied similarly to DPP projects in these instances.

19. GIP Section 11.1

MISO proposes to revise Section 11.1 to include the distinction that ERAS projects will not contain restudies and that tender of the draft EGIA will occur after the Interconnection Facilities Study initiated through ERAS. MISO also proposes to revise this Section to clarify that ERAS Interconnection Requests tender of the EGIA will occur on a different timeline than DPP projects, which timeline for tender is memorialized in new GIP Section 3.9.5. These edits are necessary to properly document the shortened timeline for tender of ERAS projects and the differences in timing between ERAS projects with one study and DPP projects with multiple studies.

20. GIP Section 11.2 and 11.2.1

MISO proposes to revise Section 11.2 to clarify that ERAS projects will have a shorter, 5 Business Day timeline to return comments on the draft EGIA. MISO also proposes to revise this Section to clarify that MISO shall tender a revised draft EGIA after 5 Business Days of receiving the comments. For ERAS projects, negotiations of EGIAS shall be no more than 20 Business Days from the notice to proceed in Section 3.9.4. Revisions to 11.2.1 clarify that ERAS projects are unable to postpone the start of the EGIA negotiation period.

These edits are needed to shorten the negotiations timeframe to keep the ERAS process to approximately 90 days from kickoff to EGIA execution. This shortened timeframe will ensure that ERAS projects are able to execute the EGIA quickly and come online within the timeframe allotted to serve the project's identified need.

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[215] MISO notes that it will be necessary to update some language in its Joint Operating Agreement with the Southwest Power Pool, Tariff Rate Schedule 6 ("SPP JOA"), which, for MISO, discussed JTIQ only in terms of DPP projects. This language reflects the fact that ERAS did not exist at the time. MISO has discussed updating the JOA with SPP and plans to make a joint filing to properly references ERAS before the requested effective date for this filing.

21. GIP Section 11.3

MISO proposes to revise Section 11.3 to provide that for ERAS projects the Transmission Provider shall provide the Interconnection Customer and Transmission Owner a final EGIA within 10 Business Days after completion of the negotiation period in accordance with Section 11.2. These revisions also provide that the parties must execute the EGIA or request to file unexecuted within 10 Business Days of tender of the final EGIA, otherwise the project will be deemed to have withdrawn its Interconnection Request. These revisions are required to properly document the shorter timeline for ERAS projects as compared to the timeline for DPP GIA execution as memorialized in this Section.

B. Attachment X, Appendix 6, Generator Interconnection Agreement

a. Article 1 Definitions

MISO proposes to revise Article 1 to include ERAS-related definitions consistent with the GIP, as applicable, and to provide updates to JTIQ-related definitions to clarify that MISO ERAS and SPP ERAS projects will be included in JTIQ, also as provided in the GIP.

b. Article 2.3.3

MISO proposes to revise Article 2.3.3 to state that ERAS projects must provide all security required in Section 2.4 prior to any termination request for an ERAS project becoming effective. This language is necessary to ensure that projects are held liable for any Network Upgrades that would be memorialized in an EGIA or related agreement and to prevent harm to other projects due to the withdrawal.

c. Article 2.4

MISO proposes to revise Article 2.4 to specify that should an ERAS project terminate, it will be liable for any Network Upgrade costs identified in the EGIA or that would be memorialized in an FCA, MPFCA, or JTIQ Service Agreement. If the final costs have not been determined, the Customer must provide security according to the most recent estimate. Additionally, the Transmission Provider will provide any applicable refunds of payments or security within 90 Calendar Days of providing the final invoice of NUs to the Customer. As stated above, the proposed language is necessary to ensure that only "shovel ready" projects submit to ERAS, knowing those projects will assume the risk of paying for any Network Upgrades identified in an EGIA or that would be memorialized in an FCA, MPFCA, or JTIQ Service Agreement. This language will ensure that no other projects are affected by the termination.

d. Appendix B Milestones

MISO proposes to add new milestone 1f to the *pro forma* Generator Interconnection Agreement:

1f.	Enter into any agreement required by an Affected System for the study, construction, or funding of a network upgrade to mitigate impacts (for Interconnection Requests processed through ERAS) pursuant to GIP Section 3.5.2.	Within 15 Calendar Days after tender.

This revision is needed to ensure that ERAS interconnection requests are subject to the same obligations as other Interconnection Requests with respect to network upgrades identified by affected systems. The requirement to execute an agreement with the affected system to mitigate any impacts from the ERAS Interconnection Request within 15 days after agreement tender is included in proposed GIP Section 3.5.2. It is appropriate to reflect this commitment in a GIA milestone given that, due to the accelerated timing of ERASs, an affected system may first be able to tender their form of agreement after the ERAS Interconnection Customer already has executed their GIA. Including milestone 1f in Appendix B ensures that this obligation remains enforceable even after the customer has an effective GIA. This puts ERAS Interconnection Customers on the same footing as DPP Interconnection Customers.

C. Attachment X, Appendix 1, Interconnection Request for a Generating Facility

MISO proposes to revise Attachment X, Appendix 1 to add a check box in Section 2 indicating that the interconnection Request is being submitted as an ERAS project.

MISO also proposes to add subpart s to Section 4, stating that at the time of application to ERAS, the Interconnection Customer must provide information about the resource adequacy and/or reliability need that the ERAS project is intended to address. These proposed revisions are needed to properly memorialize the requirements to be included in ERAS, which includes the Interconnection Customer identifying resource adequacy and/or reliability need the project claims to meet. The ERAS process is intended to facilitate matching generation with load within the next few years, so requiring a specific need will prevent projects from submitting to ERAS simply to circumvent the generator interconnection queue process. This proposed language will ensure that ERAS projects are limited to those that truly identify a claimed resource adequacy and/or reliability need.

V. DOCUMENTS SUBMITTED WITH THIS FILING

In addition to this Transmittal Letter, the documents submitted with this filing are:

Tab A – Redlined Tariff Sheets[216];

Tab B – Clean Tariff Sheets; and

Tab C – Prepared Direct Testimony of Andrew Witmeier

VI. PROPOSED EFFECTIVE DATE, AND REQUEST FOR EXPEDITED ACTION AND SHORTENED COMMENT PERIOD

MISO requests that the proposed Tariff revisions be made effective on August 6, 2025. To give certainty to stakeholders and allow them time to prepare Interconnection Requests in advance of the first ERAS deadline, MISO respectfully requests the Commission issue an order on an expedited basis by July 22, 2025. MISO needs to address the looming resource adequacy and reliability needs identified in this filing as expeditiously as possible and stakeholders will need to know if the process has been accepted sufficiently in advance of the deadline to plan their projects. Thus, MISO can accommodate the ordinary 60 day timeframe for revisions becoming effective and need not seek waiver for a shortened effective date provided that an order is issued within 45 days. The original ERAS proposal was discussed extensively with stakeholders and the main refinements made to that proposal were addressed in the May PAC Meeting and tailored to the Commission's guidance issued on May 16, 2025.

To enable the Commission's consideration of this filing, MISO also requests that the Commission establish a ten (10) day comment period for this filing – June 16, 2025. As noted above, this filing represents a refinement to MISO's original ERAS proposal and all affected parties have had ample notice of that filing and the Commission's guidance responded to in this submission. This effective date will ensure that the proposed changes can be implemented in advance of the September 2, 2025 ERAS Quarterly Study Period start date.

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[216] Language currently pending before the Commission in the following, unrelated docket is highlighted in yellow: Docket No. ER25-2417-000. MISO requests that the Commission treat such highlighted language as subject to the outcome of the pending proceeding. MISO commits to file any revisions to this highlighted language as necessary to comply with any Commission order in the proceeding. MISO has removed language that has a future effective date of June 1, 2029 and is pending under Docket No. ER22-1640-006. In addition, MISO has removed pending language filed in Docket No. ER24-2046-000, and any changes will be based on the outcome of that docket. If needed, MISO commits to make a subsequent filing with the Commission to reflect the most up-to-date version of the then-current Tariff provisions prior to the effective dates of the language in Docket Nos. ER22-1640-006 and ER24-2046-000.

MISO submits that the requirements of Section 35.13 of the Commission's regulations, 18 C.F.R. § 35.13 (2024), that have not been specifically addressed herein are inapplicable to this filing. To the extent that the Commission determines any of these sections to be applicable to this filing, MISO respectfully requests waiver of the requirements of such sections.

VII. COMMUNICATIONS, NOTICE, AND SERVICE

Correspondence and communication with respect to this filing should be sent to the following individuals, which MISO requests to also be included on the official service list:

Sarah Nieman*
Christopher D. Supino*
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Carmel, IN 46032
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*Persons authorized to receive service

MISO notes that it has served a copy of this filing electronically, including attachments, upon all Tariff Customers under the Tariff, MISO Members, Member representatives of Transmission Owners and Non-Transmission Owners, as well as all state commissions within the Region. The filing has been posted electronically on MISO's website at https://www.misoenergy.org/legal/ferc-filings/ for other interested parties in this matter. In addition, MISO has served a copy of this filing electronically on all parties to this agreement.

IX. CONCLUSION

MISO's proposed ERAS reforms are just and reasonable, are not unduly discriminatory or preferential, and thus satisfy the requirements of FPA section 205(a). For all of the foregoing reasons, MISO respectfully requests that the Commission: (1) accept this filing with the August 6, 2025 effective date; (2) issue an order by July 22, 2025, and (3) grant waiver of any Commission regulations that the Commission may deem applicable to this filing.

Respectfully submitted,

/s/ Sarah Nieman

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Attachments

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-7

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

Filed September 5, 2025

Exhibit 91

MISO ERAS Decision

192 FERC ¶ 61,064
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Mark C. Christie, Chairman;
David Rosner, Lindsay S. See,
and Judy W. Chang.

Midcontinent Independent System Operator, Inc. Docket No. ER25-2454-000

ORDER ACCEPTING TARIFF REVISIONS, SUBJECT TO CONDITION

(Issued July 21, 2025)

1. On June 6, 2025, Midcontinent Independent System Operator, Inc. (MISO) submitted, pursuant to section 205 of the Federal Power Act (FPA)[1] and part 35 of the Commission's regulations,[2] proposed revisions to Attachment X in the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff), which contains MISO's Generator Interconnection Procedures (GIP), to establish the Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term.[3] In this order, we accept MISO's proposed Tariff revisions, subject to condition, effective August 6, 2025, as requested, as discussed below.

I. Background

2. In Order No. 2003,[4] the Commission required public utilities that own, control, or operate transmission facilities to file standard generator interconnection procedures and a standard agreement to provide interconnection service to generating facilities with a

[1] 16 U.S.C. § 824d.

[2] 18 C.F.R. pt. 35 (2024).

[3] MISO, FERC Electric Tariff, attach. X (Generator Interconnection Procedures (GIP)) (175.0.0); *id*. app. 1 (Interconnection Request for a Generating Facility)) (57.0.0); *id*. app. 6 (Generator Interconnection Agreement (GIA)) (108.0.0) (Proposed Tariff).

[4] *Standardization of Generator Interconnection Agreements & Procs.*, Order No. 2003, 104 FERC ¶ 61,103 (2003), *order on reh'g*, Order No. 2003-A, 106 FERC ¶ 61,220, *order on reh'g*, Order No. 2003-B, 109 FERC ¶ 61,287 (2004), *order on reh'g*, Order No. 2003-C, 111 FERC ¶ 61,401 (2005), *aff'd sub nom. Nat'l Ass'n of Regul. Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007).

capacity greater than 20 megawatts (MW). To this end, the Commission adopted the *pro forma* Large Generator Interconnection Procedures (LGIP) and *pro forma* Large Generator Interconnection Agreement (LGIA) and required all public utilities subject to Order No. 2003 to modify their tariffs to incorporate the *pro forma* LGIP and *pro forma* LGIA.[5]

3. The Commission permitted transmission providers to seek variations from the *pro forma* LGIP and *pro forma* LGIA if those variations were "consistent with or superior to" the terms of the *pro forma* LGIP and *pro forma* LGIA.[6] In addition, the Commission indicated that it would allow regional transmission organizations and independent system operators (RTO/ISO), such as MISO, to propose independent entity variations for pricing and non-pricing provisions, stating that RTOs/ISOs have different operating characteristics due to their sizes and locations and that an RTO/ISO is less likely to act in an unduly discriminatory manner than a transmission provider that is also a market participant.[7] The Commission found that RTOs/ISOs "shall therefore have greater flexibility to customize [their] interconnection procedures and agreements to fit regional needs."[8] Under the independent entity variation standard, an RTO/ISO must demonstrate that proposed deviations from the Commission's *pro forma* LGIP and *pro forma* LGIA are just and reasonable and not unduly discriminatory or preferential and accomplish the purposes of Order No. 2003.[9]

A. Overview of MISO's Generator Interconnection Process

4. Since the issuance of Order No. 2003, MISO has submitted several generator interconnection queue reform proposals. As relevant here, in January 2017, the Commission accepted MISO's proposal to implement a three-phase Definitive Planning

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[5] Order No. 2003, 104 FERC ¶ 61,103 at PP 1-2.

[6] *Id.* PP 825-826. The Commission also permitted transmission providers to justify a variation from the *pro forma* LGIP or *pro forma* LGIA based on regional reliability requirements and required transmission providers to submit these regional reliability variations to the Commission for approval under the relevant reliability standard. *Id.* PP 824, 826.

[7] *Id.* P 827.

[8] *Id.*

[9] *See, e.g.*, *Midcontinent Indep. Sys. Operator, Inc.*, 185 FERC ¶ 61,084, at P 11 (2023) (citing Order No. 2003, 104 FERC ¶ 61,103 at PP 26, 827).

Phase (DPP) process to study interconnection requests in clusters.[10] The DPP is based on a sequential review process that facilitates the structured study and restudy of proposed generating facilities.

5. Under the current procedures, MISO conducts one system impact study in each of the three DPP phases (i.e., a preliminary system impact study in DPP Phase I, a revised system impact study in DPP Phase II, and a final system impact study in DPP Phase III) to account for withdrawn interconnection requests and to refine and update the analysis.[11] During DPP Phases II and III, MISO also conducts a facilities study.[12] DPP Phases I and II are followed by interconnection customer decision points (Decision Point I follows DPP Phase I, and Decision Point II follows DPP Phase II).[13] The decision points provide interconnection customers opportunities to evaluate study results and decide whether to proceed with or withdraw their interconnection requests. On June 26, 2025, the Commission accepted in part MISO's Order No. 2023[14] compliance filing, which maintained its DPP process as an independent entity variation.[15]

6. On January 19, 2024, the Commission issued an order rejecting MISO's proposed revisions to its GIP to implement a cap on the total MW value of interconnection requests that may be studied in a cluster, as well as exemptions to that cap (2023 MISO Queue Cap Proposal).[16] The Commission found, among other things, that "the proposal to include cap exemptions has not been shown to be consistent with the Commission's open

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[10] *Midcontinent Indep. Sys. Operator, Inc*., 158 FERC ¶ 61,003, *order on reh'g*, 161 FERC ¶ 61,137 (2017).

[11] MISO, Tariff, attach. X (GIP) (171.0.0), §§ 7 (Definitive Planning Phase), 7.3.1 (Definitive Planning Phase I), 7.3.2 (Definitive Planning Phase II), 7.3.3 (Definitive Planning Phase III).

[12] *Id.* §§ 7 (Definitive Planning Phase), 7.3.2 (Definitive Planning Phase II), 7.3.3 (Definitive Planning Phase III).

[13] *Id.* §§ 7 (Definitive Planning Phase), 7.3.1.4 (Interconnection Customer Decision Point I), 7.3.2.4 (Interconnection Customer Decision Point II).

[14] *Improvements to Generator Interconnection Procs. & Agreements*, Order No. 2023, 184 FERC ¶ 61,054, *order on reh'g*, 185 FERC ¶ 61,063 (2023), *order on reh'g*, Order No. 2023-A, 186 FERC ¶ 61,199, *errata notice*, 188 FERC ¶ 61,134 (2024).

[15] *Midcontinent Indep. Sys. Operator, Inc*., 191 FERC ¶ 61,229 (2025).

[16] *Midcontinent Indep. Sys. Operator, Inc*., 186 FERC ¶ 61,054 (January 2024 Order), *order on reh'g*, 187 FERC ¶ 61,031 (2024).

access requirements"[17] because, despite the purpose of the cap being to limit the total MW studied in a queue cycle, exempted interconnection requests could enter the cycle regardless of the cap value (i.e., there was no limit to the number of exempted interconnection requests), and thus "the cap exemptions create[d] priority access to the generator interconnection process for the exempted classes of interconnection requests."[18] The Commission further stated that it had "concerns that specific exemptions have not otherwise been shown to be just and reasonable and not unduly discriminatory."[19] As an example, the Commission stated that MISO's proposal lacked "sufficient basis to conclude that the RERRA exemption will be limited to interconnection requests needed to meet state resource adequacy or reliability requirements."[20] The January 2024 Order also accepted MISO's proposed revisions to its GIP, in Docket No. ER24-340-000, to increase milestone payments, adopt an automatic withdrawal penalty, revise certain withdrawal penalty provisions, and expand site control requirements for interconnection facilities (2023 Non-Cap Queue Reform Proposal).[21]

7. On November 21, 2024, in Docket No. ER25-507-000, MISO submitted another proposal to establish a queue cap (2024 MISO Queue Cap), which the Commission accepted on January 30, 2025.[22] Unlike the 2023 MISO Queue Cap Proposal, the 2024 MISO Queue Cap established a hard limit on the total MW that could be studied in a cluster. While the 2024 MISO Queue Cap allowed for exemptions, such exemptions counted toward the hard cap limit, and the Commission determined that the proposed exemptions did not create open access concerns.[23] Unlike the 2023 MISO Queue Cap Proposal, the 2024 MISO Queue Cap did not include a RERRA exemption.

B. Initial ERAS Proposal and May 2025 Order

8. On March 17, 2025, in Docket No. ER25-1674-000, MISO submitted proposed revisions to its GIP to establish an ERAS process to provide a framework for the

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[17] *Id.* P 170.

[18] *Id.* P 176.

[19] *Id.* P 178.

[20] *Id.* P 177 n.413.

[21] January 2024 Order, 186 FERC ¶ 61,054 at P 1.

[22] *Midcontinent Indep. Sys. Operator, Inc.*, 190 FERC ¶ 61,057 (2025) (January 2025 Order).

[23] *Id.* P 87.

expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term (Initial ERAS Proposal). On May 16, 2025, the Commission issued an order rejecting the Initial ERAS Proposal.[24]

9. In the Initial ERAS Proposal, MISO proposed to create a quarterly "first-come, first-served" serial study process to facilitate the rapid study of interconnection requests for generating resources that are committed to addressing specific, identified resource adequacy and/or reliability needs,[25] resulting in an Expedited Generator Interconnection Agreement (EGIA) within approximately 90 days of study kickoff. MISO proposed that an ERAS interconnection request must request Network Resource Interconnection Service (NRIS).[26] MISO further proposed that an ERAS interconnection request must demonstrate that it is required to meet an identified resource adequacy and/or reliability need by providing both: (1) a written notification from the RERRA, or its documented representative, where the load to be served by the generating facility is located, that certifies or determines that the generating facility should be considered for the ERAS process in order to meet a resource adequacy and/or a reliability need claimed by the RERRA, the Load Serving Entity (LSE), or the interconnection customer; and (2) an executed agreement evidencing that the ERAS project is intended to be used by the entity with the claimed resource adequacy or reliability need.[27]

10. MISO's Initial ERAS Proposal also included certain requirements and obligations for ERAS interconnection requests that would not apply to other interconnection requests, including commercial operation date requirements, greater site control requirements, a greater application fee and milestone payments, and a requirement to pay for all network upgrades documented in the EGIA, even if the interconnection customer withdrew its request after the EGIA was executed or filed unexecuted with the Commission.[28]

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[24] *Midcontinent Indep. Sys. Operator, Inc.*, 191 FERC ¶ 61,131 (2025) (May 2025 Order).

[25] *Id.* P 8.

[26] MISO's GIP defines NRIS, in relevant part, as "an Interconnection Service that allows Interconnection Customer to integrate its Generating Facility with the Transmission System in the same manner as for any Generating Facility being designated as a Network Resource. [NRIS] does not convey transmission service." MISO, Tariff, attach. X (GIP) (171.0.0), § 1 (Definitions).

[27] May 2025 Order, 191 FERC ¶ 61,131 at P 9.

[28] *Id.* P 10.

11. In the May 2025 Order, the Commission rejected MISO's Initial ERAS Proposal, finding that MISO had not shown the proposal to be just and reasonable and not unduly discriminatory or preferential.[29] The Commission agreed with MISO that ensuring reliability and resource adequacy is of critical importance. The Commission explained, however, that the Initial ERAS Proposal placed no limit on the number of projects that could be entered in the ERAS process, which could result in an ERAS queue with processing times for interconnection requests that are too lengthy to meet MISO's stated resource adequacy and reliability needs, similar to the challenges with the current DPP queue. The Commission also found that MISO had not demonstrated that the Initial ERAS Proposal will solve the identified reliability and resource adequacy needs.[30]

12. The Commission further stated that MISO's proposal to provide 14 opportunities to enter the ERAS process through 2028, "could further impede MISO's ability to process ERAS requests on an expedited basis," and would "exacerbate[] the potential for a volume of ERAS interconnection requests untethered to reliability or resource adequacy needs."[31] The Commission stated that this aspect of MISO's Initial ERAS Proposal made it difficult to determine whether the solution was narrowly tailored enough to fix the problem.

13. In addition, the Commission stated that MISO did not adequately describe how the ERAS process was sufficiently targeted to study only interconnection requests needed to meet the anticipated shortfall in generating capacity described by MISO.[32] The Commission further stated that MISO had not demonstrated that the proposed Tariff language was tailored to ensure that only those resources capable of addressing identified near-term resource adequacy or reliability needs would be eligible for expedited study through the ERAS process.[33]

II. MISO's Filing

14. MISO explains that it is facing urgent near-term resource adequacy and reliability concerns due to load growth, generation retirement, and delays in the interconnection

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[29] *Id.* P 197.

[30] *Id.* PP 199, 201.

[31] *Id.*

[32] *Id.* P 201.

[33] *Id.* P 202.

process[34] and that it will experience a 4.7 gigawatt (GW) shortfall by 2028 if currently planned generating facility retirements occur.[35] MISO asserts that, while it has undertaken reforms to improve queue processing, the current processing presents a barrier to developing generation that can address these near-term needs. Therefore, MISO proposes revisions to its GIP and *pro forma* Generator Interconnection Agreement (GIA) to establish a revised ERAS process, which provides for accelerated study of interconnection requests that will address urgent resource adequacy and reliability needs in the near term (i.e., within the next five years) (Revised ERAS Proposal).[36] Specifically, under the Revised ERAS Proposal, MISO proposes to create a quarterly "first-come, first-served" serial study process to facilitate the rapid study of interconnection requests for generating resources that are committed to addressing specific, identified resource adequacy and/or reliability needs,[37] resulting in an EGIA within approximately 90 days of study kickoff.

15. MISO proposes to maintain that an ERAS interconnection request must meet capacity resource requirements and therefore must request NRIS.[38] Further, MISO proposes that an ERAS interconnection request must demonstrate that it is required to meet an identified resource adequacy and/or reliability need by providing both: (1) a written verification from the RERRA, or its documented representative, where the load to be served by the generating facility is located, that determines that the generating facility

[34] Transmittal at 5.

[35] *Id.* at 6 (citing *NERC's 2024 Long-Term Reliability Assessment* (published December 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf).

[36] *Id.* at 1. *See* MISO, Proposed Tariff, attach. X (GIP) (175.0.0), §§ 1 (Definitions), 2.1 (Application of Generator Interconnection Procedures), 3.3.1 (Initiating an Interconnection Request), 3.4 (OASIS Posting), 3.9 (Expedited Resource Addition Study), 5.13 (Transition to ERAS Process), 7.2.1 (Requirements for Demonstrating Site Control for Generating Facility), 7.3.1.4 (Interconnection Decision Point I), 7.3.2.3.1 (Additional Analysis Applicable to Interconnection Requests in a JTIQ Screening Group), 11.1 (Tender), 11.2 (Negotiation), 11.2.1 (Optional negotiation period adjustment for Interconnection Facilities Study), and 11.3 (Execution and Filing); *id.* app. 1 (Interconnection Request for a Generating Facility) (56.0.0); *id.* app. 6 (GIA) (106.0.0), art. 1 (Definitions), 2.3.3, and 2.4 (Termination Costs).

[37] Transmittal at 4; Filing, Tab C (Testimony of Andrew Witmeier) at 51-52 (Witmeier Testimony).

[38] Transmittal at 36-37.

should be considered for the ERAS process in order to meet a resource adequacy and/or a reliability need that is not otherwise included in a resource plan, is claimed by the RERRA, or serves load in a retail choice state; and (2) an executed agreement evidencing that the ERAS project is intended to be used by the entity with the claimed resource adequacy or reliability need.[39]

16. MISO's proposal also maintains certain requirements and obligations on ERAS interconnection requests that would not apply to other interconnection requests, including commercial operation date requirements, greater site control requirements, a greater application fee and greater milestone payments, and a requirement to pay for all network upgrades documented in the EGIA, even if the interconnection customer withdraws its request after the EGIA is executed or filed unexecuted with the Commission.[40] MISO also states that the Revised ERAS Proposal contains new requirements for ERAS interconnection requests to better demonstrate the connection between a proposed generating facility and an identified resource adequacy and/or reliability need. MISO proposes to establish a cap of 68 interconnection requests that may be studied under ERAS. MISO proposes that of the 68 ERAS interconnection requests, 10 interconnection requests are carved out for independent power producers that have agreements with entities other than LSEs and eight interconnection requests are carved out for those serving retail choice loads. These requirements are described in more detail below in part IV of this order.

17. MISO requests an effective date of August 6, 2025 to ensure that the ERAS process will be in place prior to September 2, 2025, when MISO plans to start its first ERAS quarterly study period. MISO states that ERAS is meant as a short-term solution for a near-term problem, and it has written into its proposed Tariff revisions a sunset date of August 31, 2027, or the completion date of the sixty-eighth ERAS interconnection request study, whichever occurs first.[41] MISO states that it envisions ERAS as a temporary process needed until MISO is able to reduce the DPP study timeline to one year.[42]

III. Notice and Responsive Pleadings

18. Notice of the filing was published in the *Federal Register*, 90 Fed. Reg. 25042 (June 13, 2025), with interventions and protests due on or before June 16, 2025. Clean

[39] *Id.* at 9, 27-30, 51-52.

[40] *Id.* at 56.

[41] *Id.* at 38-39; MISO, Proposed Tariff, attach. X (GIP) (175.0.0), § 3.9.9.

[42] Transmittal at 47.

Grid Alliance, Indicated Independent Power Producers (Indicated IPP),[43] NextEra, Public Interest Organizations (PIO),[44] and Trade Associations[45] each submitted a motion opposing the comment period of 10 days and requesting that the comment period be extended to 21 days. On June 11, 2025, the Office of the Secretary issued a notice denying the motions for extension of time.

19. Notices of intervention were filed by: the Minnesota Public Utilities Commission (Minnesota Commission); Organization of MISO States, Inc. (OMS); and the Public Utility Commission of Texas (Texas Commission).

20. Notices of intervention and comments were filed by: the Arkansas Public Service Commission (Arkansas Commission); the Illinois Commerce Commission (Illinois Commission); the Louisiana Public Service Commission and the Mississippi Public Service Commission (Louisiana and Mississippi Commissions); and the Missouri Public Service Commission (Missouri Commission).

21. A notice of intervention and limited protest was filed by the Michigan Public Service Commission (Michigan Commission).

22. Timely motions to intervene were filed by: Advanced Energy United; Alliant Energy Corporate Services, Inc. (AECS); American Clean Power Association and Clean Grid Alliance (jointly); Ameren Services Company, on behalf of Ameren Illinois Company d/b/a Ameren Illinois, Ameren Transmission Company of Illinois, and Union Electric Company d/b/a Ameren Missouri (collectively, Ameren); American Electric Power Service Corporation (AEP), on behalf of its affiliates AEP Energy Partners, Inc., AEP Indiana Michigan Transmission Company, Inc., and AEP Retail Energy Partners LLC; American Municipal Power, Inc.; Arevon; Big Rivers Electric Corporation (Big Rivers Electric); Calpine Corporation; Clean Energy Buyers Association; Clean Wisconsin; Clearway; Cleco Power LLC (Cleco); Coalition of Midwest Power Producers, Inc. (COMPP); Coalition of MISO Transmission Customers; Constellation

[43] Indicated IPPs include: Arevon Energy, Inc. (Arevon); Clearway Energy Group LLC (Clearway); Cordelio Power LP (Cordelio); EDF Renewables, Inc. (EDF); Invenergy LLC; NextEra Energy Resources, LLC (NextEra); and Pine Gate Renewables, LLC (Pine Gate).

[44] For purposes of the motion opposing the 10-day comment period, PIOs include: Clean Wisconsin; Fresh Energy; Natural Resources Defense Council; Sierra Club; and Sustainable FERC Project.

[45] Trade Associations include: American Clean Power Association; Clean Grid Alliance; Electric Power Supply Association (EPSA); Solar Energy Industries Association (SEIA); and Southern Renewable Energy Association.

Energy Generation, LLC (Constellation); Consumers Energy Company (Consumers Energy); Cooperative Energy; Cordelio; DTE Electric Company (DTE Electric); Duke Energy Indiana, LLC (Duke Energy Indiana);[46] Earthrise MISO Companies;[47] East Texas Electric Cooperative, Inc.; EDF; EPSA; Enel Green Power North America, Inc. (Enel); Entergy Services, LLC (Entergy), on behalf of the Entergy Operating Companies;[48] Eolian, LP; Fresh Energy; Indiana Office of Utility Consumer Counselor; International Transmission Company d/b/a ITC*Transmission* (ITC*Transmission*); Invenergy Renewables, LLC (Invenergy); Large Public Power Council; Midwest TDUs;[49] MISO Transmission Owners (MISO TOs);[50] MN8 Energy LLC (MN8); New Leaf Energy, Inc. (New Leaf); NextEra; Northern Indiana Public Service Company LLC (NIPSCO); Ørsted Wind Power North America LLC; Otter Tail; Pine Gate; Public Citizen, Inc.; RWE Clean

[46] Duke Energy Business Services LLC intervened on behalf of its affiliate Duke Energy Indiana.

[47] Earthrise MISO Companies include: Gibson City Energy Center, LLC; Shelby County Energy Center, LLC; and Tilton Energy LLC.

[48] The Entergy Operating Companies include: Entergy Arkansas, LLC; Entergy Louisiana, LLC; Entergy Mississippi, LLC; Entergy New Orleans, LLC; and Entergy Texas, Inc.

[49] Midwest TDUs include: Indiana Municipal Power Agency; The Missouri Joint Municipal Electric Utility Commission d/b/a the Missouri Electric Commission; Missouri River Energy Services; and WPPI Energy.

[50] For purposes of this filing, MISO TOs include: Ameren; American Transmission Company LLC; Big Rivers Electric; Central Minnesota Municipal Power Agency; Citizens Electric Corporation; City Water, Light & Power (Springfield, IL); Cleco; Cooperative Energy; Dairyland Power Cooperative; Duke Energy Business Services LLC for Duke Energy Indiana; East Texas Electric Cooperative, Inc.; Entergy Operating Companies; Great River Energy; GridLiance Heartland LLC; Hoosier Energy Rural Electric Cooperative, Inc.; Indiana Municipal Power Agency; Indianapolis Power & Light Company d/b/a AES Indiana; ITC*Transmission*; ITC Midwest LLC; Lafayette Utilities System; Michigan Electric Transmission Company, LLC (METC); MidAmerican Energy Company; Minnesota Power (and its subsidiary Superior Water, L&P); Montana-Dakota Utilities Co.; NIPSCO; Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation, subsidiaries of Xcel Energy Inc.; Northwestern Wisconsin Electric Company; Otter Tail Power Company (Otter Tail); Prairie Power, Inc.; Southern Illinois Power Cooperative; CenterPoint; Southern Minnesota Municipal Power Agency; Wabash Valley Power Association, Inc.; and Wolverine Power Supply Cooperative, Inc.

Energy, LLC; SEIA; Shell Energy North America (US), L.P.; Sierra Club; Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South (CenterPoint); Southern Renewable Energy Association; Southwest Power Pool, Inc. (SPP); Sustainable FERC Project and Natural Resources Defense Council (jointly); Treaty Oak Clean Energy, LLC; Union of Concerned Scientists; Vistra Corp. (Vistra); and Wisconsin Utilities.[51]

23. Timely comments were filed by: AECS; Ameren; Big Rivers Electric; CenterPoint; Consumers Energy; DTE Electric; Duke Energy Indiana; Entergy, Cleco, and Cooperative Energy (collectively, Entergy/Cleco/Cooperative Energy); EPSA; Indiana Energy Association;[52] ITC*Transmission*, METC, and ITC Midwest LLC (collectively, ITC); Midwest TDUs; MISO TOs; NIPSCO; Otter Tail; and Wisconsin Utilities.

24. Individual comments were filed by: Governor Mike Braun (Indiana Governor); Governor Mike Kehoe (Missouri Governor); Governor Jeff Landry (Louisiana Governor); Governor Tate Reeves (Mississippi Governor); Robert E. Rutkowski; and Governor Sarah Huckabee Sanders (Arkansas Governor).

25. Timely protests were filed by: Clean Energy Associations;[53] Clean Grid Alliance; COMPP; Constellation; Invenergy; MISO Independent Power Producers (MISO IPP);[54] PIOs;[55] and Vistra.

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[51] Wisconsin Utilities include: Wisconsin Electric Power Company; Wisconsin Public Service Corporation; and Upper Michigan Energy Resources Corporation.

[52] Indiana Energy Association filed comments on behalf of AES Indiana, CenterPoint Energy Indiana, Duke Energy Indiana, and NIPSCO.

[53] Clean Energy Associations include: Advanced Energy United; American Clean Power Association; Clean Grid Alliance; SEIA; and Southern Renewable Energy Association.

[54] MISO IPPs include: Arevon; Clearway; Cordelio; EDF; EDP Renewables North America, LLC; Enel; Invenergy LLC; MN8; New Leaf; NextEra; and Pine Gate.

[55] For purposes of the protest, PIOs include: Clean Wisconsin, Fresh Energy, Sierra Club, Sustainable FERC Project, and Union of Concerned Scientists.

26. On June 20, 2025, MISO filed a motion for leave to answer and answer (MISO Answer).[56] On June 26, 2025, MISO IPPs submitted an answer to the MISO Answer. On June 27, 2025, Clean Energy Associations and Clean Grid Alliance each submitted answers to the MISO Answer.

27. On June 23, 2025, the Texas Commission filed comments and a motion for leave to submit comments out-of-time.

28. On July 1, 2025, MISO filed a motion for leave to file supplemental answer and answer (MISO Supplemental Answer). On July 2, 2025, Vistra filed a motion for leave to respond and response to the MISO Supplemental Answer. On July 3, 2025, Clean Grid Alliance filed a motion for leave to answer and answer to the MISO Supplemental Answer. On July 7, 2025, PIOs filed a motion for leave to answer and answer. On July 9, 2025, Michigan Commission filed a motion for leave to answer and answer to the MISO Answer and MISO Supplemental Answer. On July 11, 2025, MISO filed a motion for leave to file a second supplemental answer and answer (MISO Second Supplemental Answer). On July 15, 2025, Invenergy filed a motion for leave to answer and answer to the MISO Supplemental Answer. On July 15, 2025, Clean Grid Alliance filed a motion for leave to answer and answer to apprise the Commission of new information.

IV. Discussion

A. Procedural Matters

29. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2024), the notices of intervention and timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding.[57]

30. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2024), prohibits answers to a protest unless otherwise ordered by the decisional authority. We accept the answers filed in this proceeding because they have provided information that assisted us in our decision-making process.

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[56] MISO attaches its previous transmittal letter, answers, and supporting testimonies from the Initial ERAS Proposal filing in Docket No. ER25-1674-000 as a supplement to its answer. *See* MISO Answer at 4, Tab B.

[57] Entities that filed comments or protests but did not file a notice of intervention or motion to intervene are not parties to this proceeding. *See* 18 C.F.R. § 385.211(a)(2) (2024) ("The filing of a protest does not make the protestant a party to the proceeding.").

B. Substantive Matters

31. As discussed below, we find that MISO's proposed Tariff revisions implementing the Revised ERAS Proposal are just and reasonable and not unduly discriminatory or preferential, and we accept the Tariff revisions, subject to condition, effective August 6, 2025, as requested.[58] We also find that MISO's proposed Tariff revisions accomplish the purposes of the Commission's final rules on generator interconnection, including Order Nos. 2003 and 2023, by helping to ensure that interconnection customers are able to interconnect to the transmission system in a reliable, efficient, transparent, and timely manner.[59] Therefore, we find that MISO's proposed Tariff revisions meet the independent entity variation standard. Moreover, although several commenters argue for modifications to the Revised ERAS Proposal or suggest alternative solutions for addressing MISO's near-term resource adequacy and reliability needs, the Commission need only determine, under FPA section 205, whether the proposed filing is just and reasonable; the Commission is not obligated to consider whether the proposal is more or less reasonable than other alternatives.[60] We discuss the Revised ERAS Proposal in detail below.

[58] *See NRG Power Mktg., LLC v. FERC*, 862 F.3d 108, 114-15 (D.C. Cir. 2017) (discussing the Commission's authority to propose modifications to a utility's FPA section 205 rate proposal).

[59] Order No. 2003, 104 FERC ¶ 61,103 at PP 26, 827; Order No. 2023, 184 FERC ¶ 61,054 at P 1.

[60] *See, e.g.*, *Cities of Bethany v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir. 1984) (*Cities of Bethany*) (when determining whether a rate was just and reasonable, the Commission properly did not consider "whether a proposed rate schedule is more or less reasonable than alternative rate designs"). Thus, having found MISO's proposal just and reasonable, we need not consider alternative proposals.

1. Resource Adequacy Concerns

a. MISO's Filing

i. Resource Adequacy Concerns

32. MISO states that, as demonstrated by its Reliability Imperative Report,[61] the 2024 OMS-MISO Survey,[62] and the North American Electric Reliability Corporation (NERC) 2024 Long-Term Reliability Assessment,[63] MISO is facing urgent near-term resource adequacy and reliability concerns.[64] MISO states that its resource adequacy concerns are driven by unexpected significant load growth from large data center development, accelerated retirements of baseload generation, increased manufacturing, queue and supply chain delays, and permitting and financing issues. MISO also anticipates long-term load growth driven by increased cooling demands, electric vehicles, and cryptocurrency.[65] MISO states that its Futures Reports[66] have demonstrated the need for

[61] MISO, *MISO's Response to the Reliability Imperative*, Executive Summary 1 (updated Feb. 2024) (Reliability Imperative Report), https://cdn.misoenergy.org/Executive%20Summary%202024%20Reliability%20Imperative%20report%20Feb.%2021%20Final631825.pdf.

[62] OMS and MISO, *2024 OMS-MISO Survey Results* 2 (2024) (2024 OMS-MISO Survey) https://cdn.misoenergy.org/OMS%20MISO%20Survey%20Results%20Workshop%20Presentation628355.pdf.

[63] NERC, *2024 Long-Term Reliability Assessment* (2024) (NERC 2024 Long-Term Reliability Assessment), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

[64] Transmittal at 13-16.

[65] *Id.* at 6.

[66] MISO's Futures Reports include forecasted scenarios designed to capture a range of system conditions over a 20-year planning horizon. The Futures Reports provide the foundation for MISO's local and regional long-term planning and represent "multiple possibilities for future system growth, fuel availability, market conditions, and regulatory environments." *See* MISO, *Future Plan Scenarios* (Apr. 15, 2025) https://www.misoenergy.org/planning/futures-development/.

MISO to take immediate action "to add almost twice the generation that MISO currently has online" over 20 years as a result of this unprecedented load growth.[67]

33. MISO states that the recently published 2025 OMS-MISO Survey[68] found that the near-term resource adequacy risks and uncertainties that MISO faces are intensifying.[69] MISO further states that the 2025 OMS-MISO Survey indicates that at least 3.1 GW of new resources are needed by the summer of 2026/2027 to avoid a resource deficit, and that future years will have greater needs.[70] MISO states that NERC's 2025 Summer Reliability Assessment identified MISO as having an elevated potential for insufficient operating reserves in above normal conditions for the 2025 summer season.[71] MISO adds that, in comments submitted to the Commission's June 2025 Technical Conference[72] regarding resource adequacy, it explained that, despite the rapid growth of wind and solar resources in its region, by 2042, MISO could face a net decline of about 32 GW in available electricity below the 2022 baseline due to the operating characteristics of these

[67] Transmittal at 14 (citing MISO, *MISO Futures Report Series 1A*, at 2 (Nov. 1, 2023) (MISO Futures Report), at Series1A_Futures_Report630735.pdf). MISO predicts an increase of generating capacity from 732 terawatt hours in 2022 to 1,395 terawatt hours in 2042 under the Future 3A scenario. MISO Futures Report at 3.

[68] OMS and MISO, *2025 OMS-MISO Resource Adequacy Survey Results* (2025) (2025 OMS-MISO Survey), https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf

[69] Transmittal at 6 (citing OMS and MISO, *2025 OMS-MISO Resource Adequacy Survey Results*, Fact Sheet (2025 OMS-MISO Survey Fact Sheet), 20 https://cdn.misoenergy.org/2025%20OMS-MISO%20Survey%20Fact%20Sheet702641.pdf).

[70] *Id.* at 15 (citing 2025 OMS-MISO Survey Fact Sheet).

[71] *Id.* at 16.

[72] Technical Conference, *Meeting the Challenge of Resource Adequacy in RTO and ISO Regions*, Docket No. AD25-7-000 (June 4-5, 2025) (June 2025 Technical Conference) (Day 1 https://www.ferc.gov/news-events/events/day-1-commissioner-led-technical-conference-regarding-challenge-resource) (Day 2 https://www.ferc.gov/news-events/events/day-2-commissioner-led-technical-conference-regarding-challenge-resource).

resources.[73] MISO explains that it also highlighted projections that peak load in the region is expected to grow at a 1.6% compound annual growth rate and therefore threatens to outpace the addition of new generating facilities if urgent action is not taken.

34. MISO explains that it has pursued numerous avenues to address its near-term resource adequacy issues, including improving the GIP, implementing a queue cap, and making other queue improvements; however, these updates are unable to address or fill the identified near-term resource gap.[74] MISO adds that the recent queue improvements (i.e., those for increased milestone payments, site control requirements, withdrawal penalties, and the queue cap) are focused on long-term improvements to MISO's queue, and they will not be sufficient to address near-term resource adequacy needs.[75] MISO also asserts that, while interconnection customers can use provisional GIAs to achieve timely interconnection, that process is insufficient to address the need that MISO is facing, both in terms of scale and time frame.[76] MISO states that provisional interconnection service only provides for limited operation and is conditional on DPP studies for full deliverability. MISO states that DPP studies may not be available to recognize the new capacity and may still take years to finalize. MISO further notes that there may be risks associated with having a provisional GIA if the interconnection request is dependent on other interconnection requests in the queue, which may never reach commercial operation due to a lack of an off-taker or load to serve.[77] MISO states that some of the benefits of a provisional GIA are incorporated into ERAS, including increased financial commitments and an expedited timeline.[78] Finally, MISO asserts that only the proposed ERAS process will result in an EGIA that identifies all network upgrades on the MISO transmission system that are necessary to provide deliverability across the transmission system.

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[73] Transmittal at 15 (citing Comments of Todd Ramey, MISO, June 2025 Technical Conference, at 2 (filed May 28, 2025)). *See also* MISO Futures Report at 19.

[74] Transmittal at 36.

[75] *Id.* at 46 n.202.

[76] Witmeier Testimony at 19.

[77] *Id.* at 19-20.

[78] *Id.* at 20.

ii. Revised ERAS Proposal

35. MISO states that ERAS was developed in coordination with its stakeholders to address resource adequacy and reliability needs.[79] MISO further states that because its region is largely comprised of vertically integrated utilities, which are responsible for serving load within their service territories, MISO must partner with the states, their RERRAs, and LSEs to provide a way for the generation necessary for resource adequacy or reliability to be completed quickly.[80] MISO further explains that to incorporate the important jurisdictional interplay among the role of states, other RERRAs, and the Commission, the states in MISO have independent authority for resource adequacy. Due to this, MISO states that its ERAS proposal provides a vehicle for RERRAs to verify to MISO that there is a valid, new incremental load addition not identified in other resource plans or that the proposed generating facility will address an identified resource adequacy deficiency (RERRA verification).[81] MISO states that, following the May 2025 Order, it worked with stakeholders to address concerns about ERAS implementation and to address the Commission's guidance, which has resulted in the Revised ERAS Proposal.[82]

36. MISO proposes various eligibility requirements for interconnection requests seeking interconnection service through ERAS that must be met at the time of an application submission. MISO asserts that the proposed eligibility requirements reflect stakeholder feedback and additional analysis to ensure that a project could efficiently move through the study process while still being considered ready to commence construction, or "shovel ready."[83] MISO proposes the following eligibility requirements for an ERAS interconnection request:[84]

a. New capacity requesting NRIS service must identify the claimed resource adequacy and/or reliability need for which the interconnection request is being submitted and must include: (1) the location of any load to be served (e.g., county and state, electrical bus location(s), and the local resource

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[79] Transmittal at 18-19.

[80] *Id.* at 13.

[81] *Id.* at 9.

[82] *Id.* at 25.

[83] Witmeier Testimony at 40.

[84] *Id.* at 40-41; Transmittal at 8, 36-39.

zone[85]) because a generating facility must be in the same local resource zone as the load to be served unless the identified need is included in a resource filing made to the RERRA; and (2) the peak demand for electricity expected over any one-hour period in MWs (the amount of interconnection service requested must not exceed 150% of the identified MW need).

b. Demonstration of a resource adequacy need through each of the following:

    i. A written verification from the RERRA that either:

        1. The new, incremental load addition is valid and not otherwise included in a resource plan or other process under the purview of the RERRA;

        2. The generating facility will address a resource adequacy deficiency as determined by the RERRA, state, LSE, or interconnection customer and can be supported by a range of documentation; or

        3. For a generating facility that will address a resource adequacy deficiency and serves retail choice load or a retail choice state (i.e., Illinois or Michigan), the interconnection customer will not be required to provide a RERRA verification, but the RERRA will have an opportunity to contest the interconnection request's inclusion in ERAS; and

    ii. An executed agreement evidencing that the proposed generating facility is intended to be used by the entity with the claimed resource adequacy or reliability need.

c. A non-refundable deposit (D1) of $100,000 and a refundable milestone payment (M2) of $24,000 per MW.

d. 100% site control for both the generator and interconnection customer's interconnection facilities.

[85] Local Resource Zone is proposed to mean "a geographic area within the Transmission Provider Region that is prescribed by the Transmission Provider, based upon the criteria in Section 68A.3, to address congestion that limits Planning Resource deliverability." MISO, Proposed Tariff, attach. X (GIP) (175.0.0), § 1 (Definitions).

e. A requested commercial operation date that is no more than three years from the date of submission of an interconnection request, unless the interconnection request is deferred to a later ERAS quarterly study period.

37. MISO states that, in response to the Commission's findings in the May 2025 Order, it proposes requirements for an ERAS interconnection request to be located in the same Local Resource Zone as the resource adequacy or reliability need that it will address.[86] MISO states that adding this requirement better establishes a nexus between the load need and the ERAS interconnection request. MISO asserts that including this requirement will ensure that the proposed generating facility supports Local Clearing Requirements, which is the minimum amount of seasonal accredited capacity for a Local Resource Zone that is required to meet its seasonal loss of load expectation,[87] and will prevent the proposed generating facility from driving import or export concerns. MISO further asserts that requiring the interconnection request to serve a local load will negate the need for transmission investment, reduce import needs from other Local Resource Zones, and remove price divergences between load and generation.[88] MISO states that it will allow an ERAS interconnection request to be located in a different Local Resource Zone than the load it will address if the ERAS interconnection customer can demonstrate that the use of the proposed ERAS generating facility was included in a resource filing or other submission made to the RERRA.[89]

38. MISO explains that, under the current DPP process, an interconnection request may not become commercially operational for up to 11 years after the initial submission.[90] MISO argues that given the urgent near-term resource adequacy needs in

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[86] Transmittal at 32.

[87] MISO defines Local Clearing Requirements as "The minimum amount of Seasonal Accredited Capacity for [a local resource zone] that is required to meet its LOLE for each Season while fully using the Zonal Import Ability for such [local resource zone] and accounting for controllable exports." *See* MISO, FERC Electric Tariff, § II, Module A, § 1 (Definitions-L) (47.0.0).

[88] Witmeier Testimony at 61.

[89] Transmittal at 33.

[90] Witmeier Testimony at 47. Specifically, Mr. Witmeier testifies that the maximum of 11 years can occur because: (1) a DPP interconnection customer may request a commercial operation date up to five years from the submission of the interconnection request; (2) during GIA negotiations, the commercial operation date may be extended up to three years based on specific circumstances set forth in GIP

its region, another mechanism is needed to ensure that ERAS generating facilities come online as soon as possible. MISO states that ERAS generating facilities will continue to have the additional three-year grace period from the commercial operation date listed in Appendix B of the EGIA to become commercially operational that is currently provided to interconnection customers under MISO's *pro forma* GIA.[91] MISO asserts that, in conjunction with the other eligibility requirements, the commercial operation date requirements will ensure that only "shovel ready" projects are submitted.[92]

b. Responsive Pleadings

i. Comments in Support

39. The Arkansas Governor, Indiana Governor, Louisiana Governor, Mississippi Governor, and Missouri Governor submitted comments in support of MISO's filing as a necessary temporary measure to address resource adequacy concerns. In their respective comments, the Governors cite concerns over resource adequacy that they believe the Revised ERAS Proposal will address, including unprecedented load growth, accelerated resource retirements, and delays in new resource additions.[93]

40. Several commenters assert that ERAS is necessary to address near-term resource adequacy needs in the MISO footprint.[94] In particular, several commenters argue that the

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section 4.4.4; and (3) MISO's *pro forma* GIA permits a three-year grace period for generating facilities to achieve commercial operation. *Id.*

[91] Transmittal at 50; Witmeier Testimony at 47. The proposed GIP states that the EGIA "shall take the form of MISO's *pro forma* GIA modified for the [ERAS]." MISO, Proposed Tariff, attach. X (GIP) (175.0.0), § 1 (Definitions).

[92] Witmeier Testimony at 31.

[93] Arkansas Governor Comments at 1; Indiana Governor Comments at 1; Louisiana Governor Comments at 1; Mississippi Governor Comments at 1; Missouri Governor Comments at 1.

[94] AECS Comments at 4; Ameren Comments at 1, 3; Arkansas Commission Comments at 3; Big Rivers Electric Comments at 3; CenterPoint Comments at 1, 4; Consumers Energy Comments at 2-3; Duke Energy Indiana Comments at 2; Entergy/Cleco/Cooperative Energy Comments at 9-10; ITC Comments at 3; Louisiana and Mississippi Commissions Comments at 5; Midwest TDUs Comments at 3-4; MISO TOs Comments at 3; Wisconsin Utilities Comments at 4; Texas Commission Comments at 13.

accelerated review of urgently needed, "shovel ready" projects will help alleviate near-term resource adequacy needs.[95]

41. Several commenters cite concerns about the ability of MISO's DPP process to effectively meet resource adequacy needs and claim that ERAS provides an alternative mechanism to meet such needs.[96] Illinois Commission asserts that these queue problems will likely be compounded by rapid new load growth, especially resulting from the development of data centers throughout the region.[97]

42. Several commenters state that there is an urgent need to address resource adequacy and reliability challenges due to rapid load growth and that the ERAS process is a measure to address such large load growth.[98] More specifically, Big Rivers Electric and MISO TOs cite concerns over resource adequacy driven by a combination of electrification, a resurgence in manufacturing, rapidly growing demand from energy-intensive data centers, accelerated generating facility retirement, and a growing shift toward low or zero-carbon technologies.[99] MISO TOs and the Missouri Commission also note that ERAS can help address resource adequacy needs related to accelerated retirements.[100] Several commenters also state that they expect significant increases in demand on MISO's transmission system because of potential state and

[95] AECS Comments at 4; Big Rivers Electric Comments at 3; CenterPoint Comments at 1; Entergy/Cleco/Cooperative Energy Comments at 9-10; ITC Comments at 3; Louisiana and Mississippi Commissions Comments at 5; Midwest TDUs Comments at 3-4; MISO TOs Comments at 3.

[96] AECS Comments at 2-3; Ameren Comments at 2; CenterPoint Comments at 4; Entergy/Cleco/Cooperative Energy Comments at 7-8; Illinois Commission Comments at 6; Louisiana and Mississippi Commissions Comments at 5; Midwest TDUs Comments at 3-4; Otter Tail Comments at 4.

[97] Illinois Commission Comments at 6-7.

[98] AECS Comments at 2-3; Ameren Comments at 1, 3-4; CenterPoint Comments at 4; Entergy/Cleco/Cooperative Energy Comments at 7-8; Louisiana and Mississippi Commissions Comments at 5; Missouri Commission Comments at 3.

[99] Big Rivers Electric Comments at 2; MISO TOs Comments at 12.

[100] MISO TOs Comments at 12; Missouri Commission Comments at 3.

regional economic growth opportunities in the form of large-scale industrial, manufacturing, and technology-driven projects.[101]

43. ITC and NIPSCO cite to expected capacity shortfalls predicted in the OMS-MISO Survey and the NERC Long-Term Reliability Assessment and Summer Reliability Assessment as evidence that MISO is facing significant resource adequacy risks in the near-term and as justification for the Revised ERAS Proposal. MISO TOs also cite to the OMS-MISO Survey's findings that at least 3.1 GW of additional capacity beyond committed capacity will be needed to meet the projected planning reserve margin forecast.[102] ITC also cites rising summer temperatures as a concern for reliability.[103]

44. DTE Electric asserts that MISO's Revised ERAS Proposal is a reasonable, well-intentioned resource adequacy stop-gap measure designed to shore up emergent needs across the MISO footprint.[104] Furthermore, DTE Electric asserts that this proactive planning measure is just and reasonable and will serve MISO's footprint effectively and efficiently in the near term because it is limited, flexible, and transparent.

45. The Indiana Energy Association argues that the Revised ERAS Proposal is a necessary and balanced approach to meeting the resource adequacy challenges of growing complexity in the energy landscape and ensuring resources are available to meet immediate and future demand.[105]

46. CenterPoint argues that the Revised ERAS Proposal provides a reasonable and appropriate tool to address potential unprecedented customer demand growth, the need to replace retired and retiring generation resources in a manner that does not compromise resource adequacy and reliability on the MISO transmission system, and existing delays and bottlenecks in MISO's current interconnection study process caused by an unprecedented number of interconnection requests.[106] Additionally, CenterPoint asserts that MISO's Revised ERAS Proposal is intentionally designed with significant

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[101] CenterPoint Comments at 4-5; Louisiana and Mississippi Commissions Comments at 5; NIPSCO Comments at 4.

[102] MISO TOs Comments at 12.

[103] ITC Comments at 4; NIPSCO Comments at 3.

[104] DTE Electric Comments at 4.

[105] Indiana Energy Association Comments at 2.

[106] CenterPoint Comments at 6-7.

safeguards to allow ERAS to meet urgently needed resource adequacy and reliability needs while preventing abuse of the ERAS process simply to avoid MISO's DPP.

47. Although Vistra and Michigan Commission filed protests to the Revised ERAS Proposal, they agree with MISO that there are urgent resource adequacy needs in MISO's footprint and generally agree that has MISO has made a good faith effort to create a solution.[107] Michigan Commission asserts that the Revised ERAS Proposal appropriately narrows the ERAS framework to address the Commission's concerns by requiring the identification of a specific load addition or resource adequacy deficiency.[108]

ii. Protests

(a) MISO's Identified Need

48. Several protesters argue that the studies that MISO relies on overstate the short-term risks and ignore near-term solutions in the existing queue, such as existing interconnection requests with signed GIAs or interconnection requests that can use the provisional GIA process.[109] Clean Energy Associations argue that MISO's reliance on the 2025 OMS-MISO Survey is flawed, similar to the Initial ERAS Proposal's reliance on the 2024 OMS-MISO Survey, which included an alternate projection that showed a surplus of 2.9 GW spring capacity in the 2025-2026 planning year.[110] Clean Energy Associations assert that the 2025 OMS-MISO Survey projects that MISO may need 3.1 GW of new resources by 2026/2027 and that MISO's queue and market reforms,

[107] Vistra Protest at 5, 7; Michigan Commission Protest at 7.

[108] Michigan Commission Protest at 7 (citing Transmittal at 27-30).

[109] Clean Energy Associations Protest at 24; Clean Grid Alliance Protest at 9, 34-35; PIOs Protest at 29. *See also* Clean Energy Associations Protest, Ex. A; Clean Energy Associations Protest, Docket No. ER25-1674-000, at 48 (filed Apr. 7, 2025) (Clean Energy Associations Docket No. ER25-1674 Protest); MISO IPPs Protest, attach. A, MISO Independent Power Producers Protest, Docket No. ER25-1674-000, at 3-5, 26-29 (filed Apr. 7, 2025) (MISO IPPs Docket No. ER25-1674 Protest); MISO IPPs Protest, attach. B; NextEra Energy Resources, LLC Protest, Docket No. ER25-1674-000 (filed Apr. 7, 2025) (NextEra Docket No. ER25-1674 Protest; NextEra Docket No. ER25-2674 Protest at Ex. A-1, The Brattle Group Report, at 14-15 (2025 Brattle Group Report); PIOs Protest, attach. A, Public Interest Organizations Protest, Docket No. ER25-1674-000, at 28-35 (filed June 16, 2025) (PIOs Docket No. ER25-1674 Protest).

[110] Clean Energy Associations Protest at 25-26 (citing 2024 OMS-MISO Survey at 21).

improved resource deployment timelines, and other initiatives will help MISO maintain resource adequacy through 2031.[111] Clean Energy Associations further assert that the 2025 OMS-MISO Survey used new projections that showed a potential surplus between 1.4-6.1 GW in accredited capacity against the planning reserve margin requirement for both the winter and summer seasons, which further suggests that LSEs may have adequate resources to meet load reserve requirements in each zone over a five-year horizon.[112] Clean Energy Associations contend that the 2025 OMS-MISO Survey demonstrates that MISO's current trajectory can maintain resource adequacy and can achieve surplus capacity without ERAS.[113] Clean Grid Alliance also argues that MISO's reference to its own reports and comments in the June 2025 Technical Conference are insufficient to support its Revised ERAS Proposal.[114]

49. Several protesters argue that MISO's independent market monitor (IMM) has also affirmed their concerns that MISO's near-term resource adequacy needs are overstated.[115] Clean Energy Associations assert that the IMM stated that MISO is more than resource adequate going into the summer of 2025 and does not have substantial concerns about the MISO region in the near term.[116] Clean Grid Alliance further points out that the IMM stated that MISO's risks are "not nearly as daunting as portrayed by MISO planning reports."[117] Clean Energy Associations and PIOs further state that the IMM found that MISO planning reports and the NERC 2024 Long-Term Reliability Assessment significantly understate available capacity by failing to fully account for demand response, behind-the-meter generation, and firm capacity imports – where MISO has more than 8 GW of underrecognized capability.[118] PIOs add that MISO's reliance on the Commission's 2025 Summer Energy Market and Electric Reliability Assessment, as well

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[111] *Id.* at 26 (citing 2025 OMS-MISO Survey at 2).

[112] *Id.* (citing 2025 OMS-MISO Survey at 7, 9).

[113] *Id.* at 26-27.

[114] Clean Grid Alliance Protest at 7-8.

[115] *Id.* at 8; Clean Energy Associations Protest at 27-29; PIOs Protest at 27-29.

[116] Clean Energy Associations Protest at 27 (citing Comments of David B. Patton, Ph.D., MISO Independent Market Monitor, June 2025 Technical Conference, at 2 (filed May 28, 2025) (Patton Technical Conference Comments)).

[117] Clean Grid Alliance Protest at 8.

[118] Clean Energy Associations Protest at 27-28 (citing Patton Technical Conference Comments at 2); PIOs Protest at 28 (citing same).

as the 2025 OMS-MISO Survey, are vulnerable to the same flaws pointed out by the IMM because such reports are based largely on the flawed NERC 2024 Long-Term Reliability Assessment.[119] PIOs also contend that MISO leans on historical interconnection rates, which do not reflect the various queue reforms the Commission has recently approved for MISO.

50. Several protesters argue that in analyzing near-term resource adequacy needs, MISO fails to consider its existing DPP, which they believe are adequate to meet MISO's near-term resource adequacy and reliability concerns.[120] Specifically, protesters aver that MISO ignores the 56 GW of generation in the DPP queue with GIAs, which are expected to come online before ERAS interconnection requests.[121] Additionally, PIOs assert that MISO fails to recognize that existing DPP interconnection requests may be able to meet its resource adequacy and reliability needs. PIOs claim that even if only 21% of the current DPP interconnection requests reach GIAs, then more than 64 GW of new capacity would have signed GIAs before ERAS is complete.[122] Protesters also point to MISO's existing provisional GIA process,[123] as well as its surplus interconnection and replacement generating facility processes,[124] as alternative processes that will help MISO meet its resource adequacy needs, which MISO fails to take into consideration. Clean Grid Alliance and PIOs also contend that MISO has demonstrated through its new automation software, Pearl Street's Suite of Unified Grid Analysis and Renewables (SUGAR), that the amount of time for an interconnection request to receive a GIA has been reduced to months, which undermines MISO's claims regarding the timing of DPP interconnection requests.[125]

51. Protesters therefore assert that MISO's capacity needs can be addressed by fully leveraging the resources already in the queue, improving interconnection timelines, and

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[119] PIOs Protest at 28 (citing, among others, FERC, *Summer Energy Market and Electric Reliability Assessment* (May 15, 2025), https://www ferc.gov/newsevents/news/ferc-releases2025-summer-assessment).

[120] Clean Energy Associations Docket No. ER25-1674 Protest at 50; NextEra Docket No. ER25-1674 Protest at 5.

[121] Clean Grid Alliance Protest at 9; PIOs Docket No. ER25-1674 Protest at 29-32.

[122] PIOs Protest at 31.

[123] Clean Grid Alliance Protest at 5-6.

[124] PIOs Protest at 29.

[125] *Id.* at 32; Clean Grid Alliance Protest at 9.

prioritizing surplus projects already in the interconnection queue that have on-shored their supply chains, making the ERAS proposal unnecessary.[126] Relatedly, Illinois Commission states that MISO should focus on improving the effectiveness and expeditiousness of the DPP queue, and ERAS should not be allowed to evolve into a second, parallel interconnection queue.[127]

52. Constellation asserts that the Revised ERAS Proposal does not address the Commission's concerns that ERAS is not narrowly tailored to only include interconnection requests capable of addressing identified near-term resource adequacy or reliability needs.[128]

(b) Commercial Operation Date

53. Clean Energy Associations assert that the Revised ERAS Proposal is not sufficiently tailored to ensure that only those resources capable of addressing identified near-term resource adequacy or reliability needs are eligible because of the commercial operation date.[129] Clean Energy Associations argue that the Revised ERAS Proposal does not address near-term issues because: (1) the requirement that the commercial operation date be achieved within three years can be extended if the interconnection request is deferred to a later quarterly study period, and (2) the three-year grace period further extends the commercial operation deadline. Clean Energy Associations thus assert that ERAS interconnection requests may come online as late as 2033. In response to MISO's contention that the commercial operation date provisions are necessary to account for delays outside of MISO's control, Clean Energy Associations assert that MISO has failed to tailor the aspects of its proposal that are within its control, such as using an ongoing quarterly study process rather than a one-time study.[130]

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[126] Clean Energy Associations Protest at 28; Clean Grid Alliance Protest at 3, 9, 34, 41; PIOs Protest at 29-32.

[127] Illinois Commission Comments at 7.

[128] Constellation Protest at 2-4.

[129] Clean Energy Associations Protest at 9.

[130] *Id.* at 9-10 (citing Transmittal at 13, 36).

54. Several protesters contend that the problem is the supply chain and not MISO's DPP, because all interconnection customers rely on the same supply chains.[131] Clean Grid Alliance further contends that these universal supply chain issues are evidenced by MISO's commercial operation date blanket waiver filed at the Commission in recent years.[132] These protesters argue that ERAS interconnection requests may still face these challenges and may not achieve commercial operation any faster than DPP interconnection requests.[133] According to Clean Energy Associations, the ERAS process may compound these issues for DPP interconnection customers if the ERAS interconnection customers deplete existing resources.[134] Clean Energy Associations assert that, while these delays may be beyond MISO's control, MISO's attention would be better suited to understanding and addressing those issues than the ERAS process. NextEra further argues that a lack of requirements or criteria for prioritizing resources that use existing transmission capacity or minimize the need for new network upgrades will make ERAS more susceptible to ongoing supply chain delays or may increase the time and costs for constructing required network upgrades; may constrain MISO staff resources; and/or may increase the risk of ERAS interconnection customers dropping out due to high network upgrade costs or long network upgrade construction schedules.[135]

55. Several protesters argue that the Revised ERAS Proposal is not appropriately tailored to timely meet MISO's resource adequacy needs because the commercial operation deadline requirements are too far out into the future.[136] COMPP contends that

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[131] Clean Energy Associations Docket No. ER25-1674 Protest at 46-47; Clean Grid Alliance Protest at 2; MISO IPPs Docket No. ER25-1674 Protest at 28; NextEra Docket No. ER25-1674 Protest at 25.

[132] Clean Grid Alliance Protest at 2. *See also Midcontinent Indep. Sys. Operator, Inc.*, 176 FERC ¶ 61,161 (2021) (granting waiver of the Tariff to allow a one or two-year extension of the commercial operation deadline for certain interconnection requests in MISO's August 2017 DPP West study group).

[133] Clean Energy Associations Docket No. ER25-1674 Protest at 46-47; MISO IPPs Docket No. ER25-1674 Protest at 28; NextEra Docket No. ER25-1674 Protest at 25; 2025 Brattle Group Report at 26.

[134] Clean Energy Associations Docket No. ER25-1674 Protest at 47.

[135] 2025 Brattle Group Report at 26.

[136] Clean Energy Associations Docket No. ER25-1674 Protest at 46; COMPP Protest at 4; Invenergy Protest at 9-10; Michigan Commission Protest 12-14; MISO IPPs Docket No. ER25-1674 Protest at 28; NextEra Docket No. ER25-1674 Protest at 21-22

the Revised ERAS Proposal does not address the Commission's concerns in the May 2025 Order and allows for ERAS interconnection requests to achieve commercial operation as late as 2035, when MISO forecasts a resource adequacy shortfall occurring between 2027 and 2030.[137] Similarly, Invenergy avers that the Revised ERAS Proposal weakens shovel readiness because the commercial operation date requirements would allow interconnection requests to be achieve commercial operation by as late as 2033.[138] MISO IPPs similarly argue that, instead of a three-year grace period, ERAS interconnection requests should be subject to higher penalties for delay or withdrawal than the DPP queue because they are given priority treatment in the ERAS process.[139] Michigan Commission additionally asserts that the Revised ERAS Proposal does not provide a stronger link between the interconnection request and the resource adequacy need because the Revised ERAS Proposal retains the three-year grace period for the commercial operation deadline, which does not narrowly tailor ERAS to only shovel-ready projects capable of meeting near-term resource adequacy challenges.[140] Michigan Commission argues that a three-year grace period, in addition to a three-year commercial operation date requirement for ERAS interconnection requests, is too long given the need for the addition of generating capacity by 2030 and belies the notion of the projects being "shovel ready," in contradiction to ERAS' stated purpose. Michigan Commission states that it is unclear why MISO appears reluctant to either eliminate the grace period or reduce it to one year and allow the Commission waiver process to handle longer lead time requests.

56. PIOs argue that MISO's Revised ERAS Proposal contains conflicting language with respect to the three-year grace period of the commercial operation date.[141]

(citing MISO Transmittal, Docket No. ER25-1674-000 at 21); PIOs Docket No. ER25-1674 Protest at 40-41.

[137] COMPP Protest at 4 (citing May 2025 Order, 191 FERC ¶ 61,131 at P 202). According to COMPP, MISO changed GIP section 4.4.4 to extend commercial operation deadlines for backlogged interconnection requests due to transmission owner construction delays by an additional 2.5 years beyond the three-year grace period, and some of these same transmission owners are seeking to interconnect generating facilities through ERAS. *Id.* n.7. *See Midcontinent Indep. Sys. Operator, Inc.*, 191 FERC ¶ 61,150 (2025).

[138] Invenergy Protest at 9-10.

[139] MISO IPPs Docket No. ER25-1674 Protest at 28.

[140] Michigan Commission Protest at 12-14.

[141] PIOs Protest at 37-38.

According to PIOs, MISO's transmittal states that "[a]ll ERAS projects are eligible to use the grace period of up to three years as documented in GIA Article 2.3.1." However, PIOs assert that Article 2.3.1 of the proposed *pro forma* EGIA does not directly describe a grace period, but instead refers to GIP section 4.4.4, which sets out the potential for a three-year grace period. Meanwhile, PIOs assert, the revised Tariff states that "[a]fter entering [ERAS], no changes to the In-Service Date or Commercial Operation Date of the Generating Facility is permitted via section 4.4.4."[142]

(c) RERRA Verification Requirement

57. Clean Energy Associations and EPSA aver that the RERRA verification does little to link the proposed ERAS interconnection request to the identified resource adequacy or reliability need.[143] Clean Energy Associations assert that the RERRA verification amounts to speculation by a group of states and local agencies that do not coordinate on resource adequacy and do not have the authority to determine the resource adequacy or reliability needs for the MISO-controlled transmission system.[144] Clean Energy Associations assert that proposed GIP section 3.9.1.1.ii allows projects to qualify based on support from a state integrated resource plan or similar mechanism, which directly contradicts the RERRA verification requirement in GIP section 3.9.1.1.i that an interconnection request not already be accounted for in an existing plan or procedure.[145] Clean Energy Associations further argue that the new provision that allows interconnection requests to bypass the Local Resource Zone requirement if an identified need appears in a RERRA's integrated resource plan or comparable document is similarly contradictory.

58. PIOs argue that despite MISO's proposal to change the RERRA requirement from a notification to a verification, it does not require the RERRA to explain its decision and how it compared similarly situated projects to choose the one best positioned to meet near-term resource adequacy needs.[146] PIOs add that nothing in the ERAS process requires a RERRA to consider whether a resource currently in the DPP is better suited to

[142] *Id.* at 38 (citing MISO, Proposed Tariff, attach. X (GIP) (175.0.0), § 3.9.8).

[143] Clean Energy Associations Protest at 11; EPSA Comments at 3.

[144] Clean Energy Associations Protest at 11.

[145] *Id.* at 11-12.

[146] PIOs Protest at 23 (quoting May 2025 Order, 191 FERC ¶ 61,131, (See, Comm'r, consenting at P 6).

meet the identified need.[147] PIOs contend that the first option for the RERRA verification focuses only on the load and not on the generation.

59. EPSA asserts that the Revised ERAS Proposal does not require RERRAs or others to explain why a given interconnection request is best positioned to meet near-term resource adequacy needs.[148] EPSA avers that the RERRA verification process is not objective or transparent enough to ensure that the interconnection requests are essential to addressing resource adequacy and reliability gaps.[149]

60. Several protesters argue that the Revised ERAS Proposal lacks specific criteria for how a RERRA will determine that a resource adequacy need exists and whether ERAS is necessary to meet such need.[150] Further, Invenergy argues that the proposal risks excluding projects that are best suited to meet resource adequacy needs.[151] Invenergy contends that the Revised ERAS Proposal is not narrowly tailored to resource adequacy needs because it lacks objective scoring criteria that the RERRAs will apply, such as was included in PJM Interconnection L.L.C.'s (PJM) Reliability Resource Initiative (RRI).[152] Similarly, EPSA contends that a more clear and specific qualitative scoring mechanism and/or selection process, such as part of the Interconnection Process Enhancements (IPE) that the Commission recently accepted for California Independent System Operator Corporation (CAISO), should be included in the Revised ERAS Proposal to ensure that resources proffered by RERRAs and the states are in fact essential to meet reliability and resource adequacy needs.[153] Invenergy asserts that MISO has not explained how an interconnection request will be evaluated, how a RERRA will target the most essential interconnection requests to address resource adequacy and reliability challenges, or how a

[147] *Id.* at 24.

[148] EPSA Comments at 3.

[149] *Id.* at 3, 6-7.

[150] Clean Energy Associations Docket No. ER25-1674 Protest at 44-45 (citing January 2024 Order, 186 FERC ¶ 61,054 at P 174); Invenergy Protest at 10; 2025 Brattle Group Report at 28.

[151] Invenergy Protest at 14.

[152] *Id.* at 10 (citing *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084 (2025) (PJM RRI Order), (Phillips and Rosner, Comm'rs consenting at P 1)).

[153] EPSA Comments at 3, 7 (citing *Cal. Indep. Sys. Operator Corp.*, 188 FERC ¶ 61,225, at P 173 (2024) (CAISO IPE Order) (accepting amendments to the LGIP in CAISO's tariff)).

RERRA will compare interconnection requests to determine which are best positioned to meet near-term resource adequacy and reliability needs.[154]

61. Constellation argues that the new RERRA verification requirements exacerbate the problems that the Commission highlighted in the May 2025 Order.[155] Constellation asserts that the Revised ERAS Proposal's requirement that, in non-retail-choice states, RERRAs verify specific load additions that projects will support is illusory because the verification "may take any form that works for a specific state."[156] Constellation contends that any number of interconnection requests can meet an identified need, resulting in a RERRA connecting load growth to an interconnection request with little effort.[157] Constellation asserts that, without objective and transparent standards, a RERRA may reject or accept any given interconnection request for inclusion in ERAS because each RERRA will have the exclusive discretion to decide inclusion. Thus, Constellation avers that the Revised ERAS Proposal does not provide objective criteria for RERRA verification to ensure that interconnection requests are best suited to quickly and efficiently meet identified resource adequacy and reliability needs.

(d) Other ERAS Eligibility Criteria

62. Protesters raise several other arguments for why they believe the proposed ERAS eligibility requirements and framework are not tailored to achieve MISO's stated objectives of meeting near-term resource adequacy and reliability needs. PIOs and Invenergy contend that MISO's proposed requirements for site control and NRIS may help to prevent speculative interconnection requests but do not ensure that "shovel ready" interconnection requests enter the ERAS process, such as evidence that major equipment or project permits have been sought or secured.[158] PIOs further contend that because ERAS interconnection customers will be competing with DPP interconnection customers for parts, labor, and necessary services, ERAS interconnection requests are likely to add to the challenges interconnection customers are already facing in getting resources to achieve commercial operation.[159] Invenergy further asserts that the Revised ERAS

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[154] Invenergy Protest at 10-11 (citing May 2025 Order, 191 FERC ¶ 61,131 (See, Comm'r, consenting at P 6)).

[155] Constellation Protest at 2-3.

[156] *Id.* at 3 (citing Transmittal at 30).

[157] *Id.* (citing Transmittal at 13-18).

[158] Invenergy Protest at 9; PIOs Protest at 26.

[159] PIOs Protest at 26.

Proposal is not narrowly tailored due to is lack of objective criteria for interconnection requests to demonstrate shovel readiness.[160] Vistra asserts that the shortened timeline for the initial quarterly study period will likely limit independent power producer interconnection requests to smaller, less capital-intensive projects in order to meet the timeline, thus reducing their ability to meet regional resource adequacy needs.[161] Additionally, Constellation asserts that the serial nature of the ERAS study process means that interconnection requests will be studied on a first-come, first-served basis, which, Constellation contends, will have no bearing on an interconnection request's resource adequacy benefits.[162] According to Constellation, the quarterly study period will exclude interconnection requests within the same study area or impacting the same constraint, which may also harm resource adequacy.

63. Clean Grid Alliance asserts that MISO has not demonstrated how its proposal to study 68 ERAS interconnection requests will solve the claimed generating capacity shortfall or match such interconnection requests to locations where there are claimed needs.[163] Clean Grid Alliance argues that this contrasts with MISO's DPP queue cap, which has a "tether" based on non-coincident peak projections. Clean Grid Alliance further asserts that the Revised ERAS Proposal is not narrowly tailored because, unlike PJM RRI, ERAS will be processed in a separate queue.[164] PIOs contend that MISO's Revised ERAS Proposal, for which the closest comparison is the PJM RRI construct, includes a larger cap than PJM RRI despite MISO having less need for expedited interconnection than PJM.[165] Invenergy argues that MISO's proposed ERAS cap is untethered to resource adequacy or reliability needs due to its lack of scoring criteria.[166] Invenergy further argues that MISO's proposed carve out for independent power producers is not tied to any resource adequacy need or criteria, and as such, MISO may accept all 10 of the allotted independent power producer submissions in the first few

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[160] Invenergy Protest at 3, 8-9.

[161] Vistra Protest at 10.

[162] Constellation Protest at 3-4.

[163] Clean Grid Alliance Protest at 23-24.

[164] *Id.* at 26.

[165] PIOs Protest at 19 (citing FERC, *2024: State of the Markets Staff Report* (Mar. 20, 2025), at 28 (Figure 17)).

[166] Invenergy Protest at 13.

cycles regardless of whether later submitted interconnection requests could better meet an identified need.

iii. Answers

(a) MISO Answer

64. MISO reiterates that there is significant evidence supporting its stated resource adequacy and reliability needs.[167] MISO points to statements made by Commission Chairman Mark Christie, provided during the June 2025 Technical Conference on resource adequacy, that MISO has lost 95 GW of accredited capacity and that load driven by data centers is increasing.[168] At the conference, MISO stated that it is resource adequate today, but that it is also working to slow the decline of other resources in its footprint and that more work is needed to arrest this decline and maintain capacity.[169] MISO recognizes that there was a spectrum of perspectives on the imminency of resource adequacy needs expressed at the conference, but MISO asserts that the general consensus was that MISO's queue is backlogged, retirements are outpacing additions, and load growth is increasing in the near-term. MISO emphasizes that these challenges are being experienced by RTOs/ISOs across the United States.[170]

65. MISO acknowledges that NERC has downgraded the MISO region's risk category for capacity shortfalls to "elevated risk" in the corrected NERC 2024 Long-Term Reliability Assessment, but MISO asserts that this new risk category places the MISO region at the same risk level as the PJM and CAISO regions, both of which recently proposed similar expedited generator interconnection queue processes through the RRI and IPE initiatives, respectfully.[171] MISO states that the corrected NERC 2024

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[167] MISO Answer at 5.

[168] *Id.* at 5-6 (citing June 2025 Technical Conference, Day 2, Panel 5 at 2:00-4:00).

[169] *Id.* at 5-6 (citing June 2025 Technical Conference, Day 2, Panel 5, at 4:00-5:30).

[170] *Id.* at 6 (citing PJM Pre-filed Statement of Manu Asthana, June 2025 Technical Conference, at 2-3 (filed May 20, 2025); Pre-filed Statement of Elliott Mainzer, CAISO, June 2025 Technical Conference, at 7-9 (filed May 28, 2025); Pre-filed Statement of Pallas Lee Van Schaick, ISO-NE External Market Monitor and NYISO Market Monitoring Unit, June 2025 Technical Conference, at 2-4 (filed May 28, 2025); Pre-filed Statement of Gordon van Welie and Stephen George, ISO-NE, June 2025 Technical Conference, at 2-4 (filed May 28, 2025)).

[171] *Id.* (citing NERC, *Statement on NERC's 2024 Long-Term Reliability Assessment* (June 17, 2025) (NERC Statement on 2024 Long-Term Reliability

Long-Term Reliability Assessment places the MISO region into the "high risk" category during the 2028-2031 timeframe, and MISO asserts that this supports its claim that it has imminent resource adequacy and reliability needs. In addition, MISO states that the NERC 2025 Summer Reliability Assessment, which was not impacted by NERC's correction, found that the MISO region has potential for insufficient operating reserves in above-normal conditions.[172]

66. MISO also disagrees with protesters' assertions that the 2024 and 2025 OMS-MISO Surveys do not support the Revised ERAS Proposal.[173] MISO states that there is a general trend of declining generation additions, increased generation retirements, and unexpected large spot load development in the near term; thus, the resource adequacy challenges are broadly recognized and do not depend on the specific findings of one study. MISO contends that it cannot predict where large load development will occur and that it is trying to address resource adequacy and reliability problems that will occur in the future to prevent foreseeable shortfalls.[174] MISO asserts that the Revised ERAS Proposal is necessary to ensure that generation is built in time to meet future resource adequacy needs, even if it is resource adequate today.

67. Further, MISO states that, while protesters argue that MISO's automation efforts will resolve DPP study delays, its automation efforts currently focus only on DPP Phase I, with implementation in the more in-depth DPP Phase II and Phase III studies to occur later.[175] MISO contends that it will take several years before MISO experiences the benefit of recent reforms such as SUGAR implementation, GIP improvements, and the

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Assessment) https://www.nerc.com/news/Pages/Statement-on-NERC%E2%80%99s-2024-Long-Term-Reliability-Assessment.aspx).

[172] *Id.* at 7 (citing NERC Statement on 2024 Long-Term Reliability Assessment; NERC, *2025 Summer Reliability Assessment* 6 (May 2025), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf).

[173] *Id.* (citing Clean Energy Associations Protest at 25-26; PIOs Protest at 29-33).

[174] *Id.* at 7-8.

[175] *Id.* at Tab B, Prepared Direct Testimony of Andrew Witmeier, Docket No. ER25-1674-000, at 10 (filed Apr. 21, 2025) (Witmeier Docket No. ER25-1674 Rebuttal Testimony).

2024 MISO Queue Cap, and ERAS is a separate process to address near-term resource adequacy needs.[176]

68. MISO also asserts that COMPP confuses the commercial operation date with the in-service date in arguing that the commercial operation date requirement was not appropriately tailored for ERAS interconnection requests to timely meet resource adequacy needs.[177] MISO explains that the Commission recently accepted, in Docket No. ER25-1758, revisions to its GIP that allow transmission owners to extend the in-service date during GIA negotiations for known construction delays, and to set a 180-day trial operation period after the in-service date. MISO contends that the 180-day trial operation period after the in-service date prevents the termination of an otherwise viable project in the very limited circumstance that the transmission owner had moved the in-service date for a facility that it was building and that was needed to allow a generating facility to provide its full output to the transmission system.[178] MISO states that these provisions do not allow the interconnection customer to extend its own commercial operation date grace period when the transmission system is ready to receive full output and do not impact commercial operation date timing requirements in GIP section 4.4.4 or *pro forma* GIA Article 2.3.1. MISO states that the grace period in the Revised ERAS Proposal is unchanged from the Initial ERAS Proposal and does not undercut the rationale for ERAS. MISO further asserts that any interconnection request can face in-service date and other delays and that arguments asserting that an interconnection request is not urgent because it may face in-service date delays are spurious. MISO asserts that the Revised ERAS Proposal accelerates those parts of the timeline that MISO can control.

69. Additionally, MISO states that the Revised ERAS Proposal better tailors the RERRAs' roles in ERAS to address resource adequacy needs because the new RERRA verification targets the resource adequacy need that an interconnection request is addressing and ensures that the interconnection request will address a new load addition or resource adequacy deficiency in the RERRA's footprint.[179] MISO explains that since resource adequacy determinations must be made in collaboration with the states, MISO relies on the RERRA to review and verify that the proposed interconnection request will

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[176] MISO Answer, Tab B, MISO Answer, Docket No. ER25-1674-000, at 41 (filed Apr. 21, 2025) (MISO Docket No. ER25-1674 Answer).

[177] MISO Answer at 8-9 (citing *Midcontinent Indep. Sys. Operator, Inc.*, 191 FERC ¶ 61,150; *see* MISO, Tariff, attach. X (GIP) (171.0.0), § 4.4.4.1).

[178] *Id.* at 9-10.

[179] *Id.* at 21.

address the identified need.[180] MISO states that the new verification requirement narrows ERAS interconnection requests to those that can address a resource adequacy need that a RERRA has verified is a valid, new, incremental load that is not already planned for, and for which an executed agreement exists connecting that need to the specific project.[181]

(b) Additional Answers

70. Clean Grid Alliance asserts that MISO's answer did not address the resource adequacy challenges that protesters raised and, instead, relied on NERC's new assessment downgrading MISO's risk to one similar to other RTOs/ISOs.[182] Clean Grid Alliance contends that, contrary to MISO's implications, the Commission did not grant exceptions to open access based on NERC capacity ratings. Further, Clean Grid Alliance reiterates that MISO has abundant generation because MISO has 56 GW of interconnection requests with GIAs and a large number of interconnection requests in the DPP 2021 and 2023 cycles that, according to MISO, will have GIAs in 2025 and 2026.[183] Clean Grid Alliance also contends that ERAS is unjustified and unnecessary because the provisional GIA process allows new generation to interconnect quickly.[184] Clean Grid Alliance further argues that MISO admits that ERAS projects may not be approved in state regulatory processes and may have to withdraw, which is contrary to MISO's claims that ERAS projects will be "shovel ready."[185]

71. Clean Grid Alliance reiterates that supply chain issues are the true cause of the DPP queue backlogs, which is evidenced by MISO's recent request for a blanket waiver to extend commercial operation deadlines for interconnection requests in the DPP 2018

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[180] *Id.* at 22.

[181] *Id.* at 22-23.

[182] Clean Grid Alliance First Answer at 2-3 (citing Clean Grid Alliance Protest at 8; MISO Answer at 6). *See also* Clean Grid Alliance First Answer, attach. A (Clean Grid Alliance Answer), Docket No. ER25-1674-000 at 10 (filed May 2, 2025) (Clean Grid Alliance Docket No. ER25-1674 Answer).

[183] Clean Grid Alliance First Answer at 3; Clean Grid Alliance Docket No. ER25-1674 Answer at 11, 15.

[184] Clean Grid Alliance First Answer at 3, 5-6; Clean Grid Alliance Docket No. ER25-1674 Answer at 12-13.

[185] Clean Grid Alliance Docket No. ER25-1674 Answer at 13-14 (citing MISO Docket No. ER25-1674 Answer).

and 2019 cycles, citing supply chain issues.[186] Clean Grid Alliance avers that NERC also recognizes that supply chain issues are causing construction delays, resulting in a 2.7 GW shortfall in MISO's service territory.[187] Clean Grid Alliance asserts that establishing a separate ERAS study process is not going to solve the supply chain problem and may result in ERAS interconnection requests developing behind DPP interconnection requests with GIAs and those expected to finalize GIAs in 2025 and 2026.

72. Clean Grid Alliance asserts that LSEs and MISO correctly recognize that spot load is speculative and that there are only potential load growth issues.[188] Clean Grid Alliance avers that some LSEs identify specific generation needs but do not address why DPP interconnection requests cannot meet that load. Clean Grid Alliance also points out that other LSEs do not identify any specific needs.[189]

73. Finally, Clean Grid Alliance asserts that MISO is close to achieving a one-year processing time for its future DPP cycles due to implementing queue processing improvements, including the SUGAR software.[190] Clean Grid Alliance contends that MISO will be able to serve state load needs with resources in its DPP queue and that ERAS is thus unnecessary.

74. MISO IPPs aver that MISO's answer illustrates that the Revised ERAS Proposal is not narrowly tailored because MISO has not proffered any evidence connecting its proposed ERAS cap or carve outs with the magnitude of the anticipated resource adequacy shortfall, nor how the Revised ERAS Proposal will meet the timing of MISO's anticipated shortfall given that ERAS interconnection requests may not come online until 2032.[191]

75. Clean Energy Associations note that, in the time since MISO filed the Revised ERAS Proposal, NERC has revised the 2024 Long-Term Reliability Assessment to redesignate the MISO region from the "high risk" category to the "elevated risk"

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[186] Clean Grid Alliance First Answer at 4 (citing Clean Grid Alliance Protest at 2); Clean Grid Alliance Docket No. ER25-1674 Answer at 11.

[187] Clean Grid Alliance First Answer at 4-5 (citing the NERC 2024 Long-Term Reliability Assessment at 43).

[188] *Id.* at 5-6 (citing MISO Answer at 7; Clean Grid Alliance Protest at 33).

[189] *Id.* at 6-7.

[190] Clean Grid Alliance Docket No. ER25-1674 Answer at 15.

[191] MISO IPPs Answer at 15.

category.[192] Clean Energy Associations assert that MISO, despite acknowledging the downgrade in its answer, still relies on the NERC definition of "high risk" to support its claimed imminent resource adequacy and reliability concerns.[193] Therefore, Clean Energy Associations argue that MISO's rationale for ERAS is based on inaccurate and overstated resource adequacy projections.[194]

76. Clean Energy Associations note that the 2025 OMS-MISO Survey demonstrates that the MISO region can maintain resource adequacy through 2031 through DPP and market reforms, improved resource deployment timelines, and other initiatives.[195] Clean Energy Associations argue that MISO fails to provide any evidence to rebut this statement from the 2025 OMS-MISO Survey or similar statements made by its IMM.[196] Accordingly, Clean Energy Associations assert that MISO already has the processes needed to address future resource adequacy problems. Clean Energy Associations further assert that, absent clear evidence of a near-term shortfall, there is no basis to adopt a new, preferential interconnection process.[197]

77. PIOs assert that MISO has neither addressed that its need to demonstrate that near-term resource adequacy needs justify the Revised ERAS Proposal nor why existing processes in MISO's Tariff are insufficient to meet its resource adequacy needs.[198]

78. PIOs argue that MISO's answer dismisses evidence regarding its resource adequacy needs.[199] PIOs contend that despite MISO's recognition of NERC's downgrading of MISO's risk assessment, MISO does not propose any adjustment to its Revised ERAS Proposal. PIOs further contend that, in arguing that its resource needs are equivalent to those of PJM and CAISO, MISO ignores critical differences among the Revised ERAS Proposal, PJM's RRI, and CAISO's IPE. Specifically, PIOs explain that

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[192] Clean Energy Associations Answer at 3 (citing NERC Statement on 2024 Long-Term Reliability Assessment).

[193] *Id.* (citing MISO Answer at 7).

[194] *Id.* at 5.

[195] *Id.* at 3-4 (citing 2025 OMS-MISO Survey at 2).

[196] *Id.* at 4 (citing Clean Energy Associations Protest at 27-28).

[197] *Id.* at 5.

[198] PIOs Answer at 2.

[199] *Id.* at 3-4.

PJM has more significant issues with new entry and retirement of generating facilities compared to MISO, yet the RRI process has a smaller cap and stricter timeline criteria than the Revised ERAS Proposal. Further, PIOs state that CAISO's process prioritizes interconnection requests in the queue through scoring criteria rather than allowing new interconnection requests to "cut in line."[200]

79. PIOs argue that MISO continues to ignore significant timeline mismatches between its identified needs and the ERAS process. PIOs further argue that MISO's references to various timelines obfuscates the reality that ERAS interconnection requests are not more suited to meet near-term resource adequacy needs than interconnection requests in the DPP, particularly given the adoption of the SUGAR software through which MISO expects to process DPP backlogs by the end of 2026.[201]

80. PIOs argue that MISO's answer mistakes PIOs' and COMPP's concerns about the in-service date and commercial operation date to be solely about Tariff details and implementation, when the concern is more broadly that the Revised ERAS Proposal does not require ERAS interconnection requests to reach commercial operation in the near term.[202] PIOs contend that MISO's explanation that the Revised ERAS Proposal is only intended to accelerate the parts of the generator interconnection process that MISO can control demonstrates that the Revised ERAS Proposal does not include mechanisms to ensure that resources come online to meet near-term needs.[203] PIOs further contend that this explanation contradicts MISO's other statements that ERAS guarantees that only "shovel ready" interconnection requests will enter ERAS since MISO can only control certain aspects of the interconnection process, which will not be sufficient to ensure genuine shovel-readiness. PIOs assert that MISO's explanations also conflict with PJM's RRI, which includes indicators of readiness like a construction schedule and attestations of commercial operation timelines.[204]

c. Commission Determination

81. We find that MISO's Revised ERAS Proposal represents a just and reasonable and not unduly discriminatory or preferential approach for addressing MISO's urgent, near-term resource adequacy needs. MISO has authority to evaluate and maintain

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[200] *Id.* at 4.

[201] *Id.* at 4-5.

[202] *Id.* at 5.

[203] *Id.* at 6.

[204] *Id.* (citing PJM RRI Order, 190 FERC ¶ 61,084 at P 155).

resource adequacy under its Tariff mechanisms,[205] as well as to manage the processing of its queue.[206] We find that the Revised ERAS Proposal will allow MISO to accelerate the study of interconnection requests that are "shovel ready" and that will address an identified resource adequacy or reliability need in the same Local Resource Zone where the generating facility is to be located, with limited exceptions, thereby enabling resources to meet projected near-term resource adequacy needs more quickly than could be accomplished under MISO's current DPP process.

(a) MISO's Identified Need

82. We disagree with protesters that MISO has not sufficiently supported its near-term resource adequacy needs. While some protesters contend that MISO overstates its near-term resource adequacy needs, MISO cites several reports from different sources – MISO's Reliability Imperative Report, the 2024 and 2025 OMS-MISO Surveys, and the NERC 2024 Long-Term Reliability Assessment – as evidence of its near-term resource adequacy needs.[207] For example, while Clean Energy Associations assert that the 2025 OMS-MISO Survey projects a surplus of 1.4-6.1 GW, the next bullet in the survey results states that "at least 3.1 GW of additional capacity beyond the committed capacity will be needed to meet the projected planning reserve margin forecast."[208] Several commenters, both LSEs and state representatives, and some protesters have highlighted their near-term load-serving obligations and upcoming load needs.[209] MISO also asserts that the data it relies on, as well as the overall trends for

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[205] *See Midcontinent Indep. Sys. Operator, Inc.*, 162 FERC ¶ 61,176, at P 59 (2018) ("MISO's resource adequacy construct ensures just and reasonable rates by creating a price signal that reflects the availability of capacity rather than by creating any particular price"); *see also* January 2024 Order, 186 FERC ¶ 61,054 at P 182 ("[A]ny future section 205 filing to propose a study cycle cap must demonstrate how the cap ensures that MISO can study new generation seeking to interconnect in a manner that appropriately accounts for its future resource adequacy needs.").

[206] *See* PJM RRI Order, 190 FERC ¶ 61,084 at P 54 (citing *Sw. Power Pool, Inc.*, 128 FERC ¶ 61,114, at PP 15, 32 (2009) (finding that an RTO is entitled to flexibility in proposing variations to Commission requirements under the independent entity variation standard and that the RTOs' temporal and geographic queue clustering proposal was a rational approach), *order on compliance*, 129 FERC ¶ 61,226 (2009), *order on compliance*, 133 FERC ¶ 61,139 (2010)).

[207] Transmittal at 5-6.

[208] 2025 OMS-MISO Survey at 2.

[209] *See, e.g.*, AECS Comments at 4; CenterPoint Comments at 1; Entergy/Cleco/Cooperative Energy Comments at 9-10; ITC Comments at 3; Louisiana

RTOs/ISOs throughout the country, support its claims about near-term resource adequacy needs.[210] While forecasting future resource adequacy needs necessarily involves uncertainty, we find that it is reasonable for MISO to act in recognition of the aforementioned reports. Further, we note that while NERC recently revised its 2024 Long-Term Reliability Assessment, MISO's risk classification for the years 2028-2031, remains in the "high risk" category.[211] ERAS provides a mechanism to accelerate the interconnection of resources to help address resource adequacy needs in MISO's footprint during this period. And as MISO points out, although NERC has downgraded the MISO region's risk category for capacity shortfalls to "elevated risk" before 2028, this new risk category places the MISO region at the same risk level as the PJM and CAISO regions, for which the Commission has also approved expedited generator interconnection study processes to address pressing resource adequacy needs.[212] We therefore find that MISO has sufficiently demonstrated that it has near-term resource adequacy needs in its region.

83. As for protesters' arguments about how the DPP process may meet MISO's identified resource adequacy needs in lieu of ERAS, we note that the Commission has extended RTOs/ISOs considerable flexibility in addressing region-specific interconnection study processing challenges.[213] In light of our finding that MISO's proposal is just and reasonable, we need not consider whether the proposal is more or less reasonable than the alternative solutions identified by protesters. Notwithstanding this, we disagree with arguments that MISO's recent interconnection study process reforms and study automation efforts will render the ERAS proposal unnecessary. While MISO's automation efforts may improve the overall DPP process,[214] those processing improvements are just now being implemented for the first time for the DPP 2022 cycle, which will not be completed for another year or more, and therefore are unlikely to be sufficient to meet MISO's near-term resource adequacy needs. At this time, only the system impact studies in the DPP process are being automated, while the ERAS

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and Mississippi Commissions Comments at 5; Michigan Commission Protest at 7; Midwest TDUs Comments at 3-4; MISO TOs Comments at 3; Mississippi Governor Comments at 1; Vistra Protest at 5, 7.

[210] MISO Answer at 5-8.

[211] Transmittal at 6 (citing the NERC 2024 Long-Term Reliability Assessment).

[212] *See* MISO Answer at 6.

[213] *See* PJM RRI Order, 190 FERC ¶ 61,084 at P 54.

[214] Witmeier Testimony at 64-65.

framework is designed to render EGIAs within 90 days,[215] with the entire ERAS process likely concluding well in advance of full implementation of DPP automation enhancement reforms.[216] Similarly, we agree with MISO that its interconnection study process reforms (e.g., the 2024 MISO Queue Cap) are focused on longer-term improvements to reduce speculative interconnection requests from entering the DPP queue and improve queue processing, not the objective of addressing near-term resource adequacy and reliability needs.

(b) Commercial Operation Date

84. Further, we disagree with protesters that MISO's proposed commercial operation date requirements undercut MISO's contention that ERAS interconnection requests will help resolve near-term resource adequacy needs. Under the Revised ERAS Proposal, interconnection customers must have a commercial operation date within three years of interconnection request submission, subject to an additional three-year grace period. Protesters argue that, as a result, ERAS generating facilities that will not come online for at least six years after interconnection request submission, and, for those submitted in 2027, as much as eight years from MISO's proposal, cannot address near-term resource adequacy or reliability needs. However, six years is the worst-case scenario, reflecting the maximum period for an ERAS generating facility to come online, which nevertheless is nearly half of the maximum 11-year commercial operation deadline that is used by some DPP interconnection requests.[217] Further, while there is no guarantee that all ERAS interconnection requests will achieve commercial operation, it is reasonable to conclude that ERAS interconnection requests are more likely to do so than DPP interconnection requests given the ERAS eligibility requirements designed to swiftly identify "shovel ready" projects. We agree with commenters that MISO's proposed coupling of its proposed commercial operation date requirements and stringent eligibility requirements will enable MISO to accelerate the study of urgently needed, "shovel ready" projects to help alleviate near-term resource adequacy needs.[218]

85. With respect to protester arguments that the proposed language in GIP section 3.9.8 may conflict with MISO's assertion that "[a]ll ERAS projects are eligible to

[215] Transmittal at 8.

[216] *See* MISO Answer at 6-7.

[217] Witmeier Testimony at 47.

[218] Transmittal at 39; MISO Answer at 29; AECS Comments at 4; Big Rivers Electric Comments at 3; CenterPoint Comments at 1; Entergy/Cleco/Cooperative Energy Comments at 9-10; ITC Comments at 3; Louisiana and Mississippi Commissions Comments at 5; Midwest TDUs Comments at 3-4; MISO TOs Comments at 3.

use the grace period of up to three years as documented in GIA Article 2.3.1,"[219] we note that GIP section 3.9.8 addresses modifications to the ERAS interconnection request, and not to the EGIA.

(c) RERRA Verification Requirement

86. Contrary to Clean Energy Associations' assertions,[220] we do not believe that MISO's proposed GIP section 3.9.1 is contradictory. Rather, we find that proposed GIP section 3.9.1.1.i provides requirements for the RERRA's written verification with respect to "new, incremental load" whereas proposed GIP section 3.9.1.1.ii provides requirements for the RERRA's written verification with respect to "a resource adequacy deficiency" with multiple means by which such a determination can be supported.

87. For example, under proposed GIP section 3.9.1.1.ii, MISO provides examples of supporting materials that "can" support a determination that the proposed interconnection request will address an identified resource adequacy need, including integrated resource plans.

88. In response to PIOs' concerns that nothing in the ERAS process requires a RERRA to consider whether a resource currently in the DPP is better suited to meet the identified need, we note that the DPP is a MISO-specific process outside of a RERRA's purview. Further, nothing prohibits an interconnection customer with an interconnection request in the DPP from participating in the ERAS process if it satisfies the ERAS eligibility requirements.

(d) Other ERAS Eligibility Requirements

89. As further discussed below, we find that MISO has sufficiently detailed the parameters of ERAS eligibility in the proposed Tariff, and MISO has narrowly tailored the Revised ERAS Proposal to the identified near-term resource adequacy or reliability needs.[221] Moreover, as for protester suggestions that the RERRA verification should incorporate a scoring mechanism or other alternative approaches, we reiterate our earlier finding that the Commission affords MISO considerable flexibility in addressing region-specific interconnection queue processing challenges, and we need not consider whether

[219] Transmittal at 50.

[220] Clean Energy Associations Protest at 11-12.

[221] *See* discussion *infra*, parts IV.B.2.c, 3.c., 4.c and 5.c.

MISO's proposal is more or less reasonable than the alternative solutions identified by protesters.[222]

2. Jurisdiction and Filed Rate Doctrine

a. MISO's Filing

90. MISO states that the FPA and Commission precedent recognize the authority of state regulators and their jurisdictional utilities to plan for adequate generation to address resource adequacy needs within their jurisdictional footprints.[223] MISO further states that the Revised ERAS Proposal incorporates the role of states and other RERRAs and "provides a vehicle for the RERRA to verify to MISO that there is a valid, new incremental load addition that is not incorporated in relevant plans or that the proposed Generating Facility will address an identified resource adequacy deficiency."[224] MISO's statement is a reference to the RERRA verification eligibility requirement in proposed GIP section 3.9.1, which provides that:

> 1. The Interconnection Request shall be accompanied by a written verification from the RERRA (or its documented representative) where the load to be served by the Generating Facility is located and, subject to the procedures the RERRA requires, that either:
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> a. The new, incremental load addition claimed by the interconnection customer is valid and not otherwise included in a resource plan or other process under the RERRA's purview; or
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> b. The generating facility proposed by the interconnection customer will address a resource adequacy deficiency as determined by the RERRA, state, LSE, or interconnection customer as supported by certain documentation; or
>
> c. For generating facilities that will address a resource adequacy deficiency and either serves retail load or a retail choice state, the interconnection customer will

[222] *See supra* P 82.

[223] Transmittal at 2.

[224] *Id.* at 9.

> indicate the specific load as required in the interconnection request and provide evidence that the generating facility will address a resource adequacy deficiency as described in (b), but such interconnection customer will not be required to include a written verification from the RERRA.

b. Responsive Pleadings

i. Comments in Support

91. Some commenters assert that ERAS aligns with state jurisdictional authority as it relates to decision-making on resource adequacy.[225] AECS notes that the process respects state authority over resource procurement and ensures that RERRAs will determine the resources necessary to support LSEs under their jurisdiction.[226] Louisiana and Mississippi Commissions assert that the verification process accommodates the needs of the various MISO states, both regulated and those with retail access.[227] MISO TOs state that, according to Commission precedent, states have authority over resource adequacy, and ERAS intentionally empowers states and RERRAs with the ability to signal to MISO, through the RERRA verification process, that certain projects need the expedited treatment of the ERAS process. Additionally, MISO TOs note that MISO added Tariff language incorporating the retail access states into the ERAS process to address resource adequacy deficiencies in those states, recognizing the structural differences in those states.[228] Texas Commission asserts that there is a need to study interconnection requests that are necessary to meet nearer-term, state-determined resource adequacy needs because there is an increasing risk of a state's "needs determination" being unmet if an interconnection request is delayed in MISO's queue.[229]

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[225] AECS Comments at 6; Entergy/Cleco/Cooperative Energy Comments at 3, 8; Louisiana and Mississippi Commissions Comments at 3, 9; MISO TOs Comments at 3, 10-11; Missouri Commission Comments at 2; Texas Commission Comments at 5-7.

[226] AECS Comments at 6.

[227] Louisiana and Mississippi Commissions Comments at 9.

[228] MISO TOs Comments at 10-11.

[229] Texas Commission Comments at 7.

ii. Protests

92. NextEra and MISO IPPs assert that the ERAS proposal unjustly and unreasonably allows states to set the terms and conditions of Commission-jurisdictional service, despite the FPA granting, and the courts upholding, exclusive jurisdiction over the rates, terms, and conditions for the transmission of electric energy in interstate commerce, including interconnection service, to the Commission.[230] Further, NextEra and MISO IPPs state that ERAS essentially grants RERRAs the authority to determine which interconnection customers will be granted interconnection service, which is a Commission-exclusive jurisdiction.[231] Additionally, NextEra asserts that MISO is required to provide nondiscriminatory open access to the transmission system in a manner that allows all resources to compete on equal footing, which will not infringe on states' authority over resource adequacy, so long as MISO does not mandate or prohibit any particular generating facility or resource mix.[232] In support of this, NextEra and MISO IPPs argue that the Commission rejected past proposals as unduly discriminatory when they prioritized resources that were being developed in connection with a state resource

[230] *See* NextEra Docket No. ER25-1674 Protest at 6, 48-49 (citing *FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260, 288 (2016); *Hughes v. Talen Energy Mktg., LLC*, 578 U.S. 150, 164 (2016) (*Talen*); and PJM RRI Order, 190 FERC ¶ 61,084 at P 75); MISO IPPs Docket No. ER25-1674 Protest, Affidavit of the Hon. Joseph T. Kelliher ¶ P 16 (Kelliher Aff.).

[231] MISO IPPs Docket No. ER25-1674 Protest at 13-14 (citing *FPL Energy Marcus Hook, L.P. v. FERC*, 430 F.3d 441, 443 (D.C. Cir. 2005); PJM RRI Order, 190 FERC ¶ 61,084 at P 75); NextEra Protest at 49.

[232] NextEra Docket No. ER25-1674 Protest at 50 (citing *Xcel Energy Operating Cos.*, 106 FERC ¶ 61,260, at P 23 (2004) (*Xcel*) (rejecting a proposal to provide priority queue access to interconnection requests that were part of a state-sponsored bidding process and finding that interconnection customers that did not take part in the state-sponsored bidding must be allowed to compete in the wholesale energy market on an equal footing); PJM RRI Order, 190 FERC ¶ 61,084 at P 76).

solicitation process[233] and rejected the RERRA exclusion in the 2023 MISO Queue Cap Proposal.[234]

93. NextEra asserts that, due to the non-delegation doctrine, neither MISO nor the Commission can delegate authority over the rates, terms, and conditions of interconnection service to RERRAs.[235] NextEra argues that there is a presumption against subdelegation, even if that subdelegation is to a state commission, which may be a RERRA under the ERAS process.[236] NextEra asserts that RERRAs are not subject to Commission oversight, so it is not clear that the Commission can exercise oversight of RERRA rates via FPA section 206[237] complaint proceedings, which would violate the non-delegation doctrine and the FPA.[238] Clean Energy Associations argue that "MISO is effectively delegating to states its responsibility for ensuring that its own Tariff is not unduly discriminatory or preferential, and thereby leaving the Commission without oversight."[239] Additionally, Clean Energy Associations state that MISO has failed to

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[233] MISO IPPs Docket No. ER25-1674 Protest at 7-8 (citing *Sw. Power Pool, Inc.*, 147 FERC ¶ 61,201, at P 124 (2014)); NextEra Docket No. ER25-1674 Protest at 8 (citing *Xcel*, 106 FERC ¶ 61,260 at PP 12-13, 22-24); *Midwest Indep. Transmission Sys. Operator, Inc*., 124 FERC ¶ 61,183, at P 143 (2008)).

[234] NextEra Docket No. ER25-1674 Protest at 9 (citing January 2024 Order, 186 FERC ¶ 61,054 at PP 176-177).

[235] *Id.* at 53.

[236] *Id.* (citing *U.S. Telecom Ass'n v. FCC*, 359 F.3d 554, 566 (D.C. Cir. 2004) (*U.S. Telecom*); *Texas v. Rettig*, 987 F.3d 518, 531 (5th Cir. 2021)); *see also* MISO IPPs Docket No. ER25-1674 Protest at 15 (citing Kelliher Aff. at 6-7).

[237] 16 U.S.C. § 824e.

[238] NextEra Docket No. ER25-1674 Protest at 53-54 (citing *La. Pub. Serv. Comm'n v. FERC*, 761 F.3d 540, 552 (5th Cir. 2014) (*Louisiana PSC*); *see Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Servs. by Pub. Utils.; Recovery of Stranded Costs by Pub. Utils. & Transmitting Utils.*, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996) (cross-referenced at 75 FERC ¶ 61,080), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 (cross-referenced at 78 FERC ¶ 61,220), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Pol'y Study Grp. v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. N.Y. v. FERC*, 535 U.S. 1.

[239] Clean Energy Associations Docket No. ER25-1674 Protest at 22.

meet its obligations as an independent system operator under Order No. 888 to ensure fair and non-discriminatory access to transmission services and ancillary service for all users of the transmission system.

94. Finally, NextEra and MISO IPPs assert that ERAS violates the filed rate doctrine because a RERRA will establish the criteria used to determine ERAS participation without filing with the Commission and without providing uniform, objective, and non-discriminatory criteria in the tariff, which will circumvent the Commission's jurisdictional authority to ensure that the terms and conditions of receiving interconnection service in MISO are just and reasonable and not unduly discriminatory or preferential.[240] NextEra additionally argues that the fact that RERRAs can set their own criteria for resources to enter ERAS also will result in similarly situated interconnection customers within the MISO region being subject to arbitrary differences in the terms and conditions of interconnection service, depending on its applicable RERRA.[241] NextEra further argues that interconnection customers will not receive notice of the terms and conditions of the RERRA's criteria, as the FPA requires.[242] MISO IPPs assert that a lack of objective criteria in the Tariff will create an environment ripe for undue discrimination in the RERRA approval process, and thus the composition of the ERAS queue.[243]

95. Clean Grid Alliance argues that MISO's discussion of jurisdiction is intended to divert attention from the deficiencies in the Revised ERAS Proposal and that, while RERRAs should have a role over resource adequacy, MISO must still comply with open access requirements.[244] Similarly, COMPP asserts that though resource adequacy decisions rest within state jurisdiction, MISO's role is to meet the Commission's reliability standards while adhering to open access principles, and such principles are not being met by the Revised ERAS Proposal.[245] PIOs argue that MISO's refusal to exert

[240] MISO IPPs Docket No. ER25-1674 Protest at 14; NextEra Docket No. ER25-1674 Protest at 52.

[241] NextEra Docket No. ER25-1674 Protest at 17-18.

[242] *Id.* at 52-53.

[243] MISO IPPs Docket No. ER25-1674 Protest at 15 (citing Kelliher Aff. at 6-7).

[244] Clean Grid Alliance Protest at 30.

[245] COMPP Protest at 7-8.

any oversight over the RERRA authority continues to go "beyond appropriate respect" for states' role in resource adequacy.[246]

iii. Answers

(a) MISO Answer

96. MISO asserts that the Revised ERAS Proposal reflects and respects the unique jurisdictional divide between the states, MISO, and the federal government. MISO reiterates that it is the states, not MISO, that have the power to determine the resources that will be used in states' jurisdictions.[247] MISO asserts that because there are a wide variety of RERRAs, it was required to design a flexible enough process to accommodate this variety. MISO argues that the additional eligibility requirements ensure that there are uniform, objective criteria in the Tariff.[248] MISO contends that states are not setting the rates, terms, and conditions of interconnection service; rather, RERRAs determine need within their jurisdictional processes, and that regardless of that determination, ERAS interconnection requests will still need to go through the approval process outside of ERAS.[249]

c. Commission Determination

97. We disagree with protesters that the Revised ERAS Proposal intrudes upon the Commission's exclusive FPA jurisdiction over generator interconnection. We disagree that the precedent cited by protesters indicates that the role of states, as RERRAs, in the ERAS process is impermissible.

98. Specifically, NextEra points to *Talen* to argue that even if states have authority over generating facilities, that does not permit them to "exercise control over the terms and conditions of interconnection service."[250] In *Talen*, incumbent generators brought suit to challenge a Maryland Public Service Commission (Maryland Commission) order that required LSEs in Maryland to buy capacity from a specific generator and pay the difference between the Commission-jurisdictional PJM interstate wholesale capacity auction clearing price and a price that the Maryland Commission guaranteed. The

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[246] PIOs Protest at 24 (quoting May 2025 Order, 191 FERC ¶ 61,13 (See, Comm'r, consenting at P 6)).

[247] MISO Answer at 4, 22, 25-26, 30.

[248] MISO Docket No. ER25-1674 Answer at 15.

[249] *Id.* at 16.

[250] NextEra Docket No. ER25-1674 Protest at 50 (citing *Talen*, 578 U.S. at 164).

Supreme Court of the United States (Supreme Court) rejected the Maryland program, stating that "[b]y adjusting an interstate wholesale rate, Maryland's program invades FERC's regulatory turf."[251] The Supreme Court stated that "[s]tates may not seek to achieve ends, however legitimate, through regulatory means that intrude on FERC's authority"[252] and that states "interfere with FERC's authority by disregarding interstate wholesale rates FERC has deemed just and reasonable, even when [s]tates exercise their traditional authority over . . . in-state generation."[253] The Supreme Court went on to say, however, that "[n]othing in this opinion should be read to foreclose . . . [s]tates from encouraging production of new or clean generation through measures 'untethered to a generator's wholesale market participation.'"[254]

99. We find that the Revised ERAS Proposal is permissible under *Talen* because RERRA participation in the ERAS process would be wholly pursuant to a Commission-jurisdictional process (i.e., the generator interconnection process), proposed by MISO and approved by the Commission—not by state authorities—and under which a GIP is on file with the Commission and any future revisions would be subject to Commission approval. Further, the ERAS process would remain subject to the Commission's authority pursuant to FPA sections 205 and 206. In contrast, in *Talen*, the Maryland Commission established a state program that operated outside a Commission-jurisdictional process and "interfered" with the Commission's authority to establish interstate wholesale rates. Nothing in the Revised ERAS Proposal deprives the Commission of its statutory jurisdiction as it applies to generator interconnection.

100. Similarly, we disagree with MISO IPPs' claim that, based on *U.S. Telecom*, the Revised ERAS Proposal impermissibly requires the Commission to subdelegate its FPA authority to the RERRAs. In that decision, which involved the Federal Communications Commission's (FCC) subdelegation to state commissions certain determinations that the FCC was required to make pursuant to the Telecommunications Act of 1996,[255] the United States Court of Appeals for the District of Columbia Circuit determined that the

[251] *Talen*, 578 U.S. at 163.

[252] *Id.* at 164.

[253] *Id*. at 165.

[254] *Id.* at 166.

[255] 47 U.S.C. § 151 *et seq.*

FCC's subdelegation had, in some respects, given the state commissions "unlimited discretion."[256]

101. We find that *U.S. Telecom* is distinguishable from the Revised ERAS Proposal. The Revised ERAS Proposal does not subdelegate the Commission's authority but simply creates a role for RERRAs in a Commission-jurisdictional process.[257] In particular, the RERRA's role would be limited to assessing and verifying non-speculative interconnection requests that address an identified resource adequacy deficiency. In this way, the Revised ERAS Proposal also recognizes the states' jurisdictional authority over resource planning and the generation mix within their boundaries. Further, in *Louisiana PSC*, the United States Court of Appeals for the Fifth Circuit determined that it is not an unlawful subdelegation for the Commission to incorporate state-determined rate elements in Commission-jurisdictional rate proceedings.[258] According to the court, the Commission's "continuing review in Section 206 proceedings distinguishes it from the unease expressed in [*U.S.*] *Telecom,* of agencies' 'vague or inadequate assertions of final reviewing authority.'"[259] Similarly, under the Revised ERAS Proposal, the RERRA is given a limited role in verifying interconnection requests, and such requests, through the EGIA process, would be subject to Commission review under FPA sections 205 and 206.

102. We also disagree with NextEra and MISO IPPs that the Revised ERAS Proposal violates the filed rate doctrine. The filed rate doctrine and the rule against retroactive ratemaking are "the statutory requirements that bind regulated entities to charge only the rates filed with [the Commission] and to change their rates only prospectively."[260] The FPA requires public utilities to file with the Commission the rates, terms, and conditions

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[256] *U.S. Telecom*, 359 F.3d at 564.

[257] *See, e.g.*, *Participation of Distributed Energy Res. Aggregations in Mkts. Operated by Reg'l Transmission Orgs. & Indep. Sys. Operators*, Order No. 2222, 172 FERC ¶ 61,247, at P 64 (2020) (finding that small utilities may not participate in distributed energy resource aggregations unless the RERRA affirmatively allows such customers to participate in distributed energy resource aggregations), *order on reh'g*, Order No. 2222-A, 174 FERC ¶ 61,197, *order on reh'g*, Order No. 2222-B, 175 FERC ¶ 61,227 (2021).

[258] *Louisiana PSC*, 761 F.3d at 551-52 (holding that there was no unlawful subdelegation where the Commission exercised its role by reviewing and accepting a bandwidth formula that incorporated state agencies' depreciation rates).

[259] *Id*. at 552 (quoting *U.S. Telecom*, 359 F.3d at 568).

[260] *Okla. Gas & Elec. Co. v. FERC*, 11 F.4th 821, 829 (D.C. Cir. 2021); *see also PJM Power Providers Grp. v. FERC*, 96 F.4th 390, 394 (3rd Cir. 2024).

of the jurisdictional service they provide.[261] NextEra and MISO IPPs argue that the Revised ERAS Proposal violates the filed rate doctrine because it allows RERRAs to establish criteria that would not be on file with the Commission and that would determine whether or not an interconnection request is eligible for ERAS.[262] We disagree. We find that the Revised ERAS Proposal does not present a filed rate doctrine concern because it provides adequate notice of the ERAS eligibility requirements, including the RERRA verification requirement.[263] In particular, the RERRA verification requirement in proposed GIP section 3.9.1.1 has multiple sub-requirements that provide a level of uniformity among RERRAs, such as the requirement that the RERRA must be from the same location as the load to be served, and the requirement that the RERRA verification must include an explanation of how the generating facility associated with the interconnection request will address a resource adequacy need, among other things.[264] If the RERRA verification does not satisfy these requirements, then the interconnection request would not be eligible for ERAS. Thus, we find that MISO has sufficiently detailed the parameters of ERAS eligibility, including the RERRA verification requirement, to satisfy the filed rate doctrine.

3. ERAS Requirements and Open Access/Undue Discrimination Concerns

a. MISO's Filing

i. RERRA Verification

103. As noted above, MISO proposes to require that to qualify for ERAS, an interconnection request must include a written verification from the RERRA, or RERRA representative where the load to be served by the generating facility is located, that requires either:

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[261] 16 U.S.C. § 824d(c); *see* 18 C.F.R. § 35.1(a) (2024) (requiring that any "rates and charges . . . classifications, practices, rules and regulations affecting such rates, charges, classifications, services, rules, regulations or practices," be filed with the Commission).

[262] *See* MISO IPPs Docket No. ER25-1674 Protest at 14; NextEra Docket No. ER25-1674 Protest at 51-53.

[263] *See, e.g.*, *Consol. Edison Co. of N.Y. v. FERC*, 347 F.3d 964, 969 (D.C. Cir. 2003); *Columbia Gas Transmission Corp. v. FERC*, 895 F.2d 791, 795-97 (D.C. Cir. 1990).

[264] MISO, Proposed Tariff, attach. X (GIP) (175.0.0), § 3.9.1.

a. The new, incremental load addition claimed by the interconnection customer is valid and not otherwise included in a resource plan or other process under the RERRA's purview; or

b. The generating facility proposed by the interconnection customer will address a resource adequacy deficiency as determined by the RERRA, state, LSE, or interconnection customer, which can be supported by: (i) a state energy forecast, or other forward-looking forecast; (ii) commencement of a state proceeding; (iii) review of a RERRA, LSE, or other state resource plan or document, which may include, but is not limited to: integrated resource plans, procurement plans, or other plan or study types; (iv) response to a request for proposals; or (v) other process, or delegation of authority, as determined by the RERRA or RERRA regulations (including in retail choice states).

For generating facilities that will address a resource adequacy deficiency and either serve retail load or a retail choice state, the interconnection customer will not be required to include a written verification from the RERRA. Instead, the interconnection customer will indicate the specific load as required in the interconnection request and provide evidence that the generating facility will address a resource adequacy deficiency as described in (b).

104. MISO states that it changed this requirement, from the RERRA notification in the Initial ERAS Proposal,[265] to better target the resource adequacy driver that an ERAS interconnection request addresses and to ensure that the RERRA verifies that such interconnection request will address a new load addition or a resource adequacy deficiency in its footprint.[266] MISO further states that the revised requirement is critical to maintaining the limited scope of ERAS to address near-term resource adequacy and/or reliability need claimed by an interconnection customer in a RERRA. MISO explains

[265] In the Initial ERAS Proposal, MISO proposed to require that an ERAS interconnection request be accompanied by a written notification from the RERRA specifying where the load to be served is located and that the interconnection request should be included in ERAS.

[266] Transmittal at 30.

that the RERRA verification may take any form so long as it is made by the RERRA or RERRA representative.

105. MISO states that the third option related to the RERRA verification was added to incorporate retail choice states – Illinois and a portion of Michigan.[267] Under this option, rather than requiring RERRA verification, MISO proposes to notify the respective RERRA that an ERAS interconnection request was submitted and provide a copy of the interconnection request. MISO states that the RERRA will have 10 business days from the date of notification to state that the interconnection request should not be included in ERAS. MISO states that this aspect of its proposal recognizes that interconnection customers in retail choice states do not need to seek approval from a RERRA and that there are alternative retail electric suppliers that serve load. MISO asserts that this language better facilitates the use of ERAS in Illinois and the retail choice areas of Michigan without changing the role or requirements for RERRAs in other parts of MISO's footprint.

106. MISO asserts that it is not a resource planner, so it is reasonable to require a RERRA verification for consideration in the ERAS process.[268] MISO explains that, in fact, the FPA recognizes that the RERRAs have jurisdiction over resource adequacy needs.[269] Therefore, MISO states that including the RERRA verification requirement ensures that an ERAS interconnection request is tied to a specific resource adequacy or reliability need.[270] MISO adds that this requirement will prohibit the submission of speculative interconnection requests with no connection to a specific need.[271] MISO states, however, that the RERRA verification requirement is not intended to constitute a final determination on the need or suitability of the interconnection request. Rather, MISO emphasizes that the RERRA verification is only a condition for requesting that MISO study a proposed interconnection request in the ERAS process.[272]

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[267] *Id.* at 31.

[268] Witmeier Testimony at 31.

[269] Transmittal at 2 (citing 16 U.S.C. § 824; *CXA La Paloma, LLC v. Cal. Indep. Sys. Operator Corp.*, 165 FERC ¶ 61,148, at P 70 (2018)).

[270] *Id.* at 30.

[271] Witmeier Testimony at 32. MISO states that verification is only needed from one RERRA for an application for ERAS participation. *Id.* at 35.

[272] Transmittal at 31, 52.

107. MISO states that due to its unique composition of almost entirely vertically integrated utilities, resource adequacy decisions must be made in collaboration with the states.[273] MISO explains that responsibility for addressing resource adequacy or reliability needs is a state responsibility and that it would be inappropriate for MISO to make selections to address these needs. MISO states that the Revised ERAS Proposal accounts for its unique composition and the division of jurisdictional authority by proposing that MISO only facilitate the ERAS process and that interconnection customers identify the specific needs their interconnection requests address, and that RERRAs (including states) verify to MISO which interconnection requests merit expedited study.

ii. Executed Agreement Requirement

108. MISO also proposes to require an ERAS interconnection customer to have an executed agreement evidencing that its interconnection request "is intended to be used by the entity with the claimed resource adequacy or reliability need" (executed agreement requirement).[274] MISO proposes that the required agreement can take the form of: (1) an LSE acknowledgement to self-supply; (2) a power purchase agreement (PPA) or a similar off-take agreement between the ERAS interconnection customer and the entity to be served (including, but not limited to, an alternative retail electric supplier or its LSE); (3) an agreement that provides for the transfer of ownership or control of the generating facility to the entity with the load to be served (including, but not limited to, an alternative retail electric supplier or its LSE) after such generating facility is developed by the interconnection customer; or (4) an "other" agreement between the ERAS interconnection customer and the entity with the load to be served (including, but not limited to, an alternative retail electric supplier or its LSE), stating that the ERAS interconnection request will be used to meet an identified resource adequacy deficiency.[275]

109. MISO states that this requirement will ensure that an ERAS interconnection request is intended to be used by the entity with the claimed resource adequacy or reliability need.[276] MISO explains that such a requirement prevents speculative interconnection requests with no commercial arrangements from participating in ERAS.

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[273] *Id.* at 19.

[274] *Id.* at 30; Witmeier Testimony at 39, 41; MISO, Proposed Tariff, attach. X (GIP) (175.0.0), § 3.9.1.2.

[275] Transmittal at 30-31; MISO, Proposed Tariff, attach. X (GIP) (175.0.0), § 3.9.1.2.

[276] Transmittal at 30.

MISO states that, for example, an interconnection customer that has an agreement with a data center developer for the generation to serve that load is differently situated from an interconnection customer that enters the queue with the hope of pitching their generation project to the developer. MISO adds that, based on stakeholder feedback, it expanded the ERAS process to allow independent power producers to participate through inclusion of an "other" type of executed agreement.[277] MISO asserts that the executed agreement requirement mitigates overuse concerns because it pairs an ERAS interconnection request with a specific need.[278]

iii. ERAS Cap and Carve Outs

110. MISO proposes to establish a limit on the total number of interconnection requests that can participate in the ERAS process to 68. Of the 68 total interconnection requests, MISO proposes to allow a maximum of 10 interconnection requests from independent power producers that have agreements with entities other than LSEs and a maximum of 8 interconnection requests to serve retail choice load.[279] MISO states that the remaining 50 interconnection requests allowed to participate in ERAS will be for the remaining applicants for non-retail choice states. In addition, MISO proposes to implement a limit on the total number of interconnection requests that may be studied in an ERAS quarterly study period to 10 interconnection requests. MISO states that the interconnection requests will be selected based on the time stamp of submission, and it will create a waitlist for interconnection requests beyond the tenth submission. MISO further states that it will screen the submitted interconnection requests to ensure that none are in the same geographical area or impacting the same constraint. MISO states that, if any of the interconnection requests are in the same geographical area or impact the same constraint, then the one with a later time submission will be deferred to the next available ERAS quarterly study period. MISO explains that in the event that an interconnection request is deferred to a future ERAS quarterly study period, it will review any ERAS interconnection requests on the waitlist to determine whether one can be moved up into the deferred interconnection request's spot. Accordingly, MISO states that it will confirm that an interconnection request from the waitlist is not in the same geographic area as those in the ERAS quarterly study period under review. MISO states that these proposed limitations are in response to the Commission's feedback in the May 2025 Order.

111. MISO states that these proposed limitations will enable MISO to complete the ERAS process more efficiently and will result in interconnection customers receiving an

[277] *Id.* at 41.

[278] *Id.* at 31.

[279] *Id.* at 25-26; MISO, Proposed Tariff, attach. X (GIP) (175.0.0), § 3.9.2.

EGIA quickly. MISO further states that the proposed limitations will allow MISO to better plan for the number of interconnection requests requiring study each quarterly study period and to better coordinate internal resources.[280] MISO states that while it stands by its original assertions that the ERAS process will not affect DPP interconnection requests and that the strict eligibility requirements will limit interconnection request submissions, expressly capping the number of interconnection requests will further ensure that DPP interconnection customers are not harmed by the ERAS process.[281] MISO asserts that its proposed cap serves the same goal as PJM's RRI, to "reasonably balance the need to address … resource adequacy challenges with the need to avoid an influx of projects that could overwhelm … [MISO's] interconnection process," but that MISO's proposal is spread over a longer period of time than PJM's RRI in order to allow prospective interconnection customers time to fully prepare their interconnection requests.[282]

iv. Other ERAS Eligibility Requirements

112. MISO proposes several requirements for ERAS interconnection requests, in addition to the demonstrations discussed above. Specifically, MISO proposes that interconnection customers must provide a non-refundable $100,000 D1 application fee and a refundable M2 amount of $24,000/MW and meet a requirement for 100% site control for both the generating facility and interconnection customer's interconnection facilities.[283]

113. MISO states that the non-refundable $100,000 D1 application fee, which is higher than the $5,000 D1 amount (even as adjusted for inflation) in the DPP, is necessary to prevent speculative interconnection requests from applying to the ERAS process, implement the temporary ERAS process, and cover costs associated with processing ERAS interconnection requests.[284] MISO states that the M2 amount of $24,000/MW (relative to $8,000/MW in the DPP) is based on MISO's existing provisional interconnection service milestone requirements and represents the same level of upfront financial commitment for this "one phase" process that an interconnection customer otherwise would make cumulatively for the "three phase" M2, M3, and M4 milestones in

[280] Transmittal at 26.

[281] *Id.* at 27.

[282] *Id.*

[283] *Id.* at 36.

[284] *Id.* at 49.

the DPP process.[285] MISO adds that in addition to the RERRA verification and executed agreement requirements, the milestone payments and deposits are required at the time of application to allow MISO to complete the ERAS process within the estimated 90-day timeframe.[286]

114. MISO states that it is reasonable to require 100% site control for both the generating facility and interconnection customer's interconnection facilities for ERAS interconnection requests because it ensures that MISO will not be inundated with speculative interconnection requests. MISO explains that this requirement is more stringent than the requirements for the DPP, which only requires a 100% site control demonstration for the generating facility and a 50% demonstration of site control for interconnection customer's interconnection facilities at the time of an application submission. MISO also asserts that its proposal to disallow financial security in lieu of the proposed site control requirements will deter speculative interconnection requests because it prohibits such requests from being eligible for the ERAS process if they are unable to obtain necessary permits or siting requirements.[287]

115. MISO proposes to require that an ERAS interconnection request identify the claimed resource adequacy and/or reliability need for which the interconnection request is being submitted.[288] MISO states that this must include the location of the generating facility, i.e., the county and state of the proposed generating facility, the electrical bus location(s), and the Local Resource Zone. MISO states that the ERAS interconnection request must identify the expected peak demand for electricity in MW over any one hour period and that the requested level of interconnection service must not exceed 150% of the identified MW need.

116. MISO states that it plans to publish an ERAS webpage that will include a significant amount of information related to each ERAS interconnection request.[289] MISO states that ERAS applications must include a non-confidential summary of the information contained in the interconnection requests for MISO to publish on its website. The summary will include the interconnection customer proposing the generating facility, the MW range of need that the ERAS interconnection request will address, the Local Resource Zone where the proposed generating facility will be located, and a general

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[285] *Id.*; Witmeier Testimony at 45.

[286] Transmittal at 50.

[287] *Id.* at 59; Witmeier Testimony at 46.

[288] Transmittal at 34; MISO, Proposed Tariff, attach. X (GIP) (175.0.0), § 3.3.1.

[289] Transmittal at 34; Witmeier Testimony at 38-39.

description of the driver for the load need (e.g., a data center, manufacturing plant, etc.).[290] MISO states that in addition to the non-confidential summary, it will publish the RERRA that submitted a verification for each ERAS interconnection request, the specific group that the ERAS interconnection request falls within (i.e., LSE, independent power producer, or retail choice), and the specific ERAS quarterly study period in which the ERAS interconnection request will be studied once MISO has completed the screening process for each ERAS quarterly study period. Finally, MISO states that it plans to publish an information guide for potential ERAS interconnection customers that addresses common questions and problems that prospective ERAS interconnection customers may face.[291] MISO states that these additional requirements will increase the transparency of the ERAS process.

b. Responsive Pleadings

i. Comments in Support

117. Commenters argue that the Revised ERAS Proposal maintains open access[292] and is not unduly discriminatory or preferential.[293] As evidence of this, commenters raise several points regarding the Revised ERAS Proposal, including: (1) there are ERAS slots reserved specifically for independent power producers;[294] (2) projects that do not meet ERAS requirements or are not identified by the RERRA as necessary for resource adequacy may still proceed through the DPP;[295] and (3) DPP interconnection requests can

[290] Transmittal at 34.

[291] *Id.* at 34-35.

[292] AECS Comments at 8; Big Rivers Electric Comments at 7; Consumers Energy Comments at 3; Entergy/Cleco/Cooperative Energy Comments at 13; ITC Comments at 5; Louisiana and Mississippi Commissions Comments at 8; MISO TOs Comments at 19; Missouri Commission Comments at 3-4; NIPSCO Comments at 8; Texas Commission Comments at 12.

[293] AECS Comments at 8; Big Rivers Electric Comments at 7; Consumers Energy Comments at 3; Louisiana and Mississippi Commissions Comments at 8; MISO TOs Comments at 17; Missouri Commission Comments at 3; NIPSCO Comments at 8; Texas Commission Comments at 9.

[294] AECS Comments at 8; Arkansas Commission Comments at 3; Big River Electric Comments at 8; Duke Energy Indiana Comments at 2; Entergy/Cleco/Cooperative Energy Comments at 13; MISO TOs Comments at 16-17.

[295] AECS Comments at 8.

transfer to ERAS.[296] Commenters also argue that ERAS is open to all project sponsors, and fuel and technology types, so long as the interconnection request satisfies the ERAS requirements.[297]

118. Commenters assert that with the revisions to require RERRA verification and the identification of a specific need in the same Local Resource Zone as the ERAS interconnection request, MISO's Revised ERAS Proposal is a just and reasonable solution to MISO's resource adequacy and reliability concerns.[298] Several commenters argue that the RERRA verification process reasonably balances MISO's need to verify projects that meet resource adequacy needs.[299] Further, Louisiana and Mississippi Commissions assert that the RERRA verification reasonably balances, "the state's need to not prejudge generation certifications."[300] Michigan Commission states that it supports MISO's proposed limit to study 10 interconnection requests per quarterly study period, the RERRA verification, and the other eligibility requirements for interconnection requests to participate in ERAS.[301] Michigan Commission adds that the executed agreement requirement provides a direct linkage from the resource adequacy need to the ERAS interconnection request.

119. Midwest TDUs state that they appreciate that the Revised ERAS Proposal will be implemented in a manner that allows municipal joint action agencies to meaningfully participate.[302] Midwest TDUs assert that joint action agencies can submit notifications as the documented representative of their municipal utility member RERRAs, consistent

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[296] Big River Electric Comments at 8; Louisiana and Mississippi Commissions Comments at 8.

[297] AECS Comments at 8; Arkansas Commission Comments at 3; Big Rivers Electric Comments at 8; Consumers Energy Comments at 3; Entergy/Cleco/Cooperative Energy Comments at 13; Louisiana and Mississippi Commissions Comments at 8; MISO TOs Comments at 17; NIPSCO Comments at 8.

[298] Big Rivers Electric Comments at 8; NIPSCO Comments at 7-8.

[299] Louisiana and Mississippi Commissions Comments at 10; Otter Tail Comments at 4; Texas Commission Comments at 8.

[300] Louisiana and Mississippi Commissions Comments at 10.

[301] Michigan Commission Protest at 7-9.

[302] Midwest TDUs Comments at 4.

with applicable laws and governance documents.[303] Midwest TDUs state that this provides assurance that they will not be foreclosed from, or unduly disadvantaged in, the ERAS process, which could be crucial to meeting their municipal utility members' resource adequacy and reliability needs.

120. Several commenters state that the Local Resource Zone requirement tightly ties the generating facility to the resource adequacy or reliability need.[304] Entergy, Cleco, and Cooperative Energy argue that the proposed requirement that resources be located in the same local resource zone as the associated resource adequacy or reliability need and the proposed limitation on the amount of interconnection service that may be requested through an ERAS interconnection request, providing reassurance that the ERAS interconnection requests studied by MISO will be limited to those that can meet anticipated generation capacity shortfalls.[305] AECS notes that the local resource zone requirement ensures that generating facilities can actually serve the load.[306]

121. Several commenters assert that the proposed cap on the number of ERAS interconnection requests that can studied for the entirety of the program and proposed cap on the number of interconnection requests that can be studied quarterly will better ensure that MISO studies interconnection requests in an accelerated time frame.[307] Commenters also note that the addition of a fixed "sunset date" ensures that ERAS is a temporary measure to address near-term resource adequacy needs.[308]

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[303] *Id.* at 7.

[304] AECS Comments at 5; Entergy/Cleco/Cooperative Energy Comments at 12; Louisiana and Mississippi Commissions Comments at 9.

[305] Entergy/Cleco/Cooperative Energy Comments at 12-13.

[306] AECS Comments at 5-6.

[307] AECS Comments at 7; Arkansas Commission Comments at 3; Consumers Energy at 3; Duke Energy Indiana Comments at 2; Entergy/Cleco/Cooperative Energy Comments at 9; MISO TOs Comment at 14; NIPSCO Comments at 8; Ottertail Comments at 4-5; Texas Commission Comments at 9-11; Wisconsin Utilities Comments at 4.

[308] Entergy/Cleco/Cooperative Energy Comments at 10; Otter Tail Comments at 4.

ii. Protests

(a) RERRA Verification Requirement

122. Protesters assert that the proposed Tariff, similar to the Initial ERAS Proposal, continues to lack any objective or transparent criteria to be used for the RERRA verification process and that it is not clear what would justify MISO's acceptance or rejection of ERAS submissions.[309] Michigan Commission argues that absent minimal RTO/ISO-level guardrails against discriminatory treatment and favoritism of certain projects over others, each RERRA must attempt to run its own screening process with incomplete information and without assistance from the RTOs/ISOs.[310] EPSA similarly argues that the proposed RERRA verification process gives RERRAs "significant power to delay [independent power producer] ERAS projects – or block them entirely in favor of ERAS submissions from the LSE in their respective service territory."[311]

123. Invenergy requests that MISO provide clarification on various proposed Tariff provisions, including the GIP section 3.9.1(ii) provision to explain what constitutes "other processes" or which among the LSE, RERRA, or interconnection customer is responsible to determine the resource adequacy need.[312] Invenergy also requests that MISO clarify what constitutes an "other agreement" under the executed agreement requirement because, without clarity, a RERRA could decide on its own accord what type of agreement qualifies.[313] Invenergy also states that MISO should clarify whether an ERAS interconnection customer keeps its EGIA if the agreement with the off-taker falls through.

124. With respect to the RERRA verification and retail choice, Michigan Commission strongly urges the removal of the proposed Tariff language stating that the RERRA verification can be supported by "a state energy forecast, or other forward-looking forecast."[314] According to Michigan Commission, this Tariff provision, in addition to

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[309] EPSA Comments at 3-4; Invenergy Protest at 3-5; Michigan Commission Protest at 11-12.

[310] Michigan Commission Protest at 11.

[311] EPSA Comments at 6.

[312] Constellation Protest at 6.

[313] Invenergy Protest at 7-8.

[314] Michigan Commission Protest at 16 (citing MISO, Proposed Tariff, attach. X (GIP) (175.0.0), § 3.9.1.1.ii.a).

being unnecessary, would allow nearly any project to be eligible for ERAS as long as there is some forecast to support it. Constellation argues that RERRAs are provided an unworkable and standardless veto power in retail choice states.[315]

125. Several protesters argue that the Revised ERAS Proposal, like the Initial ERAS Proposal before it, discriminates against independent power producers, and that additional time is required for independent power producers to meet the ERAS participation requirements.[316] Clean Grid Alliance argues that MISO's proposed carve out for independent power producers does not solve the discriminatory and preferential design of ERAS because MISO's proposal maintains its dependence on RERRA "validation."[317] Michigan Commission argues that the incumbent utilities' advantage over independent power producers results in inappropriately overburdening the RERRAs.[318] MISO IPPs assert that the Revised ERAS Proposal is distinguishable from the PJM RRI, which did not treat similarly situated interconnection customers differently.[319]

126. Vistra and COMPP assert that independent power producers contracting with customers other than LSEs will require additional time to meet the participation requirements compared to vertically integrated utilities in regulated states that already have participation documents and RERRA approvals in place.[320] According to Vistra, it will be extremely difficult for independent power producers to submit all required information and receive RERRA approval in the timeframe necessary to participate in the first ERAS quarterly study period, which begins on September 1, 2025. Vistra argues, among other things, that states are not similarly situated in their capacity to respond to the new verification requirements for independent power producer interconnection requests, and that it is possible that all 10 carve out slots are immediately filled by interconnection requests in the handful of states that are best positioned to implement the verification

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[315] Constellation Protest at 5.

[316] Clean Energy Associations Protest at 13-16; Clean Energy Associations Docket No. ER25-1674 Protest at 22, 43-44; Clean Grid Alliance Protest at 25, 63, 70, 72-78; COMPP Protest at 8-9; EPSA Protest at 4-6; MISO IPPs Docket No. ER25-1674 Protest at 9; NextEra Docket No. ER25-1674 Protest at 15-17; PIOs Protest at 5-9; PIOs Docket No. ER25-1674 Protest at 9-10; Vistra Protest at 6, 9-11.

[317] Clean Grid Alliance Protest at 25.

[318] Michigan Commission Protest at 10-11.

[319] MISO IPPs Docket No. ER25-1674 Protest at 8 (citing Kelliher Aff. at 3).

[320] COMPP Protest at 8; Vistra Protest at 6.

requirements quickly.[321] Vistra and COMPP propose that the initial independent power producer carve out application window begin in alignment with the second study period, starting on December 1, 2025.[322] Alternatively, COMPP requests that MISO reserves at least two study slots for independent power producers per ERAS cycle starting in December 2025.[323]

127. Similarly, Clean Grid Alliance asserts that LSEs have long-standing relationships with RERRAs while independent power producers do not, and this provides LSEs with an advantage in accessing ERAS. Clean Grid Alliance contends that LSE interconnection requests and independent power producer interconnection requests are similarly situated but that MISO's proposed carve out is evidence that ERAS caters to LSE participation.[324] Clean Grid Alliance further contends that, if MISO intended for independent power producers and LSEs to compete on equal footing, it would allow an equal number of spots for independent power producer ERAS interconnection requests and LSE ERAS interconnection requests.[325]

128. EPSA argues that it is often not possible for retail choice LSEs to indicate the specific load it will serve due to the nature of their agreements that often supply loads through a portfolio approach.[326] EPSA also states that competitive retailers often undertake a "demonstration of need" for corporate risk and hedging purposes to compare existing and expected future contractual obligations to load with the physical positions and market exposure of the LSE.[327] Accordingly, EPSA argues that MISO should clarify that an interconnection request that asserts the need for physical hedging of risks through

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[321] Vistra Protest at 10.

[322] *Id.* at 6, 9-11; COMPP Protest at 9.

[323] COMPP Protest at 9.

[324] Clean Energy Associations Docket No. ER25-1674 Protest at 17-18 (citing Order No. 2003, 104 FERC ¶ 61,103 at P 12); Clean Grid Alliance Protest at 24-25, 74, 78 (citing Order No. 2003, 104 FERC ¶ 61,103 at P 696); *see also* PIOs Docket No. ER25-1674 Protest at 9-10 (citing *Transmission Access Pol'y Study Grp. v. FERC*, 225 F.3d at 684).

[325] Clean Grid Alliance Protest at 26.

[326] EPSA Comments at 8-9.

[327] *Id.*

the addition of a resource is sufficient to meet the forward-looking forecast option contemplated in the proposed Tariff language.

129. PIOs argue that the Revised ERAS Proposal's selection criteria may make it challenging for merchant generators to benefit from ERAS interconnection service. PIOs allege that the proposal's requirement for merchant generators, such as independent power producers seeking to serve retail choice markets, to indicate the specific load that the generating facility will serve, differs from the requirement in non-retail choice markets, where the only requirement is to have RERRA verification that the ERAS interconnection request will address a resource adequacy deficiency without identifying specific customers to be served.[328] PIOs explain that, for example, in Illinois, an independent power producer may sell capacity credits to different counterparties each year or sell into the planning resource auction, which supports resource adequacy; however, an independent power producer that intends to participate in these markets will not be able to benefit from ERAS. PIOs add that, in Michigan, there is a 10% cap on the total amount of customer load that may take supply under retail choice, which is currently met and has been for several years. PIOs state that the cap on retail choice load cannot be increased until a new load joins a utility's system, which could make it difficult for an independent power producer to contract with a new large load for retail choice before such load joins the transmission system. PIOs further explain that once a new load joins the transmission system and the cap is increased, interconnection customers already in the queue would have the first opportunity on supplying the load.

130. Clean Energy Associations state that the Commission previously rejected a proposal by Xcel Energy Operating Companies to expedite interconnection requests selected through a state-sponsored procurement process, finding that this would discriminate against customers that "are not part of the state-sponsored bidding process" and would provide transmission owners "the power to discriminate against non-affiliated generation projects."[329]

(b) ERAS Cap and Carve Outs

131. Several protesters argue that MISO's proposed cap and carve outs are arbitrary.[330] PIOs and Invenergy argue that MISO has failed to demonstrate how the proposed limit of

[328] PIOs Protest at 13-14.

[329] Clean Energy Associations Docket No. ER25-1674 Protest at 43-44 (citing *Xcel*, 106 FERC ¶ 61,260 at PP 21, 22).

[330] EPSA Protest at 7-8; Invenergy Protest at 13; PIOs Protest at 18-20; Vistra Protest at 8.

68 ERAS interconnection requests is tailored to ensure just and reasonable rates.[331] Several protesters also argue that MISO's proposed carve outs for independent power producers and retail choice loads are discriminatory.[332]

132. PIOs argue that MISO's proposed carve out of eight ERAS interconnection requests for retail choice load does not reduce discrimination for retail choice load in Illinois and Michigan.[333] PIOs argue that MISO has not demonstrated how eight interconnection requests is an equitable approximation of those customer bases' relative sizes and projected shortfalls. PIOs contend that not requiring RERRA approval in order for ERAS interconnection requests to move forward in retail choice markets may result in ERAS interconnection requests that are not well suited to meet the state's needs.[334] Further, PIOs assert that MISO's proposed 10-day window to allow the RERRA to veto an ERAS interconnection request in retail choice markets is not enough time for such RERRAs to adequately review the proposed interconnection request.

133. PIOs argue that MISO's Revised ERAS Proposal is also unduly discriminatory because it largely excludes independent power producers from the process.[335] PIOs state that while they agree that the proposed carve out of 10 ERAS interconnection requests for independent power producers without an LSE agreement lessens the discriminatory effect of ERAS somewhat, MISO's argument that the carve out provides independent power producers with comparable access to the ERAS process is not true. PIOs state that a truly non-discriminatory process would provide independent power producers with a fair opportunity to compete for 100% of the ERAS cap, rather than 15% of the cap with no support as to how the amount was determined. PIOs further claim that splitting a cap into smaller buckets for different types of interconnection customers does nothing to establish competition that can limit costs to consumers.

134. Invenergy argues that MISO's proposed carve out for independent power producers does not make participation easier for such entities because it does not alleviate the contracting challenges in MISO, which typically require an estimate of project costs

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[331] Invenergy Protest at 13; PIOs Protest at 18.

[332] Clean Energy Associations Protest at 30-31; Clean Grid Alliance Protest at 26; COMPP Protest at 9; Constellation Protest at 6 (citing Transmittal at 25); EPSA Protest at 4-5; Illinois Commission Comments at 4-5; Invenergy Protest at 15-16; PIOs Protest at 5-6; Vistra Protest at 8, 12.

[333] PIOs Protest at 12-13.

[334] *Id.* at 13-14.

[335] *Id.* at 5-6.

before finalizing off-taker agreements.[336] Invenergy adds that MISO's requirement to contract with an LSE will raise consumer prices because contracts will be executed without knowing the full costs of a project, and such costs will be passed on to consumers.

135. Several protesters argue that the Tariff should be clarified to explain that independent power producers are eligible to participate in the initial 50 project tranche if those independent power producers are serving LSEs.[337] EPSA states that the proposed Tariff language, which states that there is a "maximum of" eight interconnection requests for retail choice load and 10 interconnection requests for independent power producers, does not properly reflect MISO's intent to allow independent power producers the opportunity to compete for the other 50 non-carve out slots.[338] Vistra suggests that the words "a maximum of" in GIP section 3.9.2 be struck and the language in GIP section 3.8.2 be clarified to reflect MISO's intent to reserve a minimum number of slots for eligible independent power producer interconnection requests to participate in ERAS, rather than to cap independent power producer project participation.[339] EPSA and COMPP similarly urge the Commission to require MISO to clarify the Tariff language.[340]

136. Clean Energy Associations argue that, in the case where an ERAS interconnection request overlaps with more than one carve out, MISO's proposed Tariff language is unclear as to whether a slot from both carve outs would be eliminated.[341] Similarly, PIOs argue that it is unclear whether an independent power producer in Michigan or Illinois with a supply agreement, not with an LSE, would qualify for the independent power producer or retail choice carve out under MISO's proposal.[342]

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[336] Invenergy Protest at 15-16.

[337] *See, e.g.*, EPSA Protest at 4-5; Illinois Commission Comments at 4-5; Vistra Protest at 8, 12 (citing MISO, Proposed Tariff, attach. X (175.0.0), §§ 3.9.2, 3.8.2).

[338] EPSA Protest at 4 (citing Transmittal at 12); *see also* COMPP Protest at 9; Vistra Protest at 12.

[339] Vistra Protest at 12 (citing to MISO, Proposed Tariff, attach. X (175.0.0), §§ 3.9.2, 3.8.2).

[340] COMPP Protest at 9; EPSA Comments at 4-5.

[341] Clean Energy Associations Protest at 30.

[342] PIOs Protest at 15.

137. Clean Energy Associations also argue that it is unclear regarding whether independent power producers can compete on equitable terms for the remaining 50 spots in ERAS because MISO's proposed Tariff language is not clear on the types of agreements it will accept for the 50 slots.[343] Clean Energy Associations explains that the "other agreement" category for the executed agreement requirement suggests that independent power producers may have agreements with entities other than LSEs and asserts that MISO should clarify that such ERAS interconnection requests are not precluded from competing for the 50 slots.[344] Additionally, Illinois Commission states that MISO's proposed language in GIP section 3.9.2 is unclear as to whether "agreements with entities other than Load Serving Entities" is intended to mean large load end users such as data centers.[345]

(c) Other ERAS Eligibility Requirements

138. Several protesters argue that the Revised ERAS Proposal lacks stringent and objective eligibility criteria and differentiate the ERAS eligibility requirements from RTO/ISO generator interconnection proposals that the Commission has accepted.[346] For example, MISO IPPs argue that the CAISO IPE proposal's scoring criteria appropriately incorporated state and local regulatory authorities' interests, whereas ERAS fully delegates ERAS eligibility to RERRAs.[347] Similarly, MISO IPPs and Clean Energy Associations argue that the Commission found the PJM RRI proposal's specific scoring

[343] Clean Energy Associations Protest at 30.

[344] *Id.* at 31.

[345] Illinois Commission Comments at 5.

[346] Clean Energy Associations Docket No. ER25-1674 Protest at 43; Clean Grid Alliance Protest at 11,15; MISO IPPs Docket No. ER25-1674 Protest at 19-21 (citing CAISO IPE Order, 188 FERC ¶ 61,225 at P 94); NextEra Docket No. ER25-1674 Protest at 24 (citing MISO, Tariff, attach. X (GIP) (171.0.0), §§ 3.6, 7.9.3).

[347] MISO IPPs Docket No. ER25-167 Protest at 20 (citing CAISO IPE Order, 188 FERC ¶ 61,225 at P 123).

criteria in the tariff to be facially neutral,[348] while ERAS criteria are not facially neutral because RERRAs determine eligibility.[349]

139. Additionally, Clean Grid Alliance and NextEra contend that the ERAS financial requirements are not sufficiently stringent, conflict with MISO's recent queue reforms, and do not disincentivize speculative interconnection requests from joining ERAS.[350] NextEra argues that an interconnection customer could submit a speculative interconnection request into ERAS to determine its liability for network upgrades, withdraw after seeing the results, and receive a refund of all the fees paid minus the $100,000 D1 application fee and study costs. NextEra states that the prospect of losing $100,000 is unlikely to act as a material deterrent to the submission of speculative interconnection requests or a reliable indicator of the commercial viability of a project.[351] Clean Grid Alliance argues that the M2 payment in ERAS should be forfeited if the interconnection customer withdraws to deter speculative interconnection requests and minimize late stage restudies.[352]

140. Clean Energy Associations argue that the $100,000 D1 application fee discriminates against independent power producers.[353] Clean Energy Associations assert that, while LSEs can afford high up-front costs that they can pass along to ratepayers, independent power producers do not have this same ability, particularly in the early stages of development before they have secured financing. Clean Energy Associations argue that ERAS incents LSEs to submit interconnection requests to ERAS regardless of readiness because their ratepayers will likely bear the risk responsibility for delays, cost overruns, or stranded assets.

141. Clean Grid Alliance contends that MISO's lack of requirement for a financial security for affected system upgrades and other studies not completed by the execution of

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[348] Clean Energy Associations Docket No. ER25-1674 Protest at 43; MISO IPPs Docket No. ER25-1674 Protest at 20 (citing PJM RRI Order, 190 FERC ¶ 61,084 at P 123).

[349] Clean Energy Associations Docket No. ER25-1674 Protest at 43; MISO IPPs Docket No. ER25-1674 Protest at 20.

[350] Clean Grid Alliance Protest at 11-12, 15; NextEra Docket No. ER25-1674 Protest at 25-26.

[351] NextEra Docket No. ER25-1674 Protest at 26.

[352] Clean Grid Alliance Protest at 80-81.

[353] Clean Energy Associations Docket No. ER25-1674 Protest at 19.

an EGIA is not stringent enough and may lead to late-stage withdrawals.[354] Clean Grid Alliance further contends that the Revised ERAS Proposal's lack of provisions to address potential ERAS restudies, based on an expectation that there will not be any, is a "gamble."[355]

142. Constellation argues that that the proposal appears to impose higher and unreasonable disclosure obligations on projects serving retail choice customers.[356] DTE Electric states that the Commission should clarify that the sunset provision in MISO's proposed Tariff language does not preclude it from revisiting the sunset date if circumstances require.[357]

143. NextEra asserts that the ERAS site control requirements are not more rigorous than those applied to DPP interconnection requests,[358] and even if they were, demonstrating 100% site control is insufficient to ensure that ERAS interconnection requests are "shovel ready," as other resources that demonstrate 100% site control still encounter challenges that delay commercial operation.[359] NextEra asserts that MISO did not propose objective criteria to ensure that interconnection requests are "shovel ready," and therefore there is no assurance that ERAS interconnection requests will not be delayed similarly to DPP interconnection requests.[360]

144. PIOs argue that MISO's proposed commercial operation date requirement fails to prevent preferential treatment towards ERAS interconnection requests, which may not

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[354] Clean Grid Alliance Protest at 13.

[355] *Id.* at 13-14.

[356] Constellation Protest at 5-6.

[357] DTE Electric Comments at 5.

[358] NextEra Docket No. ER25-1674 Protest at 24-25 (citing MISO, Proposed Tariff, attach. X(GIP) (175.0.0), § 7.2.2.1(ii) (requiring customers to demonstrate 100% site control for all "Interconnection Customer's Facilities (including demonstration of switchyard site control if requested by the Transmission Provider), and, if applicable (i.e., when the Interconnection Customer is providing the site for such facilities), the Transmission Owner's Interconnection Facilities and Network Upgrades at the [Point of Interconnection] that the Interconnection Customer will develop")).

[359] NextEra Docket No. ER25-1674 Protest at 25 (citing Witmeier Rebuttal Testimony at 14).

[360] NextEra Protest at 25.

reach commercial operation for another eight years following MISO's filing.[361] PIOs also point out that MISO's commercial operation date requirements differ from those in PJM RRI, which required RRI projects to waive the one-year milestone extension provided for in PJM's generator interconnection process.[362]

(1) Executed Agreement Requirement

145. Several protesters argue that the executed agreement requirement unduly discriminates against different classes of interconnection customers. As evidence, they point out that pursuant to this executed agreement requirement, non-LSEs and other competitive generation developers must obtain an offtake agreement to qualify, while LSEs can simply voice an intention to self-supply.[363] Michigan Commission states that while the carve out for 10 independent power producer interconnection requests is helpful, incumbent utilities can self-supply while independent power producers must take an additional step of having an executed agreement or work with an LSE to meet a resource adequacy need.[364] Several protesters similarly assert that the requirement for independent power producers contracting with LSEs to submit an executed agreement to achieve the first stage of eligibility fails to provide access to independent power producers on a comparable and sufficiently non-discriminatory basis.[365] Several protesters assert that this is an additional, unfair burden that limits competitive independent power producers' viability in ERAS.[366] EPSA requests that the Commission require MISO to remove these requirements for independent power producers or, at a minimum, that the Commission delay the due date for ERAS submission for the independent power producer carve outs, which would allow time for MISO states to

[361] PIOs Protest at 25.

[362] *Id.* at 26 (citing PJM RRI Order, 190 FERC ¶ 61,084 at P 265).

[363] Clean Energy Associations Protest at 31; Clean Energy Associations Docket No. ER25-1674 Protest at 11-17; Clean Grid Alliance Protest at 26-27, 75; MISO IPPs Docket No. ER25-2674 Protest at 12-13; NextEra Docket No. ER25-1674 Protest at 36-38; PIOs Protest at 5; PIOs Docket No. ER25-1674 Protest at 10-12.

[364] Michigan Commission Protest at 10.

[365] Clean Energy Associations Docket No. ER25-1674 Protest at 11-17; EPSA Comments at 5; Invenergy Protest at 7; Michigan Commission Protest at 10; MISO IPPs Docket No. ER25-1674 Protest at 12-13; NextEra Docket No. ER25-1674 Protest at 37-38; PIOs Protest at 5; PIOs Docket No. ER25-1674 Protest at 11.

[366] Clean Energy Associations Docket No. ER25-1674 Protest at 11-17; Clean Grid Alliance Protest at 61-62.

determine the RERRA verification process for independent power producer interconnection requests, and for all independent power producers to negotiate the required agreements and meaningfully participate in the ERAS process.[367] Invenergy argues that it is unclear how independent power producers may present contracts to RERRAs under MISO's proposal, particularly where some state laws prohibit interconnection customers from making requests to RERRAs.[368]

146. MISO IPPs, Clean Energy Associations, Clean Grid Alliance, PIOs, and NextEra assert that independent power producers and load typically execute agreements after receiving cost estimates to appropriately price the agreement before execution.[369] Accordingly, these entities argue that the Revised ERAS Proposal discriminates against non-LSEs because ERAS is either non-viable for non-LSEs or is more stringent than the self-supply acknowledgement.[370] Clean Energy Associations assert that because some network upgrade costs will not be known in time to execute a durable offtake agreement, this may harm reliability needs and could cause disruption without benefit, as purchasers would sign a PPA that may lead to over-procurement to avoid contract termination or dropping out of ERAS altogether.[371]

147. NextEra and PIOs contend that independent power producers may not be able to enter ERAS unless an LSE grants the independent power producer an agreement or otherwise cooperates with the independent power producer, which, in effect, allows LSEs to choose which resources qualify for ERAS.[372] NextEra asserts that the CAISO IPE proposal gave independent power producers realistic opportunities to obtain interconnection service, but that ERAS does not have any of the CAISO IPE proposal's

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[367] EPSA Comments at 5-6.

[368] Invenergy Protest at 5.

[369] Clean Energy Associations Docket No. ER25-1674 Protest at 12, 49; Clean Grid Alliance Protest at 74-75; MISO IPPs Docket No. ER25-1674 Protest at 13; NextEra Docket No. ER25-1674 Protest at 36-37; PIOs Docket No. ER25-1674 Protest at 11-12.

[370] Clean Energy Associations Protest at 13-16; Clean Grid Alliance Protest at 61-62; MISO IPPs Docket No. ER25-1674 Protest at 13; NextEra Docket No. ER25-1674 Protest at 36-37.

[371] Clean Energy Associations Docket No. ER25-1674 Protest at 13-15.

[372] NextEra Docket No. ER25-1674 Protest at 38; PIOs Docket No. ER25-1674 Protest at 10.

guardrails to ensure no undue discrimination against independent power producers.[373] Additionally, NextEra asserts that the risk of undue discrimination is exacerbated by ERAS allowing some entities, like cooperatives, to be both LSEs and RERRAs, which may incentivize the entity to prevent independent power producers from obtaining access to ERAS to protect the competitive advantage of its resources.[374] NextEra asserts that the Commission has historically rejected proposals that disadvantage independent power producers and other non-incumbents, citing to a PacifiCorp proposal that had different commercial readiness demonstration options for LSEs and independent power producers[375] and a Public Service Company of Colorado proposal that had commercial readiness criteria that were "likely too stringent for independent power producers to meet."[376] NextEra further asserts that, in Order No. 2023, the Commission declined to adopt requirements and criteria for demonstrating commercial readiness by submitting an executed term sheet or an executed PPA because these "may not be workable in markets where merchant sales are common."[377]

148. Clean Grid Alliance argues that independent power producers do not have access to information about load that "meet[s] an identified resource adequacy and/or reliability need," either at all or at the same time/level as LSEs.[378] Clean Grid Alliance also argues that the ERAS proposal will send the wrong market signals and stifle competition because it denies independent power producers' meaningful participation and restricts competition.[379]

149. Clean Grid Alliance further argues that ERAS unduly preferences LSEs because an LSE can submit an expedited process review as an exception to the standard MISO Transmission Expansion Plan (MTEP) process to include transmission to serve such spot load, which may make obtaining a RERRA certification easier, while an independent

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[373] NextEra Docket No. ER25-1674 Protest at 39 (citing CAISO IPE Order, 188 FERC ¶ 61,225 at PP 174, 176).

[374] *Id.* at 38.

[375] *Id.* at 34 (citing *PacifiCorp*, 171 FERC ¶ 61,112, at PP 68-69 (2020)).

[376] *Id.* at 35 (citing *Pub. Serv. Co. of Colo.*, 183 FERC ¶ 61,166, at P 65 (2023) (*PSCo*)).

[377] *Id.* at 35-36 (citing Order No. 2023, 184 FERC ¶ 61,054 at PP 614-615, 696-98).

[378] Clean Grid Alliance Protest at 73.

[379] *Id.* at 61-62.

power producer cannot.[380] Additionally, Clean Grid Alliance contends that independent power producers will face greater barriers to exit the DPP due to the withdrawal penalties than LSEs, which have a safety net with costs backstopped through the state public utility commission.[381] Accordingly, protesters assert that the executed agreement requirement in ERAS is an additional, unfair burden that limits competitive independent power producers' viability.

(2) Local Resource Zone

150. PIOs argue that MISO's proposed requirement that an ERAS interconnection request must be located within the same Local Resource Zone as the load it will serve, unless the project was included in a resource filing or other submission to the RERRA, adds another element of discrimination.[382] Invenergy argues that the proposed Local Resource Zone requirement artificially constrains the number of eligible interconnection requests that might be suited to serve a resource adequacy need.[383]

151. PIOs further argue that the structural differences in relationship with the RERRA for independent power producers compared to LSEs will make it significantly harder for independent power producers to ensure that a project located outside of a Local Resource Zone is included in a resource filing or submission before the RERRA.[384] Relatedly, Constellation argues that it is "beyond dispute" that a generating facility in one Local Resource Zone can serve load in another, and it is therefore unduly discriminatory for MISO to propose excluding an interconnection request for consideration in ERAS simply because the proposed generating facility is located in a different Local Resource Zone.[385] Constellation asserts that MISO's proposed exception in this respect does not change that. Further, Constellation argues that MISO has not explained what "resource filing or other submission made to the RERRA" would satisfy this requirement, particularly in retail choice states.

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[380] *Id.* at 73-74.

[381] *Id.* at 79.

[382] PIOs Protest at 9.

[383] Invenergy Protest at 12.

[384] PIOs Protest at 9.

[385] Constellation Protest at 7.

(3) Requested Interconnection Service May Not Exceed 150% of Identified Need

152. Michigan Commission and PIOs argue that, by capping interconnection requests at 150% of the identified need, the Revised ERAS Proposal effectively excludes renewable energy project participation and unfairly tilts the scales in favor of thermal generation.[386] PIOs explain that any new generation resource seeking interconnection needs interconnection service that matches its nameplate capacity, or it will be forced to curtail its output regularly.[387] PIOs argue that, as a result, ERAS effectively eliminates any resource receiving less than 67% capacity accreditation because such resources would have to request interconnection service in excess of 150% of the identified MW need to match the nameplate capacity.[388] PIOs further argue that MISO fails to engage with the fact that wind and solar resources receive significantly lower accreditation than other generation facility types and will therefore be uniquely impacted.[389] PIOs add that data presented at recent stakeholder meetings demonstrate that accredited values for renewable generation fell below 67%.[390] PIOs assert that MISO's discriminatory approach in the ERAS process cannot be justified because it is not tailored to meet MISO's stated resource adequacy and reliability needs.

153. Michigan Commission contends that the Initial ERAS Proposal, which capped interconnection requests at 125% of identified need and based the requirement on accredited capacity, instead of interconnection service, had a closer link to resource adequacy needs and was more equitable across fuel types. Michigan Commission asserts that in the alternative, if the amount remains based on interconnection service, the cap

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[386] Michigan Commission Protest at 14-15; PIOs Protest at 10-11.

[387] PIOs Protest at 10.

[388] *Id*. PIOs further explain that, for example, "To meet a resource adequacy need of 100 MW, a resource with, e.g., 50% capacity accreditation would need to build to 200 MW of nameplate capacity, but Interconnection Service at that level would exceed MISO's proposed 150% limit." *Id*.

[389] *Id.* at 11.

[390] *Id.* (citing MISO, Resource Adequacy Subcommittee (RASC), *LOLE Modeling Enhancements Storage Modeling* 19 (Apr. 9, 2025), https://cdn.misoenergy.org/20250409%20RASC%20Item%2008%20LOLE%20Modeling%20Enhancements%20St orage%20Modeling689245.pdf (using "even loss" values pursuant to MISO's proposed modeling approach in that presentation)).

should be raised to 200% to allow for renewable projects to participate and assuage discriminatory concerns.[391]

154. Clean Energy Associations also argue that the new requirement that the amount of interconnection service requested must not exceed 150% of the identified MW need will functionally cap intermittent resources and does not better link the claimed resource adequacy need and the proposed interconnection request, contrary to MISO's claim.[392]

iii. Answers

(a) MISO Answer

155. MISO states that it started with a base of 50 interconnection requests similar to the PJM RRI but ultimately proposed additional carve outs for 10 independent power producer interconnection requests and eight retail choice interconnection requests to reflect its unique environment that includes two retail choice states.[393] MISO argues that this cap, along with the 10 interconnection request limit per ERAS quarterly study period, will enable MISO to work efficiently on both ERAS and DPP studies. MISO explains that it determined a cap of eight interconnection requests for retail choice states based on internal analysis and discussion with retail choice states.[394] MISO asserts that a cap of eight interconnection requests for retail choice states strikes the right balance to proportionately allocate interconnection requests to retail choice states, based on the portion of MISO's footprint that those states represent.[395] MISO clarifies that the two carve outs are separate.

156. In response to protests that the 10-day RERRA review period is insufficient, MISO states that the 10-day timeframe, which was originally agreed to by stakeholders, is not intended to be a comprehensive review of the interconnection requests.[396]

157. MISO further clarifies, in response to Constellation, that the Revised ERAS Proposal does not impose higher obligations on interconnection requests serving retail

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[391] Michigan Commission Protest at 15.

[392] Clean Energy Associations Docket No. ER25-1674 Protest at 10.

[393] MISO Answer at 13-14.

[394] *Id.* at 15.

[395] *Id.* (citing Witmeier Testimony at 37).

[396] *Id.* at 16.

choice customers.[397] MISO states that it is requiring the same non-confidential information from all ERAS interconnection requests and has created a process to allow interconnection customers serving retail choice customers to participate in ERAS. MISO further states that while it recognizes that retail load in Michigan is already fully provided for, it cannot require the states to serve resource adequacy needs in certain ways and is simply providing a tool for states with resource adequacy needs.[398]

158. MISO asserts that the purpose of the independent power producer carve out is to address claims that LSEs could block independent power producers from participating in the ERAS process.[399] MISO clarifies that independent power producers may also submit interconnection requests in the remaining group of 50 ERAS interconnection requests so that the independent power producer carve out functions as a guaranteed floor of 10 independent power producer-only interconnection requests. MISO answers that it opposes a delay in the due date for ERAS submission for the independent power producer carve out because it is impractical and administratively burdensome.[400]

159. MISO asserts that a ranking or scoring process is not appropriate because MISO does not believe that it should prescribe to a state or RERRA which interconnection requests should be selected.[401] MISO states that a state or RERRA can implement their own scoring or ranking criteria, but it is ultimately the state's role, not MISO's, to determine the resources that will be utilized in their jurisdiction due to the unique jurisdictional divide under the FPA. Thus, MISO states that it will not specify a state process, regardless of protesters' arguments that doing so would be more transparent or otherwise preferable.

160. MISO contends that the new RERRA verification requirement provides states and RERRAs with different regulatory review processes necessary flexibility and does not supplant these review processes.[402] MISO states that an interconnection request approved to participate in ERAS must still receive approval through the state's corresponding regulatory review process, thus ensuring that the RERRA verification does not pre-determine any outcome of an applicable state process. MISO further asserts that it cannot

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[397] *Id.* at 17.

[398] *Id.* at 18.

[399] *Id.* at 19.

[400] *Id.* at 20.

[401] *Id.* at 24-25.

[402] *Id.* (citing Transmittal at 31; MISO Proposed Tariff, attach. X (GIP), § 3.9.1).

and should not mandate a set review process with pre-determined characteristics that supplant the RERRA's determinations with its own. MISO believes that RERRAs are the appropriate entity to select ERAS participants, especially with the Revised ERAS Proposal's guardrails. MISO disagrees with protesters that RERRAs will be incentivized to provide a verification for certain interconnection requests because the interconnection requests would need to receive approval through a full state review process. Finally, MISO states that the Revised ERAS Proposal balances respect for states' jurisdictions over their own resource mixes with requiring sufficient information and verification from the RERRA that the proposed interconnection requests is appropriate for ERAS.[403]

161. In response to Michigan Commission's opposition to a RERRA verification relying on a state energy forecast or other forward-looking forecast as support, and its contention that this is too broad as to allow nearly any interconnection request to qualify, MISO argues that it believes that it is a RERRA's prerogative to determine what supporting information to utilize.[404] MISO further argues that it believes that it is not appropriate for one state to dictate the supporting information that another state uses. MISO further explains that it is not the resource planner for the states within its footprint, and the RERRA verification requirement will tighten the nexus between the proposed ERAS interconnection request and an identified resource adequacy and/or reliability need. MISO additionally contends that the Local Resource Zone requirement will tighten the nexus between the RERRA-verified interconnection request and the resource adequacy need.[405] MISO asserts that the RERRA verification and executed agreement requirements provide strong evidence that an interconnection request's output will be used by the designated load.

162. In response to protesters' arguments regarding *Xcel*, MISO states that the Commission determined that the process in that case was unduly discriminatory because it excluded interconnection customers that did not participate in the state-sponsored bidding process.[406] MISO contends that this is not the case with the ERAS process because it is open to all applicants, not just those involved in a state solicitation process.

163. MISO states that the arguments that LSEs will exert undue influence over which resources qualify for ERAS by refusing to enter into agreements with competing

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[403] *Id.* at 25-26.

[404] *Id.* at 24.

[405] *Id.* at 26-27 (citing Tab A, (Witmeier Docket No. ER25-1674 Rebuttal Testimony, at 10).

[406] MISO Docket No. ER25-1674 Answer at 16-17 (citing *Xcel*, 106 FERC ¶ 61,260 at P 22).

interconnection customers assumes counterintuitive behavior from LSEs and load drivers that should reasonably select the most preferable project option.[407] MISO argues that ERAS does not require nor encourage the selection of an LSE's project over another equally beneficial project, and regardless, the executed agreement requirement will severely limit the possibility of this occurring. MISO also contends that while LSEs that own generation may self-supply, they still must receive approval from the RERRA.[408] Additionally, MISO states that any disadvantage experienced by independent power producers in this competition is not a result of ERAS.[409] MISO also notes that ERAS is not intended to work for the majority of interconnection requests but to be a unique, time-limited process for "shovel ready" projects to address near-term load needs.[410]

164. MISO argues that, contrary to protester assertions, the ERAS process is intended to be complementary to the state regulatory review process that ensures that projects are necessary, cost-effective, and in the public interest.[411] MISO further clarifies that while an interconnection request must include a RERRA verification to participate in ERAS, that does not guarantee acceptance into ERAS, and the other eligibility requirements will ensure that an interconnection request is "shovel ready."[412]

165. MISO states that while it considered a scoring approach, it ultimately determined that because of MISO's composition, states should be left to determine their own resource adequacy needs.[413] MISO additionally states that ERAS does not need scoring criteria because its strict eligibility requirements ensure that only projects that are truly commercially ready can participate.[414]

166. In response to concerns that the executed agreement requirement is unduly discriminatory toward independent power producers, MISO states that ERAS is structured to encourage negotiation and agreement to occur earlier in the planning

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[407] *Id.* at 25.

[408] *Id.* at 28.

[409] *Id.* at 25.

[410] *Id.* at 27.

[411] *Id.* at 18.

[412] *Id.* at 19.

[413] *Id.* at 31.

[414] *Id.* at 32.

process. MISO states that it has found that DPP interconnection customers without PPAs cited the lack of a PPA as the reason for their commercial operation date delay. MISO also states that it permits flexibility by not requiring detail in these agreements beyond that they will meet the load's identified resource adequacy need.[415]

167. MISO clarifies that it limited ERAS interconnection requests to 150% of the identified need based on the MW of interconnection service requested, not based on nameplate or accredited capacity.[416] MISO asserts that ERAS is focused on interconnection service rather than accredited capacity because it is resource neutral and only focused on "shovel ready" projects.[417]

168. In addition, MISO provides several clarifications regarding the purpose and use of proposed ERAS fees, milestones, and payments. MISO explains that, if an ERAS application is deemed ineligible, the non-refundable D1 application fee will be used for costs related to managing the ERAS process and that the application fee also serves to ensure only "shovel ready" projects are submitted.[418] MISO also clarifies that, with regard to proposed GIP provisions specifying that ERAS interconnection customers are eligible for a refund of the "remaining" M2 milestone upon withdrawal after GIA execution, the remaining M2 milestone would be what remains after meeting the initial milestone payment and/or the network upgrade costs memorialized in the EGIA.[419] MISO explains that any refund of the M2 milestone after GIA execution assumes that either the interconnection request did not result in network upgrades or that those network upgrades were less than the M2 milestone. In addition, MISO explains that an ERAS interconnection customer is liable for the network upgrade costs regardless of whether those costs are covered by the initial payment requirement under the EGIA or financial security rules. MISO reiterates that ERAS interconnection customers are responsible for any remaining network upgrade costs documented in the EGIA, and any corresponding facilities construction agreements or multi-party facilities construction agreements, even if the ERAS interconnection customer withdraws after EGIA execution.[420] Finally, MISO explains that, regarding whether transfer of ownership of

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[415] *Id.* at 28-29.

[416] MISO Answer at 28.

[417] *Id.* at 28-29.

[418] *Id.* at Tab B, MISO Supplemental Answer, Docket No. ER25-1674-000 (filed Apr. 29, 2025), at 3 (MISO Docket No. ER25-1674 Supplemental Answer).

[419] MISO Docket No. ER25-1674 Supplemental Answer at 6.

[420] *Id.* at 7 (citing MISO, Proposed Tariff, attach. X (GIP) (169.0.0), § 3.9.6.3).

ERAS projects after EGIA execution also transfers the load obligation, the commercial terms to address project transfer are outside the scope of the ERAS process.

(b) Additional Answers

169. In response to MISO's answer, Clean Grid Alliance argues that the ERAS process, unlike the DPP, is not an open or non-discriminatory process.[421] Instead, Clean Grid Alliance argues that the ERAS process makes LSEs, which "have an incentive to favor their own generation a gatekeeper for new generation."[422] Clean Grid Alliance further contends that FPA section 205 requires MISO to affirmatively demonstrate that its proposal is not unduly discriminatory and will not result in the unintended consequences discussed by protesters.[423] Clean Grid Alliance asserts that attempts to distinguish *Xcel* are unconvincing because the unduly discriminatory outcome that the Commission rejected there, where "Interconnection Customers that [did] not take part in . . . state-sponsored bidding [could not] compete . . . on an equal footing"[424] is "akin to" that presented by the ERAS proposal.[425] More specifically, Clean Grid Alliance claims that the executed agreement requirement, which requires "*some* kind of agreement in place with an LSE," prevents independent power producers from competing with LSEs on equal footing.[426] Clean Energy Alliance further avers that Order No. 2003 makes clear that the Commission should not approve deviations from its *pro forma* LGIP that provide "the mere opportunity for LSE (transmission owner) preference" and that the opportunity for undue discrimination is intrinsic to the ERAS proposal.[427]

170. Further, Clean Grid Alliance argues that MISO fails to support its claim that it worked closely with states to ensure that independent power producers have comparable

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[421] Clean Grid Alliance Docket No. ER25-1674 Answer at 3-4.

[422] *Id.*

[423] *Id.* at 4 (citing *Midcontinent Indep. Sys. Operator, Inc.*, 154 FERC ¶ 61,247, at P 77 (2016)).

[424] *Id.* at 5 (citing *Xcel*, 106 FERC ¶ 61,260 at P 23).

[425] Clean Grid Alliance Docket No. ER25-1674 Answer at 5.

[426] *Id.* at 5-6 (quoting MISO Docket No. ER25-1674 Answer at 25 (emphasis in original)).

[427] *Id.* at 6 (citing Order No. 2003, 104 FERC ¶ 61,103 at P 696).

ability to participate in the ERAS process.[428] Additionally, Clean Grid Alliance asserts that it has cited "ample" precedent to support a finding that LSEs have an incentive to favor their own generation.[429] Clean Grid Alliance claims that the ERAS proposal is unduly discriminatory by providing an "exclusive preferential fast track for priority access to transmission headroom over DPP project to RERRA-anointed projects."[430] To this point, Clean Grid Alliance contends that ERAS interconnection requests enjoy penalty-free withdrawal during the study process, an advantage over DPP interconnection requests, and that relaxing DPP rules conflicts with MISO's claim that ERAS interconnection requests are "shovel ready." Further, Clean Grid Alliance argues that there is undue preference with respect to the ERAS power flow study dispatch over the DPP power flow study dispatch that "significantly lowers" the cost of interconnection for ERAS interconnection requests.[431]

171. Clean Grid Alliance asserts that MISO has not justified the proposed cap of 68 interconnection requests to be studied in ERAS. Specifically, Clean Grid Alliance avers that MISO's statement that it chose to cap LSE ERAS interconnection requests at 50, because that was the cap for the PJM RRI, is unreasonable because MISO has different resource needs than PJM and, further, that ERAS does not resemble the PJM RRI construct.[432]

172. Additionally, Clean Grid Alliance asserts that MISO does not justify allocating only 10 interconnection requests to independent power producers when LSEs have nearly unfettered access to the bulk of the ERAS interconnection request slots, to which LSEs can impose barriers to independent power producers' access.[433] Clean Grid Alliance asserts that RERRAs will not be able to verify ERAS interconnection requests submitted by independent power producers over those submitted by LSEs because LSEs will be able to deny agreements to independent power producers and reserve the 50 ERAS interconnection request slots for their own ERAS interconnection requests. Clean Grid Alliance avers that this is unduly discriminatory and preferential because independent

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[428] *Id.* at 7.

[429] *Id.* at 8 (citing *Nat. Ass'n of Reg. Util. Comm'rs v. FERC*, 475 F.3d 1277, 1279 (D.C. Cir. 2007); *Xcel Energy Servs., Inc. v. FERC*, 41 F.4th 548, at 561 (D.C. Cir. 2022)).

[430] *Id.* at 8-9.

[431] *Id.* at 9-10.

[432] Clean Grid Alliance First Answer at 10.

[433] *Id*. at 13-14.

power producers and LSEs are similarly situated because both entities seek to develop generation to serve load. Clean Grid Alliance adds that an LSEs' obligation to serve does not justify the undue discrimination created by the Revised ERAS Proposal.[434]

173. Clean Grid Alliance argues that, due to the reliability gaps resulting from MISO's proposed study modeling approach, the Revised ERAS Proposal conflicts with open access principles.[435]

174. MISO IPPs argue that the Commission cannot assume that there will be no undue discrimination or preference, or rely on RERRAs to see to that outcome, when MISO's Tariff language does not provide a reasoned basis for concluding that MISO has guarded against undue discrimination or preference.[436] MISO IPPs state that MISO's answer incorrectly defends that undue discrimination or preference as either a necessary feature or a harmless byproduct of its regulatory model.[437] More specifically, MISO IPPs argue that this proceeding is about interconnection service, which is within the Commission's exclusive jurisdiction under the FPA, and that the Commission is obligated to prevent undue discrimination or preference within its jurisdiction regardless of the MISO state's role in maintaining resource adequacy.[438] MISO IPPs also state that MISO's valid resource adequacy needs are a non-sequitur that does not excuse a violation of the statutory prohibition on treating similarly situated entities differently.[439] MISO IPPs aver that MISO's suggestion that RERRAs would not engage in discriminatory or preferential behavior because each ERAS project will still require state permits is not enough to meet MISO's burden under FPA section 205.[440]

175. MISO IPPs also state that the proposed carve out for 10 ERAS interconnection requests that may be submitted by independent power producers is unjustified and unduly discriminatory. MISO IPPs argue that MISO's answer, which states that independent power producers can also compete with the general group of 50 ERAS interconnection requests, does not resolve the undue discrimination concerns with the Revised ERAS

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[434] Clean Grid Alliance Docket No. ER25-1674 Answer at 14.

[435] Clean Grid Alliance First Answer at 8.

[436] MISO IPPs Answer at 4.

[437] *Id.* at 5.

[438] *Id.* at 5-7.

[439] *Id.* at 7-8.

[440] *Id.* at 8 (citing MISO Answer at 25).

Proposal's cap and carve outs because the 50 slots allotted for LSEs will be controlled by vertically integrated utilities.[441] MISO IPPs argue that MISO has not justified why LSEs should have five times as many slots to submit ERAS interconnection requests.[442]

176. MISO IPPs argue that the Local Resource Zone requirement is unduly discriminatory. Specifically, MISO IPPs argue that the proposed requirement that an ERAS interconnection request only be included in an integrated resource plan filing, instead of approved by a RERRA, is not relevant to the determination of whether the interconnection request is better situated than others to meet the resource adequacy or reliably need in question.[443] MISO IPPs aver that this requirement is susceptible to gaming by LSEs that can adjust their integrated resource plan filings.[444] MISO IPPs further argue that MISO's answer does not explain how the Local Resource Zone requirement will address import-export concerns simply because the interconnection request is proposed in an integrated resource plan.[445]

177. Clean Energy Associations assert that the extent to which MISO will permit independent power producers to compete on equitable terms for the remaining 50 ERAS interconnection request spots remains unresolved by MISO's answer.[446] Clean Energy Associations state that MISO clarifies that, although independent power producers can compete for the 50 ERAS interconnection request spots, "projects submitted by [independent power producers] without LSEs are maxed out at 10 projects."[447] Clean Energy Associations assert that MISO's interpretation does not align with the plain language of the Tariff because the proposed Tariff language does not state that an entity must be an LSE to be eligible to compete for the 50 ERAS interconnection request spots.[448]

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[441] *Id.* at 9-10 (citing MISO Answer at 19).

[442] *Id.* at 10.

[443] *Id.* at 12.

[444] *Id.*

[445] *Id.* (citing MISO Answer at 27).

[446] Clean Energy Associations Answer at 5-6 (citing Clean Energy Associations Protest at 30).

[447] *Id.* at 6 (citing MISO Answer at 19).

[448] *Id.* at 6-7 (citing MISO, Proposed Tariff, attach. X (175.0.0), § 3.9.1(2)(b)).

178. Clean Energy Associations argue that the 10 ERAS interconnection request carve out for independent power producers without an LSE contract is a permission structure for discrimination that contradicts well-established open access principles.[449] Clean Energy Associations assert that, under MISO's interpretation of the Tariff language, independent power producer interconnection requests will be at a disadvantage relative to LSE-owned or affiliated interconnection requests because the requirement to have a contract with an LSE puts the LSE in a gatekeeper role.[450] Furthermore, Clean Energy Associations argue that, by requiring that ERAS generating facilities must serve new load not accounted for in a resource plan or address a resource adequacy deficiency, independent power producers will be at an additional disadvantage because only the RERRA and LSE are likely to know what new load is unaccounted for in a resource plan.[451] Clean Energy Associations assert that the disadvantage faced by independent power producer interconnection requests relative to LSE-owned or affiliated interconnection requests results in a failure by MISO to address the preferential treatment for LSE projects and undue discrimination against independent power producer projects without LSE involvement.[452]

179. Clean Energy Associations contend that MISO's answer did not sufficiently respond to their claim that the 150% nameplate cap would only allow thermal resources to participate in ERAS; rather, MISO merely stated that its approach is resource neutral.[453] Clean Energy Associations assert that MISO ignores that the eligibility of planning resources to provide resource adequacy benefits depend on interconnection service in addition to capacity accreditation. Accordingly, Clean Energy Associations assert that, while remaining facially neutral as to which resources request it, the 150% limitation will operate as a functional bar on certain resources meeting an identified need. Clean Energy Associations argues that this approach will likely prevent non-thermal resources from being considered to meet identified needs because RERRAs and project sponsors are unlikely to consider solutions that would leave a substantial amount of capacity unstudied and incapable of being delivered.[454]

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[449] *Id.* at 8.

[450] *Id.* at 7 (citing Clean Energy Associations Protest at 27-30).

[451] *Id.* (citing Clean Energy Associations Protest at 14).

[452] Clean Energy Associations Answer at 7.

[453] *Id.* at 10 (citing MISO Answer at 29).

[454] *Id.* at 11.

180. PIOs argue that MISO's proposal requiring an ERAS interconnection customer to request interconnection service of no more than 150% of the identified need discriminates against renewable generating resources because it would require such resources to interconnect at a level that prevents them from full economic dispatch. PIOs further argue that this is true even if a renewable generator is paired with battery storage, which PIOs allege would become a prerequisite for renewable generators' participation in ERAS in practice. PIOs contend that this requirement would result in renewable generators being limited in their ability to fully participate in times of increased demand and could impact utilities' future resource planning if renewable generators are limited in their output.[455]

181. PIOs argue that MISO's answer does not address PIOs' concern regarding the adequacy of oversight for the RERRA verification requirement.[456] PIOs contend that MISO did not make meaningful changes to the RERRA role in the Revised ERAS Proposal compared to the Initial ERAS Proposal.[457] PIOs further contend that, in its answer, MISO continues to refuse the adoption of any standard for the RERRA verification to explain how it weighs the merits of similarly situated interconnection requests for participation in ERAS, despite concerns raised by protesters and in Commissioner See's concurrence.[458] PIOs argue that the Revised ERAS Proposal may create reliance on a state or other forward-looking energy forecast as a supporting factor.[459] PIOs further argue that, as the Michigan Commission notes, this aspect of MISO's proposal would allow any interconnection request to be eligible for ERAS as long as a forecast supports it. PIOs contend that, as a result, utility-funded analyses could be utilized to support such forecasts with no quality standards in place. PIOs assert that MISO's inclusion of "other forward-looking forecast" in its Tariff obliges MISO to accept a RERRA verification based on such a forecast.[460]

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[455] PIOs Answer at 7.

[456] *Id.* at 9.

[457] *Id.* at 10.

[458] *Id.* at 10-11 (citing MISO, Proposed Tariff, attach. X (GIP) (175.0.0), § 3.9.1).

[459] *Id.* at 12.

[460] *Id.* (citing 18 C.F.R. § 35.1(e) (2024) ("No public utility shall, directly or indirectly, demand, charge, collect or receive any rate, charge or compensation for or in connection with electric service subject to the jurisdiction of the Commission, or impose any classification, practice, rule, regulation or contract with respect thereto, which is different from that provided in a rate schedule required to be on file with this

iv. Supplemental Answers

(a) MISO Supplemental Answer

182. MISO states that it intends for independent power producers to be able to compete for the 50 ERAS interconnection request spots regardless of whether the independent power producer's proposed interconnection request includes an agreement with an LSE.[461] MISO states that each of the proposed carve out groups are separate from each other and independent power producers may submit interconnection requests in each group.[462] MISO states that independent power producers without agreements with LSEs that submit interconnection requests to ERAS will first be counted towards the 10 independent power producer-only ERAS interconnection request carve out before being counted to the 50 ERAS interconnection request slots shared with LSEs serving non-retail choice loads.[463]

183. MISO states that the Revised ERAS Proposal is crafted to ensure that all interconnection customers can submit interconnection requests to ERAS for all states in the MISO footprint.[464] MISO explains that the carve out for independent power producers provides a safety net for independent power producers to ensure that they have access to at least 10 spots. MISO further explains that it adopted this carve out in the Revised ERAS Proposal to address stakeholder concerns that independent power producers could be precluded from participating in ERAS by LSEs fully subscribing the cap before independent power producers could submit their interconnection requests or by LSEs refusing to execute agreements with independent power producers.

184. MISO acknowledges that some commenters continue to interpret the proposed Tariff language in GIP section 3.9.2 as capping the number of ERAS interconnection requests that may be submitted by independent power producers, that do not have an agreement with an LSE, to 10. Therefore, MISO states that it would welcome a

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Commission unless otherwise specifically provided by order of the Commission for good cause shown.")).

[461] MISO Supplemental Answer at 3.

[462] *Id*. MISO also clarifies that ERAS interconnection requests addressing retail choice loads may only apply for the retail choice carve out regardless of the entity submitting the interconnection request.

[463] *Id.* at 4.

[464] *Id.*

compliance directive from the Commission requiring MISO to include in its GIP section 3.9.2, in relevant part, the following clarifying revisions:[465]

> The Transmission Provider will evaluate Expedited Resource Addition Study requests in the order in which they are submitted using the time stamp from submission. The Transmission Provider will limit the maximum number of the ERAS Interconnection Requests studied in the ERAS process to no more than 68 projects total until the sunset date noted in Section 3.9.9. The Transmission Provider has carved out a maximum of 8 Interconnection Requests of the total 68 Interconnection Requests that may be submitted in accordance with 3.9.1.1(iii) to serve retail choice load and ~~a maximum of~~ 10 Interconnection Requests of the total 68 Interconnection Requests that may be submitted by Independent Power Producers (IPPs) with agreements with entities other than Load Serving Entities to ERAS until the sunset date noted in Section 3.9.9. The remaining 50 Interconnection Requests of the total 68 Interconnection Requests may be submitted by IPPs or Load Serving Entities (LSEs) to serve non-retail choice load. Interconnection Requests submitted by IPPs with agreements with entities other than LSEs to ERAS will be counted first towards the 10 Interconnection Requests cap of the total 68 Interconnection Requests before the 50 Interconnection Requests to serve non-retail choice load. After the 10 Interconnection Requests submitted by IPPs with agreements with entities other than LSEs are accepted by the Transmission Provider, any subsequent Interconnection Request submitted by IPPs will count toward the remaining 50 Interconnection Requests to serve non-retail choice load.[466]

(b) Additional Supplemental Answers

185. Vistra states that it supports MISO's proposed Tariff language regarding the carve out for independent power producer interconnection requests and asserts that the Commission should direct MISO to adopt such language on compliance. However, Vistra reiterates its argument that the timeline for independent power producers contracting with non-LSEs is too aggressive for such independent power producers to meaningfully participate in ERAS. Specifically, Vistra states that independent power producers contracting with non-LSEs would have to obtain an executed agreement and a RERRA verification by August 11, 2025, which is only days after the requested effective

[465] The strikeout text represents MISO's proposed deletions while the underlined text represents MISO's proposed additions.

[466] MISO Supplemental Answer at 5-6.

date for the instant filing.[467] Vistra contends that this timeline will result in the ten ERAS interconnection spots for independent power producers contracting with non-LSEs to be immediately filled by projects in states that can provide RERRA verifications immediately or by smaller projects that can complete applications quickly.[468] Vistra argues that MISO provides no explanation for its position that extending the timeline for independent power producers contracting with non-LSEs is impractical and burdensome.[469] Vistra further argues that adjusting the timeline would have no effect on the other categories of ERAS interconnection requests or the overall pace of ERAS and that adjusting the timeline would make ERAS more effective.[470]

186. Clean Grid Alliance argues that the MISO Supplemental Answer and proposed Tariff language demonstrates that the Revised ERAS Proposal violates the FPA's competition mandates. Clean Grid Alliance asserts that MISO has not addressed why 10 ERAS interconnection requests are reserved for independent power producers, while 50 ERAS interconnection requests are reserved for LSEs.[471] Clean Grid Alliance further contends that MISO has not addressed the potential for LSEs to unilaterally veto contracts with an independent power producer that apply for the 50 ERAS interconnection requests spots and instead prioritize their own generation resources for ERAS.[472] Clean Grid Alliance argues that the Revised ERAS Proposal lacks a requirement for RERRAs to openly consider proposals from independent power producers, allowing unilateral and unchecked applications by LSEs.

187. Michigan Commission argues that a "retail choice load" and "retail choice state" should be considered separate and distinct classifications for ERAS purposes. Michigan Commission notes that retail choice accounts for a very small portion of the state's electrical supply in the state of Michigan. Michigan Commission asserts that treating all

[467] Vistra Answer at 4- 5.

[468] *Id.* at 6.

[469] *Id.* (citing MISO Answer at 20; Witmeier Docket No. ER25-1674 Rebuttal Testimony at 7-8).

[470] *Id.* at 6-7.

[471] Clean Grid Alliance Second Answer at 1; *see also* Clean Grid Alliance Third Answer at 1-2.

[472] Clean Grid Alliance Second Answer at 2.

interconnection requests originating in Michigan as falling under the umbrella of a "retail choice state" is a clumsy simplification that would lead to unjust outcomes.[473]

188. Michigan Commission notes that in MISO's answer and the MISO Supplemental Answer, MISO uses the terms "retail choice states" and "retail choice load" interchangeably in a number of instances.[474] Michigan Commission compares this to MISO's statements in its transmittal, where MISO offered clear distinction between the terms.[475] Michigan Commission explains that Michigan statutory limitations prevent retail choice from exceeding 10% of an electric utility's average weather-adjusted retail sales.[476] Michigan Commission contends that classifying all interconnection requests from the state of Michigan as being located in a "retail choice state," as opposed to classifying each interconnection request based on whether it serves "retail choice load," would severely limit participation from interconnection requests located in Michigan.

189. Michigan Commission requests that the Commission clarify that interconnection requests serving "retail choice load" located in Michigan would be included in the eight-interconnection request retail choice carve out, but that the other 90% of the Michigan load will be eligible to participate in the 10-interconnection request independent power producer carve out or 50-interconnection request "non-retail choice" cap.[477]

190. Invenergy and Clean Grid Alliance raise concerns about certain information included in MISO's "Informational Guide" issued to stakeholders, which states in part that "[a]greements that are not legally binding, such as Letters of Intent, Memorandums of Understanding, or Term Sheets, will not be considered sufficient to meet the off-take agreement requirement."[478] Invenergy argues that this restriction violates the proposed

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[473] Michigan Commission Answer at 3.

[474] *Id.* at 4-5 (citing MISO Supplemental Answer at 3; MISO Answer at 13).

[475] *Id.* at 5-6 (citing Transmittal at 8, 52-53).

[476] *Id.* at 6-7.

[477] *Id.* at 7.

[478] Invenergy Answer at 3-5 (citing MISO, *Expedited Resource Addition Study*, at 7 (posted July 11, 2025), https://cdn.misoenergy.org/ERAS%20Informational%20Guide707493.pdf ?v=20250711150053); Clean Grid Alliance Third Answer at 2-3 (citing same). Invenergy also attaches the ERAS Informational Guide as Exhibit A to its answer.

Tariff language and MISO's statements in this proceeding.[479] Both Invenergy and Clean Grid Alliance also argue that not allowing letters of intent and similar contracts to be included within the scope of "other agreements" under the proposed Tariff[480] raise a barrier to independent power producer participation in ERAS.[481]

(c) MISO Second Supplemental Answer

191. MISO states that any conflation of the terms "retail choice load" and "retail choice state" in its answers was inadvertent. MISO states that the Michigan Commission's understanding, that ERAS interconnection requests serving retail choice load located in Michigan would be included in the eight ERAS interconnection request carve out for retail choice, is correct. MISO further explains that interconnection requests intending to serve the remaining 90% of Michigan load can apply to the 10 ERAS interconnection request spots for independent power producers or the 50 ERAS interconnection request spots for non-retail choice loads.[482]

c. Commission Determination

192. MISO has proposed several eligibility requirements for the ERAS process. We accept these requirements and find them to be just and reasonable and not unduly discriminatory or preferential. Taken together, this comprehensive package of eligibility requirements will deter speculative interconnection requests from entering the ERAS process and minimize disruption to DPP interconnection requests.

193. At the outset, we review the Commission's consideration of open access matters in the context of Order Nos. 888 and 2003. In Order No. 888, the Commission first required open access requirements on a generic basis to address potential discrimination on the transmission system. By requiring an open access transmission tariff, the Commission applied–generically–a comparability standard to jurisdictional transmission providers as it had done previously on a case-by-case basis.[483] Under the comparability standard,

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[479] *Id.* at 4-5.

[480] *See* MISO, Proposed Tariff, attach. X (GIP) (175.0.0), § 3.9.1(2)(d).

[481] Invenergy Answer at 4; Clean Grid Alliance Third Answer at 3.

[482] MISO Second Supplemental Answer at 2-3.

[483] The Commission therefore required "that all public utilities must offer . . . services on a non-discriminatory open access basis" and explained that "[a]n open access tariff that is not unduly discriminatory or anticompetitive should offer third parties access on the same or comparable basis, and under the same or comparable terms and

transmission service was to be offered to third parties on the same or comparable basis as that used by the transmission provider.[484] To implement its requirements, the Commission issued with Order No. 888 a *pro forma* open access transmission tariff and required public utilities to meet the new *pro forma* tariff non-price minimum terms and conditions.[485]

194. In Order No. 2003, the Commission applied Order No. 888's open access requirements to the generator interconnection process in recognition of the fact that generator interconnection is a "critical component of open access transmission service and thus is subject to the requirement that utilities offer comparable service under the [*pro forma* open access transmission tariff]."[486] The Commission found that it was appropriate to establish a standard set of generator interconnection procedures to "minimize opportunities for undue discrimination and expedite the development of new generation, while protecting reliability and ensuring that rates are just and reasonable."[487] To this end, the Commission adopted the *pro forma* LGIP and *pro forma* LGIA and amended its regulations to require all transmission providers to incorporate these standard procedures and agreement into their tariffs.[488]

195. More recently, the Commission rejected MISO's Initial ERAS Proposal because, first, it "place[d] no limit on the number of projects that could be entered in the ERAS process," and second, MISO did "not sufficiently describe how the ERAS process is sufficiently targeted to study only interconnection requests needed to meet the anticipated shortfall in generating."[489] Here, we find that MISO's Revised ERAS Proposal sufficiently addresses these concerns identified in the May 2025 Order by capping the number and size of ERAS projects, strengthening the RERRA verification requirement, requiring ERAS interconnection requests to be located in the same Local Resource Zone as the resource adequacy or reliability need that it will address, absent reasonable

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conditions, as the transmission provider's uses of the system." Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,647 (quoting *Am. Elec. Power Serv. Corp.*, 67 FERC ¶ 61,168, at 61,489 (1994)).

[484] *Id.*

[485] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at app. D, para. 13.6.

[486] Order No. 2003, 104 FERC ¶ 61,103 at PP 9, 12.

[487] *Id.* P 11.

[488] *See* 18 C.F.R. 35.28(f)(1) (2024).

[489] May 2024 Order at P 199-201.

exceptions, and making additional changes, as discussed further below. Collectively, these changes ensure the ERAS process is sufficiently limited in scope to swiftly address discrete, demonstrated resource adequacy needs in a narrowly tailored fashion, and on a temporary, time-limited basis. Additionally, we note that the limited, one-time design of the process weighed significantly on our decision here.

196. While interconnection requests that qualify for the ERAS process will have the ability to interconnect on a priority basis, ERAS does not present open access concerns because it is "open, competitive, technology/fuel agnostic, and does not involve MISO favoring or selecting certain projects over others."[490] The Revised ERAS Proposal also applies identical eligibility criteria across all potential interconnection requests. This is similar to the PJM RRI construct, which allows for potential inclusion of any resource regardless of technology.[491] Furthermore, the Revised ERAS Proposal does not restrict or change interconnection customers' access to the DPP process.

197. We note that MISO's specific requirements for ERAS interconnection requests (e.g., location information for the load the ERAS interconnection request will serve, the limitation on the size of ERAS interconnection requests based on the identified resource adequacy shortfall, specific commercial readiness requirements, etc.), strengthened RERRA verification requirements, and MISO's commitment to publicly post detailed information about each ERAS interconnection request and its corresponding type of load served, establishes a clear and transparent process. Therefore, we disagree with protesters that MISO's Revised ERAS Proposal lacks objective and transparent criteria for participation in ERAS.

(a) RERRA Verification Requirement

198. We find that the proposed RERRA verification requirement is just and reasonable and not unduly discriminatory or preferential. We find that MISO has demonstrated that its proposal to require RERRAs to verify that either: (i) the new, incremental load addition is valid and not otherwise included in a resource plan or other process under the RERRA's purview, or (ii) that the generating facility will address a resource adequacy deficiency, is just and reasonable and not unduly discriminatory or preferential.[492]

199. We agree with MISO that the proposed RERRA verification requirement provides the necessary flexibility to recognize the different regulatory review processes across the

[490] Transmittal at 32.

[491] PJM RRI Order, 190 FERC ¶ 61,084 at PP 118, 121, 123.

[492] *See* Transmittal at 2.

states and RERRAs in the MISO region.[493] MISO has strengthened what was a "notification" requirement in its Initial ERAS Proposal to better ensure that RERRAs affirmatively verify interconnection requests will address specific resource adequacy needs that are not otherwise being addressed. We also find that it is reasonable and appropriate for MISO to allow RERRAs to determine which projects should be selected for ERAS, and to implement their own processes for making such determinations, as this approach strikes a reasonable balance between state authority over resource procurement and Commission authority over generation interconnecting to the interstate transmission system. Accordingly, we find that it is not necessary for MISO to establish scoring criteria or a ranking process for proposed ERAS projects, as protesters suggest. We note that here, we must evaluate whether MISO's Revised ERAS Proposal before us is just and reasonable, and we need not consider alternative proposals. Further, we agree with MISO that RERRAs are uniquely positioned to evaluate the needs in their regions and projects proposed by a developer or LSE[494] and that the Revised ERAS Proposal strikes a reasonable balance between ensuring that an ERAS interconnection request will serve a valid new load or meet a resource adequacy deficiency in MISO while respecting the state's jurisdiction over their own resource mix to address resource adequacy.[495] We disagree with EPSA, Invenergy, and other protesters[496] that state regulators, which are obliged to serve the public interest in accordance with state law, will not be objective in their RERRA verifications. We further find that MISO's reliance on RERRAs in the selection process for ERAS is a practical and expedient solution for each RERRA to identify ways to meet their specific resource adequacy challenges. We note that, as MISO explains, studying an interconnection request through the ERAS process does not pre-determine the outcome of an ERAS interconnection request, as any project must still obtain state approval through the state's corresponding regulatory review process.[497] As several commenters explain, the RERRA verification process balances MISO's need to verify projects that meet resource adequacy needs and the RERRAs' need to not prejudge generation certifications.[498]

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[493] MISO Answer at 24-25.

[494] *Id.* at 22.

[495] *Id.* at 25-26; Southern Regulators Comments at 3.

[496] *Supra* at P 59, P 118.

[497] *See* Transmittal at 31.

[498] Louisiana and Mississippi Commissions Comments at 10; Otter Tail Comments at 4; Texas Commission Comments at 8.

200. We disagree with arguments that the RERRA verification requirement restricts open access by unduly discriminating against interconnection customers in retail choice jurisdictions, such as Illinois and Michigan. Rather, the Revised ERAS Proposal is available to interconnection customers regardless of whether they propose to operate in retail choice or non-retail choice jurisdictions. As MISO explains, the Revised ERAS Proposal was designed to be flexible to accommodate the various RERRA processes and regulatory constructs in the MISO region.[499] Further, the Revised ERAS Proposal adopts a carve out for eight interconnection requests serving retail choice loads (more than 10% of the total number of ERAS interconnection requests allowed under the program) to be studied in ERAS, which was added for the specific purpose of accommodating retail choice loads. Indeed, the Revised ERAS Proposal affords significant flexibility to accommodate interconnection customers in retail choice regions, including by permitting them to participate in ERAS without RERRA verification– a structural accommodation designed specifically to enable retail choice states and regions to participate fairly.[500] We also acknowledge that a significant majority of MISO's load is served through traditional vertically integrated processes.[501] Regarding Michigan Commission's request that MISO remove the proposed Tariff language in GIP section 3.9.1 that RERRA verification can be supported by "a state energy forecast, or other forward-looking forecast," we agree with MISO that the Tariff language is simply included as part of a list of potential information that RERRAs may use and that each RERRA will ultimately determine what information will be required for the ERAS project verification.[502]

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[499] *See* MISO Answer at 25.

[500] Witmeier Testimony at 35-36. We note that Michigan Commission raises concerns with imprecise language in MISO's Answer and MISO's Supplemental Answer regarding retail choice loads and retail choice states; however, we find the proposed Tariff language, as revised by MISO's Supplemental Answer, is clear that the carve out for eight ERAS interconnection requests is for retail choice loads, which would include the 10% limit in Michigan, and the remaining ERAS interconnection requests slots are for non-retail choice load. Further, we note MISO's affirmation of this interpretation, and its explanation that interconnection requests serving the remaining 90% of load in Michigan can apply to ERAS under the 10 ERAS interconnection request spots for independent power producers or the 50 ERAS interconnection request spots for non-retail choice load. MISO Second Supplemental Answer at 2-3.

[501] Transmittal at 22 (citing *Midcontinent Indep. Sys. Operator, Inc.*, 162 FERC ¶ 61,176 at P 67).

[502] MISO Answer at 24.

201. We find unpersuasive protester arguments that the RERRA verification is more difficult to satisfy for certain subcategories of interconnection requests. The record does not demonstrate that certain classes of interconnection customers will necessarily find it more difficult to receive a RERRA verification. RERRA verification may be triggered in numerous ways, not just through participation in one specific state-sponsored process. MISO's proposed GIP section 3.9.1.1 provides that the RERRA verifies that there is a valid, new incremental load addition that is not incorporated in relevant plans or that the proposed generating facility will address an identified resource adequacy deficiency; thus, MISO permits flexibility in satisfying this requirement.[503]

202. Further, we agree with MISO that the precedent in *Xcel* does not require rejection of the Revised ERAS Proposal. First, we note that *Xcel* involved the tariff of a non-independent transmission provider, and the Commission gives such transmission providers less flexibility than RTOs/ISOs to depart from the *pro forma* generator interconnection procedures and *pro forma* generator interconnection agreement.[504] Additionally, the proposal in *Xcel* required an interconnection customer taking part in a state-sponsored bidding process to drop out of the generator interconnection queue if the customer did not win the contract.[505] The *Xcel* proposal also appeared to allow projects submitted as part of the state process to jump ahead of other projects in the queue that were filed first.[506] In contrast, the Revised ERAS Proposal, though it provides an expedited process for certain interconnection requests, does not replace or interfere with the existing DPP process, which remains available to all interconnection requests.

(b) ERAS Cap and Carve Outs

203. We find that MISO's proposal to limit the total ERAS participation to 68 interconnection requests, with a carve out of eight interconnection requests to serve retail choice load and 10 interconnection requests for independent power producers, is just and reasonable and not unduly discriminatory or preferential. We agree with MISO that the Revised ERAS Proposal is narrowly tailored to meet MISO's near-term resource

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[503] MISO, Proposed Tariff, attach. X (GIP) (175.0.0), § 3.9.1.1(a)-(d).

[504] *See* Order No. 2003, 104 FERC ¶ 61,103 at P 26 (allowing RTOs/ISOs to submit LGIP and LGIA terms and conditions that meet an "independent entity variation" standard, which is more flexible than the "consistent with or superior to" and "regional differences" standards). As discussed *supra* in part IV.B.2(c), the parameters of the RERRA verification requirement are clearly stated in MISO's Proposed Tariff.

[505] *Xcel*, 106 FERC ¶ 61,260 at P 22.

[506] *Id*.

adequacy and/or reliability needs.[507] We find that the Revised ERAS Proposal, including the proposed cap and carve outs, strikes a reasonable balance between ensuring broader participation and addressing the resource adequacy needs of the region, while providing reasonable limitations on the number of interconnection requests that will be studied through the ERAS process. Additionally, the proposed cap minimizes the potential for the types of delays that have occurred in the DPP queue to also manifest in the ERAS queue. MISO developed the 68 interconnection request cap in response to the May 2025 Order to limit ERAS participation to a manageable number of interconnection requests that MISO determined it can efficiently study in the short-term consistent with what the Commission approved for PJM's RRI process by design, with adjustments made to accommodate retail choice states and independent power producers in the MISO footprint.[508] Specifically, MISO explains that they coupled the cap with the two respective carve outs to ensure that independent power producers and entities in retail choice states have the exclusive opportunity to participate in ERAS. Therefore, we disagree with protesters' arguments that MISO's proposed cap and carve outs are arbitrary and unsupported.

204. We disagree with protesters' arguments that MISO's proposed cap and carve outs impede open access. Rather, as discussed above, we find that the proposed ERAS process is "open, competitive, technology/fuel agnostic, and does not involve MISO favoring or selecting certain projects over others."[509] Additionally, we find that the carve outs for independent power producers and entities in retail choice states ensure that all interconnection customers will have comparable ability to seek to participate in the ERAS process, regardless of location and ownership type.[510] We also find that MISO's proposed cap is directly responsive to the Commission's concerns in the May 2025 Order that the Initial ERAS Proposal was not just and reasonable because it placed no limit on the number of projects that could be entered in the ERAS process.[511] Our acceptance of

[507] Transmittal at 35, 47.

[508] MISO Answer at 13.

[509] *See supra* P 190.

[510] *See* PJM RRI Order, 190 FERC ¶ 61,084 at P 123 (finding that PJM's proposal does not violate open access requirements because it provides all interconnection customers the comparable ability to submit an interconnection request for projects with at least 10 MW UCAP to be evaluated under PJM's proposed criteria). *See also* CAISO IPE Order, 188 FERC ¶ 61,225 at P 94 (finding that CAISO's proposal does not present open access issues because all interconnection customers are provided a "comparable ability" to join the cluster).

[511] May 2025 Order, 191 FERC ¶ 61,131 at P 199.

MISO's proposal, including the proposed cap of 68 interconnection requests, is consistent with that precedent.

205. We also disagree with protesters' contention that the Revised ERAS Proposal unduly discriminates against independent power producer interconnection requests with non-LSE agreements. In its answer, MISO provides clarification that the 10 ERAS interconnection request carve out for independent power producers with non-LSE agreements is not a cap on independent power producer interconnection requests, and independent power producers may *also* submit interconnection requests in the general group of 50 ERAS interconnection requests.[512] MISO explains that the purpose of the carve out is to address claims that LSEs could block independent power producers from participating in the ERAS process. We disagree with Clean Energy Associations' arguments that it is unclear whether independent power producers can compete on equitable terms for the general group of 50 spots in ERAS because MISO's proposed Tariff language is not clear on the types of agreements it will accept for those spots. MISO's proposed GIP section 3.9.1.2, which details the various types of acceptable executed agreements, applies to all ERAS interconnection customers regardless of whether they apply for the general 50 spots or the carve out spots for independent power producers and retail choice loads. Further, in its supplemental answer, MISO provides additional detail and sample Tariff provisions to clarify the carve out for independent power producers and states that it would welcome a directive to include such language in its Tariff on compliance.[513] We find that the Tariff provisions described by MISO in its supplemental answer will provide clarity to its Tariff. Therefore, we direct MISO to submit, within 30 days of the date of this order, revisions to its Tariff to incorporate the clarifying language included in its supplemental answer.

206. We further disagree with protesters' arguments that MISO should delay the implementation date, or otherwise provide more time, for independent power producer interconnection requests. Rather, we agree with MISO that creating separate start dates for different groups of ERAS interconnection requests may be impractical, administratively burdensome, and inappropriate.[514] Further, we find that MISO's proposed carve out to accommodate 10 independent power producer interconnection requests, in addition to MISO's clarification that independent power producer interconnection requests may also be included in the general group of 50 ERAS interconnection requests, ensures that independent power producers have comparable

[512] MISO Answer at 19.

[513] MISO Supplemental Answer at 4.

[514] MISO Answer at 20-21.

access to ERAS.[515] We therefore do not agree with protesters that additional processes for independent power producer interconnection requests are necessary to render the proposal just and reasonable.

(c) Other ERAS Eligibility Requirements

207. We find that the proposed ERAS executed agreement requirement is just and reasonable and not unduly discriminatory or preferential. Protesters argue that, to satisfy this requirement, the options for independent power producers necessarily require more effort than the self-supply option for LSEs.[516] We disagree that this potential distinction renders MISO's proposal unjust and unreasonable and find that MISO's proposal strikes a reasonable balance between reducing speculative projects and ensuring that certain types of interconnection requests or interconnection customers are not excluded from participating in ERAS. We find that the executed agreement requirement will help ensure that only truly "shovel ready" projects are proposed. As MISO states, this requirement ensures that some form of commercial arrangement exists pairing the ERAS project with the specified load and demonstrates that the ERAS project is not merely submitted in the hope of being selected to serve that need,[517] which would not support the objective of identifying more commercially ready projects in ERAS. We note that LSEs that meet the executed agreement requirement through a commitment to self-supply must still be verified by a RERRA, as is the case with the other types of executed agreements that independent power producers may use. We agree with MISO that this requirement prevents participation by speculative entities that "do not have buy in from the need driver."[518] Consequently, we agree that the proposed Tariff language indicates greater commercial readiness, thereby ensuring ERAS projects can meet MISO's urgent, near-term reliability and resource adequacy needs. While protesters may object to this requirement, MISO provides multiple options for interconnection customers to satisfy the executed agreement requirement.[519]

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[515] *Id*. at 19 (citing Witmeier Docket No. ER25-1674 Rebuttal Testimony at 6-7); MISO Supplemental Answer at 4.

[516] *See, e.g.,* Clean Energy Associations Protest at 31; Clean Grid Alliance Protest at 26-27; EPSA Comments at 5; PIOs Protest at 5.

[517] Transmittal at 30-31.

[518] Witmeier Testimony at 42.

[519] MISO, Proposed Tariff, attach. X (GIP) (1750.0), § 3.9.1.2.

208. One such option is the eligibility of interconnection requests with "other agreements" to be included in the ERAS process.[520] By including such an option, MISO provides considerable flexibility for interconnection customers, including independent power producers and RERRAs seeking to procure supply from independent power producers, to satisfy this requirement.[521] We disagree with Clean Energy Associations that it is unclear which agreements apply to the 50 ERAS interconnection spots because the executed agreement requirements of proposed GIP section 3.9.1.2 apply to all ERAS interconnection requests. Further, as noted by both MISO and protesters, CAISO's IPE,[522] PJM's RRI,[523] and the 2024 MISO Queue Cap[524] proposals all incorporate aspects that encourage commercial readiness and, in each of those proceedings, the Commission found that those proposals were not in violation of open access requirements or otherwise unduly discriminatory. We find here that the Revised ERAS Proposal is largely consistent with these proposals, and likewise just and reasonable.

209. Finally, we find that the executed agreement requirement is tailored to achieve MISO's expressed objective for proposing ERAS, that is, meeting urgent, near-term resource adequacy or reliability needs by requiring interconnection customers to have

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[520] *Id.* § 3.9.1.2(d). In response to stakeholder feedback that the executed agreement requirement may prove too onerous, MISO added this option to establish "a minimum requirement that an arrangement exists between the driver of the need and the project to address that need." Witmeier Testimony at 42.

[521] We disagree with Invenergy's and Clean Grid Alliance's arguments that agreements that are not legally binding should satisfy the "other agreement" requirement, as that would have the effect of rendering the "other agreement" requirement meaningless, thereby allowing projects that may not actually be needed to meet an identified resource adequacy need to be included in the ERAS process.

[522] CAISO IPE Order, 188 FERC ¶ 61,225 at P 174 ("[W]e find that CAISO's proposal to account for commercial interest in its evaluation of interconnection requests will help enable CAISO to prioritize the study of the most viable and needed interconnection requests under Cluster Study Criteria.").

[523] PJM RRI Order, 190 FERC ¶ 61,084 at P 155 ("We find PJM's proposed commercial operation date viability criteria . . . reasonably prioritize projects that have a reasonable likelihood of coming online in the near term to meet PJM's resource adequacy needs.").

[524] January 2025 Order, 190 FERC ¶ 61,057 at P 90 ("We also find that . . . [t]hese exempted interconnection requests [which count first towards the MW cap] are associated with generating facilities that are already in service or already have an executed GIA and, therefore, demonstrate a higher degree of commercial readiness.").

entered into agreements to serve specific load needs.[525] MISO has adequately demonstrated that this executed agreement eligibility criterion, along with the RERRA verification requirement, will help ensure that "shovel ready" projects that can meet RERRA-identified, near-term capacity needs are included in the ERAS process. Further, we find that MISO has provided consistent terms and conditions (and multiple avenues) for satisfying this requirement, and the record does not demonstrate that independent power producers, as a class, will be unable to satisfy this uniform requirement.

210. We find that MISO's proposed application fee, site control, milestone, commercial operation date, and Local Resource Zone requirements for ERAS interconnection requests are just and reasonable and not unduly discriminatory or preferential.[526] We agree with MISO that the proposed requirements will help prevent speculative projects from applying to the ERAS process, which will help ensure "shovel ready" projects that meet specific, near-term resource adequacy needs will be studied. While commenters argue that certain requirements, such as milestone payments, could be made more rigorous or stringent to better deter speculative projects from applying to the ERAS process, the Commission is not obligated to consider whether the ERAS proposal is more or less reasonable than other alternatives.[527] We note, however, that even if some protesters would prefer more stringency, the proposed ERAS application fee, site control, milestone, and commercial operation date requirements are all considerably stricter than those established for the DPP and thus designed to strictly limit participation in the ERAS process, which is both appropriate and consistent with MISO's objectives. Further, while other protesters argue that, for example, the $100,000 application fee and withdrawal penalties could be a barrier for them to enter ERAS,[528] we find that these requirements serve as meaningful deterrents against speculative projects.

211. Additionally, with ERAS, like PJM's RRI and CAISO's IPE proposals, MISO has tailored the requirements toward the goal of satisfying near-term reliability and resource adequacy needs by emphasizing "shovel readiness" and commercial readiness. Taken as a whole, MISO has proposed requiring ERAS interconnection customers to post greater financial and non-financial commercial readiness requirements and greater site control requirements, compared to DPP interconnection customers, as well as an NRIS requirement and RERRA verification and executed agreement requirements. We find

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[525] PJM RRI Order, 190 FERC ¶ 61,084 at P 123; CAISO IPE Order, 188 FERC ¶ 61,225 at P 94.

[526] *Supra* PP 36, 38.

[527] *Supra* P 31.

[528] Clean Energy Associations Docket No. ER25-1674 Protest at 19; Clean Grid Alliance Protest at 79.

that, taken together, MISO has proposed a comprehensive package of eligibility requirements that will considerably deter speculative projects from applying to the ERAS process.

212. We disagree with protesters' arguments that MISO's proposed requirement that an ERAS interconnection request's level of requested interconnection service be no more than 150% of the identified MW need is unduly discriminatory. In the May 2025 Order, the Commission rejected MISO's Initial ERAS Proposal because it was not narrowly-tailored to ensure that only those resources capable of addressing identified near-term resource adequacy or reliability needs would be eligible for expedited study through the ERAS process.[529] We find that capping ERAS interconnection requests at 150% of the identified resource adequacy need is responsive to the May 2025 Order. MISO's proposal caps the ratio of interconnection service requested to needed generation in order to prevent gaming of the ERAS process, where the MW of a potential ERAS request could far exceed the identified MW need for new generation. Without such a cap, the ERAS request could be oversized and even a small MW need could be used for large new generating facilities to bypass the normal queue. MISO's proposal, as it states, is fuel-type agnostic, meaning there are no prohibitions on any specific fuel type from entering the ERAS process and that MISO does not take into account what type of generating facility is associated with an ERAS interconnection request. To the extent that an ERAS project would benefit economically from obtaining interconnection service over and above what is needed to address the RERRA-verified resource adequacy need, that project may seek additional interconnection service through the DPP process.[530] We acknowledge that there are practical limitations on what types of projects can compete for the ERAS process. However, we find that in this instance, where the ERAS process is limited to a small number of projects, and those projects are identified to meet a very specific need, MISO's proposal to ensure that there is a limitation to avoid any gaming concerns is a reasonable protection to put into place. As a result of this limitation, we disagree with protesters that the Local Resource Zone requirement is unduly discriminatory.[531] As noted above, MISO's addition of this requirement helps address the Commission' concern in the May 2025 Order that the ERAS proposal might not be tailored to addressing specific resource adequacy needs. Further, neither LSE nor independent power producer projects will be limited by this zonal requirement if they are included in an integrated resource plan. We find that MISO's Revised ERAS Proposal is therefore just and reasonable and not unduly discriminatory or preferential.

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[529] May 2025 Order, 191 FERC ¶ 61,131 at P 202.

[530] Transmittal at 44; Witmeier Testimony at 68.

[531] *Supra* P 171.

4. ERAS Study Process

a. MISO's Filing

213. MISO proposes to study ERAS interconnection requests quarterly in a regional, serial "first-come, first-served" fashion using the existing engineering study process used in the DPP for ensuring full generator deliverability to load.[532] MISO explains that while both ERAS and DPP studies will use the same MTEP base case (i.e., the most current MTEP base case at the time of the DPP study cycle or the ERAS quarterly study process kickoff), they will include different generator assumptions. Specifically, MISO explains that, while the DPP will continue to include all prior-queued interconnection requests in base case models, the ERAS study will include only generating facilities with an executed GIA in such models.[533]

214. MISO states that the serial study is a key feature of ERAS and that it affords ERAS interconnection requests a better understanding of their impact on the transmission system when looking to address the needs of load. MISO also states that the traditional challenges related to reviewing interconnection requests on a serial basis are not present with ERAS because there will be a smaller number of interconnection requests to process, and they are expected to be geographically and electrically dispersed across the MISO footprint.[534] MISO states that if several ERAS interconnection requests are submitted in one geographical area at the same time, it will study the interconnection requests with the earliest submission time first, and the subsequent interconnection requests will be studied in the next available ERAS quarterly study period. However, MISO states that it does not anticipate this occurring very often due to the 10-interconnection request cap on ERAS interconnection requests per quarterly study period, its large footprint, and the strict eligibility requirements to enter the ERAS process.

215. Additionally, MISO proposes that existing DPP interconnection requests that have not reached Decision Point II in the DPP 2022, 2023, and later cycles will be eligible to transfer to ERAS.[535] MISO states that it is aware of several existing DPP interconnection requests that could apply to participate in ERAS. MISO explains that these DPP interconnection requests may remain in their DPP study group while applying for ERAS, and once admitted to ERAS, the interconnection requests must withdraw from the DPP

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[532] Transmittal at 7-8; Witmeier Testimony at 52.

[533] Transmittal at 39; Witmeier Testimony at 52.

[534] Transmittal at 37-38.

[535] *Id.* at 37.

and will be subject to MISO's automatic withdrawal penalties and harm penalties. MISO asserts that the penalties are necessary because when interconnection requests drop out of the queue, the withdrawal causes harm to other interconnection requests in that study group. MISO explains that if a DPP interconnection request is deemed ineligible for ERAS, then it will forfeit the $100,000 D1 payment required with the ERAS application and will remain in its original DPP queue position.

216. MISO asserts that the Revised ERAS Proposal has been crafted to avoid supplanting the DPP or harming interconnection requests in the DPP interconnection queue.[536] MISO states that it plans to coordinate the ERAS, DPP, and expedited project review studies to maximize efficiency and reduce any impacts among these studies. MISO explains that network upgrades identified in ongoing MTEP studies that mitigate congestion in DPP and ERAS studies will remove the need for DPP and ERAS network upgrades once the MTEP project is approved. MISO contends that ERAS interconnection requests will not harm interconnection requests currently studied in the DPP process by taking existing transmission capacity headroom from active DPP interconnection requests. According to MISO, this is because the ERAS and DPP processes use the same MTEP base case as a starting point, and any headroom used by an ERAS interconnection request is not deducted from the DPP model, as ERAS interconnection requests will not be included in ongoing DPP studies.[537] MISO explains that the output of the DPP and ERAS models will be reconciled in the next MTEP, consistent with how MISO reconciles currently effective parallel processes through the next MTEP base case.[538]

217. MISO further explains that if transmission capacity is overallocated due to approved interconnection requests in both the ERAS and DPP processes, such

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[536] *Id.* at 39.

[537] *Id.* at 42-43; Witmeier Testimony at 52. MISO explains that the DPP process uses the most up-to-date MTEP base case when the DPP study is kicked off and is not subsequently modified to include later-approved MTEP projects or ERAS interconnection requests after that kickoff. Witmeier Testimony at 53. For example, MISO explains that if it approves an ERAS interconnection request that will use the transmission capacity in MTEP 2024, and the DPP 2023 cycle is using MTEP 2023, the ERAS interconnection customer will not take away transmission capacity from any interconnection request in the DPP 2023 cycle. MISO also asserts that ERAS interconnection requests will not have early access to the newly available transmission headroom related to Long Range Transmission Plan Tranche 2.1 projects and will not disadvantage interconnection requests from the DPP 2025 cycle. Transmittal at 43.

[538] Transmittal at 43.

overallocation will be identified and mitigated in the next MTEP cycle.[539] In such a scenario, MISO explains that the transmission capacity overallocation would be discovered as part of the MTEP Deliverability Analysis, which ensures continued deliverability of generating facilities with NRIS.[540] MISO further contends that, even in an overallocation scenario, there will be no negative implications for either a DPP or ERAS interconnection request because both types of interconnection requests will be allowed to proceed, and neither will be required to pay additional costs due to the overallocation. MISO explains that the cost of the MTEP project needed to resolve overallocation will be allocated based on the existing Tariff rules, which will likely allocate the costs of the project to load within the transmission pricing zone where the transmission upgrade is located.[541] MISO explains that this will include the load that is benefiting from the ERAS and DPP interconnection requests, and this load will benefit from the network upgrades that were funded by the interconnection customers that went through those processes. Further, MISO asserts that the cost shift is consistent with existing processes. MISO explains that it has multiple planning processes, many performed in parallel with their own unique modeling assumptions and cost allocation methodologies.[542] MISO states that after projects are approved through their relevant processes, they are included in the base cases of subsequent studies based on the modeling assumptions for those studies. MISO states that it is not uncommon for new constraints to arise in subsequent studies driven by approved transmission and generation projects, as well as new load growth and generation retirement, and that, as new constraints are identified, new mitigation is identified, which could include another new transmission project necessary to ensure reliability.[543]

218. Finally, MISO asserts that the Revised ERAS Proposal meets the standard for an independent entity variation from the requirements of Order Nos. 2003 and 2023 because it fosters the increased development of economic generation by reducing interconnection

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[539] *Id.*; Witmeier Testimony at 54.

[540] Witmeier Testimony at 54.

[541] *Id.* at 54-55.

[542] MISO references, for example, baseline reliability projects, market efficiency projects, multi-value projects, transmission deliverability service projects, interregional transmission projects, other projects, generator interconnection projects, and new generating facilities that are approved through the DPP, generator surplus, or generator replacement processes. *Id.* at 55-56.

[543] *Id.* at 56.

costs and time.[544] MISO asserts that because ERAS is a standalone process, it should be viewed as one large independent entity variation with a defined set of rules, rather than individual independent entity variations for the various differences between the cluster study process outlined in Order Nos. 2023 and 2023-A and the proposed serial-based study approach in ERAS.[545] MISO argues that using serial studies for ERAS accomplishes the purposes of Order Nos. 2003 and 2023 by minimizing the restudy risk that is inherent to multi-phase cluster studies so that ERAS generating facilities can be built quickly, without the risk of cascading restudies.[546] MISO contends that although the use of cluster studies is appropriate for the large queue volume seen in MISO's DPP process, the use of serial studies for ERAS will allow MISO to quickly study ERAS interconnection requests to address resource adequacy and/or reliability concerns and to meet the goals of the temporary ERAS process.

b. Responsive Pleadings

i. Comments in Support

219. Texas Commission argues that the Revised ERAS Proposal will not negatively impact DPP interconnection customers.[547] Texas Commission asserts that allowing interconnection customers in the DPP to transfer their interconnection request to ERAS before Decision Point II protects remaining DPP interconnection requests by preventing unplanned restudies that could result from late-stage transfers. Texas Commission adds that any interconnection requests that transfer from the DPP to ERAS must pay all applicable withdrawal penalties.

ii. Protests

(a) Serial Studies

220. Several protesters raise concerns with MISO's proposal to study ERAS interconnection requests serially. Clean Grid Alliance argues that ERAS represents a high-risk deviation that threatens to create ongoing disruptions to the DPP by destabilizing study models that interconnection customers rely on and causing cost shifts,

[544] Transmittal at 23-24 (citing Order No. 2003, 104 FERC ¶ 61,103 at PP 11-12).

[545] Witmeier Testimony at 5, 67.

[546] Transmittal at 24.

[547] Texas Commission Comments at 11.

resulting in cascading restudies in ERAS and the DPP.[548] Relatedly, Clean Grid Alliance argues that despite MISO's proposal to adopt a cap of 10 ERAS interconnection requests per quarterly study period, the risk of cascading restudies is still present, as with any serial study approach.[549]

221. Invenergy argues that the Revised ERAS Proposal violates Order No. 2023's requirement that interconnection requests be studied in clusters.[550] Invenergy points to the Commission's language in the May 2025 Order that a serial interconnection study process may contribute to delays if multiple interconnection requests are submitted in the same quarter in the same area of the transmission system.[551] PIOs argue that in Order No. 2023, the Commission established the cluster study process as the cornerstone on which other reforms were oriented, and a separate serial study process would lead to unjust and unreasonable rates by diverting resources and causing delays to the existing DPP process, thereby undermining MISO's ability to identify the most efficient set of shared network upgrades for a DPP study group.[552] PIOs state that a serial study process also fails to realize the benefit of the efficient identification of shared network upgrades, and this will result in the under-identification of network upgrades assigned to ERAS interconnection requests, leading to reliance on the MTEP process to identify smaller, but more expensive, discrete technology solutions.[553] PIOs argue that ERAS is also not limited or transitional because its sunset date exceeds the full shift to cluster studies required by Order No. 2023 and may delay the realization of the benefits from Order No. 2023.[554]

222. PIOs argue that the serial study approach will detract staff resources from the DPP and that the Commission has previously denied requests to operate serial studies parallel to cluster studies.[555] PIOs contend that running serial studies for ERAS for multiple

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[548] Clean Grid Alliance Protest at 5.

[549] *Id.* at 16-17.

[550] Invenergy Protest at 17 (citing Order No. 2023, 184 FERC ¶ 61,054 at PP 177-178; Invenergy Docket No. ER25-1674 Protest at 3-6).

[551] *Id.* (citing Order No. 2023, 184 FERC ¶ 61,054 at P 178).

[552] PIOs Docket No. ER25-1674 Protest at 22-23.

[553] *Id.* at 28.

[554] *Id.* at 25.

[555] PIOs Protest at 20 (citing Order No. 2023, 184 FERC ¶ 61,054 at PP 177-178).

years will delay MISO's processing of the DPP for those years.[556] PIOs further argue that MISO's serial study approach for ERAS will result in many network upgrade needs being identified for the first time in the MTEP process and that MISO's use of MTEP to build upgrades for ERAS interconnection requests does not achieve efficient transmission development.[557]

223. Invenergy argues that MISO has not justified the need for ERAS to span multiple study cycles rather than it occurring over one cycle.[558]

224. PIOs argue that MISO's proposed cap of 68 interconnection requests to be studied through the ERAS process does not address how the ERAS quarterly study period timeline will intersect with the DPP process.[559]

(b) Withdrawals

225. Clean Grid Alliance and Invenergy raise concerns about the effects of withdrawals from ERAS. Invenergy states that Order No. 2023 established withdrawal penalties to encourage interconnection customers to submit viable interconnection requests, discourage late-stage withdrawals, and reduce harm to other interconnections customers from withdrawals. Invenergy argues that ERAS does not accomplish the purposes of Order No. 2023 because the non-refundable D1 application fee and refundable M2 payment do not address the risk of restudies and delays nor the harms to other interconnection customers that would result from late-stage withdrawals from ERAS.[560] Clean Grid Alliance argues that interconnection customers in the DPP need an off-ramp without financial penalties when an ERAS interconnection request emerges and creates a negative financial impact.[561]

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[556] *Id.* at 22.

[557] *Id.* at 18.

[558] Invenergy Protest at 14.

[559] PIOs Protest at 17.

[560] Invenergy Protest at 17-18.

[561] Clean Grid Alliance Protest at 23.

226. Clean Grid Alliance argues that if an ERAS interconnection request withdraws, restudies must occur in both ERAS and the DPP.[562] Clean Grid Alliance adds that such withdrawals would also impact the MTEP models because such models include ERAS interconnection requests after an EGIA is executed and a withdrawal after that point would render the MTEP models inaccurate. Further, Clean Grid Alliance asserts that such models are not designed to address interconnection requests.[563] PIOs add that they strongly oppose the creation of a "two-track" system in which ERAS interconnection requests are not fully studied until the MTEP.[564] Further, Clean Grid Alliance avers that if an ERAS EGIA is terminated, then the MTEP models that the DPP utilizes would no longer be accurate.[565]

227. Clean Grid Alliance argues that despite MISO's claims that withdrawals in ERAS will have little impact on DPP interconnection customers, any withdrawal will require restudies and administrative tasks. Clean Grid Alliance also notes that ERAS should consider the impacts to an ERAS interconnection request if the load it is intended to serve does not materialize.[566]

228. Invenergy asserts that MISO has not clarified how the withdrawal of an ERAS interconnection request from the ERAS queue may impact the DPP cluster study and DPP interconnection customers.[567] Invenergy argues that it is not just and reasonable to assign network upgrade costs to interconnection customers that are not the "but for"[568]

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[562] *Id.* at 18. Clean Grid Alliance asserts that MISO's DPP 2023 models may include ERAS projects and that later DPP cycles would certainly include ERAS projects. *Id.*

[563] *Id.* at 17.

[564] PIOs Protest at 17-18.

[565] Clean Grid Alliance Protest at 18.

[566] *Id.* at 20.

[567] Invenergy Protest at 22.

[568] For generator interconnection-related network upgrades identified through the generator interconnection process, the Commission has accepted proposals by RTOs/ISOs to allocate the cost of such network upgrades solely to individual, or clusters of, interconnection customers. Through the generator interconnection process, the transmission provider studies individual or clusters of interconnection requests and identifies specific network upgrades needed to accommodate each interconnection request on an incremental basis (i.e., by determining whether a network upgrade is

cause of those costs, or that do not reflect their contribution to a needed network upgrade. Invenergy asserts that MISO should clarify its approach to ensure interconnection customers are paying for costs that they actually necessitate.

(c) Harm to Interconnection Customers

229. Several protesters argue that the Revised ERAS Proposal will harm DPP interconnection customers because it is a multi-year proposal.[569] They further argue that the Revised ERAS Proposal will delay the DPP because the serial studies in the ERAS process could detract from transmission providers' efforts to efficiently process cluster studies in the DPP and would not ensure reliable, efficient interconnection.[570] Several protesters assert that, unlike MISO's Revised ERAS Proposal, PJM's RRI and CAISO's IPE proposals were one-time, emergency proposals that were narrowly tailored to minimize harm and disruption to other interconnection customers.[571] Clean Grid Alliance further argues that MISO's proposed cap and carve outs are dissimilar from PJM's RRI because projects in PJM's RRI are processed under the same study cycle under PJM's standard interconnection queue, whereas MISO proposes to process ERAS interconnection requests in a separate queue.[572]

230. Several protesters argue that the Revised ERAS Proposal poses significant harm to DPP interconnection customers by diverting needed resources to conduct interconnection studies, such as limited staffing, and contend that implementing ERAS in parallel to the DPP will exacerbate these challenges, delay DPP processing, and increase network upgrade costs.[573] Invenergy asserts that MISO has failed to explain how the establishment

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needed "but for" the interconnection of a generating facility). *See Sw. Power Pool, Inc.*, 122 FERC ¶ 61,060 (2008); *Sw. Power Pool, Inc.*, 171 FERC ¶ 61,272 (2020).

[569] Clean Grid Alliance Protest at 17, 51-53; Invenergy Protest at 20-21; NextEra Docket No. ER25-1674 Protest at 26-27.

[570] Clean Grid Alliance Protest at 16-19; Invenergy Protest at 20; NextEra Docket No. ER25-1674 Protest at 31 (citing Order No. 2023, 184 FERC ¶ 61,054 at PP 177-178, 1347).

[571] MISO IPPs Docket No. ER25-1674 Protest at 7-8 (citing Kelliher Aff. at 5-6); NextEra Docket No. ER25-1674 Protest at 26-27; PIOs Docket No. ER25-1674 Protest at 42-43.

[572] Clean Grid Alliance Protest at 26, 67.

[573] Clean Energy Associations Docket No. ER25-1674 Protest at 31; Clean Grid Alliance Protest, attach. A (Declaration of Jennifer Ayers-Brasher) at 6 (Ayers-Brasher

of a second interconnection queue will not increase the interconnection delays already common in the existing queue.[574] Invenergy states that it applauds MISO for its commitment to hire additional staff to assist with the backlogged queue; however, this could be implemented independent of the ERAS proposal to address existing queue delays. Clean Grid Alliance further argues that MISO has not demonstrated how staffing challenges that have impacted DPP processing are not also present in facilitating ERAS.[575]

231. Clean Energy Associations assert that MISO's promise to prevent resources and staff time devoted to ERAS from being utilized to speed the DPP process is unfair to developers that have been waiting their turn to get through a backlogged queue.[576] Clean Energy Associations argue that, in spite of changes to the MISO proposal, such as the cap on ERAS participation and locational restrictions, ERAS still exists as a parallel process. Additionally, Clean Energy Associations argue that the task of studying ERAS interconnection requests while also studying DPP interconnection requests will further stretch MISO's already strained resources, risking delay to both the ERAS queue and the DPP queue.[577]

232. Clean Grid Alliance contends that a better approach to address large load additions is to allow large loads and interconnection customers to move through the existing processes in a coordinated fashion to create a net-zero impact on resource adequacy.[578]

233. Several protesters argue that the Revised ERAS Proposal allows for queue jumping.[579] PIOs argue that ERAS interconnection requests are effectively jumping the DPP queue, and much of the costs for ERAS interconnection customers to connect to the

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Testimony); MISO IPPs Docket No. ER25-1674 Protest at 23-24; NextEra Docket No. ER25-1674 Protest 31-32; PIOs Docket No. ER25-1674 Protest at 15-16, 22, 26.

[574] Invenergy Protest at 20.

[575] Clean Grid Alliance Protest at 28.

[576] Clean Energy Associations Protest at 23.

[577] *Id.* (MISO, Transmittal Letter, Docket No. ER25-507-000, at 3 (Nov. 21, 2024); Witmeier Testimony at 13).

[578] Clean Grid Alliance Protest at 19.

[579] Clean Energy Associations Protest at 10; MISO IPPs Docket No. ER25-1674 Protest at 24; NextEra Docket No. ER25-1674 Protest at 3, 8, 10, 36, 41; PIOs Protest at 15, 20; PIOs Docket No. ER25-1674 Protest at 1-3, 8-9.

transmission system will be borne by DPP interconnection customers or unaffiliated load.[580] PIOs further argue that MISO's lack of a post hoc analysis to true up costs may result in ERAS interconnection customers paying less than their fair share.[581] PIOs assert that the advantages for projects that make it into ERAS, in addition to the lack of oversight from MISO, will create an incentive for RERRAs to approve as many in-state projects as possible.[582]

234. Clean Energy Associations assert that the Revised ERAS Proposal still allows for queue jumping from MISO's DPP to ERAS and interconnection requests, especially thermal resources proposed by LSEs, to offer additional capacity as surplus to be provided to an affiliate, effectively bypassing the DPP queue a second time.[583]

235. Additionally, Invenergy states that it has concerns that ERAS interconnection requests will have priority over DPP interconnection requests in the existing queue because ERAS interconnection requests will be studied first and can incorporate up-to-date information about available transmission capacity.[584] Invenergy also states that it has concerns about the unintended consequences of using two different base cases for ERAS and DPP interconnection requests that are being studied simultaneously.[585]

(d) Transmission Overallocation

236. Several protesters assert that MISO's Revised ERAS Proposal will allow ERAS interconnection customers to receive earlier access to transmission capacity. Protesters contend that ERAS interconnection requests will be studied faster than DPP interconnection requests, which will necessarily take up transmission capacity from the DPP, leading to increased costs for later queued DPP interconnection requests as ERAS interconnection requests queue jump the DPP.[586] MISO IPPs and NextEra assert that

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[580] PIOs Protest at 15, 20.

[581] *Id.* at 15-16.

[582] *Id.* at 24-25.

[583] Clean Energy Associations Protest at 10.

[584] Invenergy Protest at 20-21.

[585] *Id.* at 21.

[586] Clean Grid Alliance Protest at 43-46; MISO IPPs Docket No. ER25-1674 Protest at 23-24; NextEra Docket No. ER25-1674 Protest at 42-43; 2025 Brattle Group Report at 26-27; PIOs Docket No. ER25-1674 Protest at 8-9,15-16.

once MISO incorporates ERAS interconnection requests with EGIAs into the MTEP model, which MISO has represented will occur for the DPP 2026 cycle, it will reduce the amount of transmission capacity available to DPP interconnection requests and subject those interconnection customers to higher network upgrade costs, potentially threatening the viability of their projects.[587] PIOs, NextEra, and Clean Grid Alliance similarly assert that the ERAS interconnection customers may pay less to interconnect through the ERAS process than if they had been studied as part of the DPP study group because ERAS interconnection requests: (1) will be double-counting the same headroom used by parallel DPP study groups; (2) will be advantaged in their use of existing headroom by excluding prior-queued interconnection requests from their interconnection study; and (3) will be arbitrarily less likely to trigger violations than DPP study groups because they will be evaluated serially and therefore gain disproportionately from existing headroom on the transmission system.[588]

237. MISO IPPs and NextEra further argue that faster study of ERAS interconnection requests may create contingent facilities that DPP interconnection requests are reliant upon, which may be delayed and subsequently harm reliant DPP interconnection requests.[589] Furthermore, Clean Grid Alliance argues that MISO's proposal to study ERAS interconnection requests and existing DPP study groups in parallel could ultimately lead to interconnection customers being subject to limited operations while MISO resolves capacity overallocation through the MTEP process.[590]

238. Several protesters raise concerns regarding reliability issues arising from interactions between ERAS projects and other interconnection customers, as the study model will exclude higher-queued interconnection customers without an interconnection agreement.[591] Clean Grid Alliance further argues that using the MTEP process to later address reliability concerns resulting from transmission capacity overallocation will not effectively address reliability concerns due to the limitations of NRIS and Energy

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[587] MISO IPPs Docket No. ER25-1674 Protest at 24; NextEra Docket No. ER25-1674 Protest at 42-43.

[588] Clean Grid Alliance Protest at 43-46; 2025 Brattle Group Report at 26-27; PIOs Docket No. ER25-1674 Protest at 16.

[589] MISO IPPs Docket No. ER25-1674 Protest at 24-25; NextEra Docket No. ER25-1674 Protest at 43.

[590] Clean Grid Alliance Protest, Ayers-Brasher Testimony at 9.

[591] Clean Grid Alliance Protest at 20 (citing Clean Energy Associations Docket No. ER25-1674 Protest, Aff. of Warren Hess at ¶ 2, (filed Apr. 7, 2025)); NextEra Docket No. ER25-1674 Protest at 44.

Resource Interconnection Service studies.[592] Clean Grid Alliance argues that MISO's proposal to address transmission capacity overallocation through the next MTEP is unreasonable because there is no guarantee that the MTEP will produce the needed transmission, and it would shift ERAS-related costs to MTEP.[593]

239. Clean Energy Associations assert that, as with the Initial ERAS Proposal, the Revised ERAS Proposal fails to include late-stage DPP generating facilities in ERAS studies and will result in reduced network upgrades due to lower line loadings.[594] Clean Energy Associations aver that this will result in reliability gaps because MISO will not model all known near-term system changes that will occur when the ERAS generating facility reaches commercial operation. Clean Energy Associations assert that ERAS already departs from MISO's standard practice and that ERAS interconnection requests will be studied only with interconnection requests that have already achieved a GIA (i.e., interconnection requests from prior DPP cycles or completed ERAS cycles), while DPP interconnection requests will share headroom with all other interconnection requests in the DPP cycle.[595] Clean Energy Associations thus contend that ERAS will effectively push current reliability gaps onto future interconnection requests that are not in ERAS.[596]

240. Clean Energy Associations argue that the use of the annual MTEP reliability study process to resolve over-allocation of transmission headroom across ERAS and the DPP will not effectively address reliability concerns, as the annual MTEP reliability study process sets local balancing area constraints to limit power flows between local balancing areas, masking constraints that would otherwise show up in the DPP process.[597] Clean Energy Associations assert that, if MTEP does not capture the constraints caused by overallocated headroom due to not including all the expected projects coming online at the same time, the resulting unaddressed constraints will fall to subsequent DPP cycles.

241. Furthermore, Clean Energy Associations argue that, even with a numerical cap on the total number of interconnection requests and the number of interconnection requests per zone, ERAS interconnection requests could still trigger significant reliability impacts

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[592] Clean Grid Alliance Protest at 20 (citing Clean Energy Associations Protest, Docket No. ER25-1674, Aff. at P 2).

[593] *Id.* at 22.

[594] Clean Energy Associations Protest at 12, 21.

[595] *Id.* at 12-13.

[596] *Id.* at 13.

[597] *Id.* at 22.

that require substantial network upgrades, if they are large and located in areas where they have a high impact on a highly congested part of the transmission system.[598] Clean Energy Associations assert that the cap on the number of interconnection requests and interconnection requests per zone quarterly does not negate the potential for overlapping allocation of headroom that is insufficiently reconciled via MTEP.

242. Relatedly, NextEra argues that the MTEP process may not be able to resolve issues caused by ERAS because: (1) timing issues between ERAS and MTEP processes may limit the efficacy of the MTEP to prevent costs of network upgrades needed to resolve issues missed in the ERAS process from being passed on to interconnection customers in the DPP; (2) the MTEP and DPP processes use different underlying assumptions, including dispatch assumptions; and (3) MISO assesses deliverability differently in the MTEP and DPP processes.[599]

243. Furthermore, several protesters raise concerns regarding cost allocation for network upgrades that are identified in the MTEP process. MISO IPPs argue that the ERAS study process will not identify the need for required upgrades, possibly leaving customers that entered DPP prior to the ERAS interconnection requests left to foot the bill.[600] Furthermore, MISO IPPs assert that allocating costs for network upgrades triggered by ERAS interconnection requests through MTEP could run afoul of the Commission's cost allocation requirements and be inconsistent with cost causation requirements.[601]

244. Some protesters assert that the Revised ERAS Proposal will violate cost causation principles by allocating costs of such upgrades to load.[602] NextEra states that MISO claims that costs will be allocated to load in the same transmission pricing zone where a network upgrade is located and expects that "this load will include the load that is

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[598] *Id.* at 24.

[599] NextEra Docket No. ER25-1674 Protest at 45 (citing Cody Doll Aff. at 7-9).

[600] Clean Energy Associations Docket No. ER25-1674 Protest at 28-29; MISO IPPs Docket No. ER25-1674 Protest at 23; NextEra Docket No. ER25-1674 Protest at 45-48; PIOs Docket No. ER25-1674 Protest at 19-21.

[601] MISO IPPs ERAS 1.0 Protest at 47.

[602] Clean Energy Associations Docket No. ER25-1674 Protest at 28-29; NextEra Docket No. ER25-1674 Protest at 46-48.

benefiting from the ERAS and DPP interconnection requests;[603] however, NextEra argues that interconnection requests frequently trigger the need for network upgrades in neighboring transmission zones, meaning that transmission customers and ratepayers in one transmission pricing zone may be required to subsidize the costs of serving other transmission customers and ratepayers.[604] NextEra argues that this subsidization may be exacerbated because the claimed need leading to issuance of a RERRA verification for an ERAS interconnection request may be limited to a locality or municipality, but that ERAS interconnection request may eventually create a need for significant upgrades through the MTEP process, requiring a transmission pricing zone to subsidize the cost of upgrades to meet a locality's need.[605] PIOs contend that while there are circumstances in which it is appropriate for load to pay the costs of new transmission rather than generation, that is not the case for the proposed cost shifts driven by ERAS.[606] PIOs argue that the proposed shift in costs driven by ERAS projects to load would be haphazard and would not necessarily ensure that the portion of load that shoulders any such costs is also the portion of load that benefits from the ERAS and DPP generating facilities whose full impact was not captured in their parallel studies.[607] Thus, PIOs argue that the ERAS proposal moves transmission planning in the opposite direction from the Commission's policies established in Order Nos. 1000[608] and 1920.[609]

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[603] NextEra Docket No. ER25-1674 Protest at 47 (citing Witmeier Docket No. ER25-1674 Rebuttal Testimony at 38:5-9).

[604] *Id*. at 47-48.

[605] *Id.* at 48.

[606] PIOs Docket No. ER25-1674 Protest at 21.

[607] *Id.* (citing PIOs Docket No. ER25-1674 Protest, attach. A (Testimony of Houtan Moaveni) at 14-16).

[608] *Id.*; *Transmission Plan. & Cost Allocation by Transmission Owning & Operating Pub. Utils.*, Order No. 1000, 136 FERC ¶ 61,051 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g & clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014).

[609] PIOs Docket No. ER25-1674 Protest at 21; *Bldg. for the Future Through Elec. Reg'l Transmission Plan. & Cost Allocation*, Order No. 1920, 187 FERC ¶ 61,068, *order on reh'g & clarification*, Order No. 1920-A, 189 FERC ¶ 61,126 (2024), Order No. 1920-B, 191 FERC ¶ 61,026 (2025), *appeal docketed sub nom. Appalachian Voices v. FERC*, No. 24-1650 (4th Cir. pet. consolidated Aug. 8, 2024).

245. Clean Grid Alliance argues that MISO's proposal to allow "backfilling" of a quarterly study period is unjust and unreasonable.[610]

iii. Answers

(a) MISO Answer

246. MISO asserts that the Revised ERAS Proposal will not take resources away from DPP processing because it will use the ERAS application fee and study deposit to cover costs related to processing ERAS interconnection requests, including improving study tools and hiring additional staff.[611] MISO further asserts that it has carefully crafted the Revised ERAS Proposal to avoid supplanting the DPP or harming DPP interconnection customers.[612]

247. MISO contends that, as the Commission noted in the PJM RRI Order, arguments that separate study processes like ERAS will harm existing interconnection customers are speculative. MISO asserts that it is not proposing to delay the DPP queue processing schedule as a result of the ERAS proposal, that no DPP milestones have been altered, and that no interconnection customer will lose its queue position.[613] MISO also argues that it has taken steps to ensure that current DPP interconnection requests are protected from losing available transmission capacity.[614] MISO states that it will build the ERAS model based on the existing MTEP model, which will not remove any available transmission system headroom from DPP interconnection requests.[615] MISO explains that ERAS will only incorporate approved generating facilities, while the DPP will incorporate all higher and equally-queued interconnection requests, which includes speculative projects.[616] MISO explains that it will follow its existing processes to determine if already planned projects can alleviate constraints. MISO also argues that by not updating the base case for each DPP cycle once the study process starts, except for changes due to withdrawals

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[610] Clean Grid Alliance Protest at 28.

[611] MISO Docket No. ER25-1674 Answer at 47.

[612] MISO Answer at 29.

[613] MISO Docket No. ER25-1674 Answer at 17 (citing PJM RRI Order, 190 FERC ¶ 61,084 at P 245).

[614] MISO Answer at 29-30; MISO Docket No. ER25-1674 Answer at 39.

[615] MISO Docket No. ER25-1674 Answer at 39-40.

[616] MISO Answer at 2.

or generator retirements, transmission capacity available for DPP interconnection requests is not being taken away by ERAS interconnection requests approved outside the DPP cycle.[617] MISO also argues that using the latest, approved MTEP base case to reconcile the models insulates existing DPP interconnection requests from costs shifts due to the ERAS process. MISO argues that there is no evidentiary support to protesters' arguments that ERAS interconnection requests will result in higher network upgrade costs for DPP interconnection requests and that ERAS requires interconnection customers to pay all network upgrade costs associated with their proposed interconnection requests.[618] MISO further states that network upgrades approved through the ERAS process can be used to mitigate constraints in the DPP process, which will have a positive impact on the DPP.

248. Regarding concerns about whether the ERAS proposal will protect DPP interconnection customers from ERAS interconnection customer withdrawals prior to EGIA execution, MISO asserts that DPP interconnection requests are adequately protected from ERAS withdrawals because an ERAS interconnection request that does not reach EGIA execution will never be modeled in DPP cycles and therefore cannot impact the DPP.[619] Further, MISO asserts that the proposed ERAS study process will ensure that a withdrawal will not cause restudies in the ERAS process, as ERAS interconnection requests will be studied serially, or in the DPP process, as the parallel ERAS and DPP studies are done in tandem. MISO clarifies that a DPP interconnection request that moves to ERAS will be liable for any harm caused to other DPP interconnection requests in the study group and will be subject to automatic withdrawal penalties.

249. In response to concerns about ERAS not being a one-time process, MISO states that it does not want to limit participation to a one-time opportunity if some interconnection customers or RERRAs take more time to identify projects that could participate in ERAS.[620] MISO contends that it would need to do a cluster study for a one-time process, which would prevent interconnection customers from more timely knowing their full network upgrade costs, as those costs would be contingent on the decisions made by all the other ERAS interconnection requests in the cluster.

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[617] *Id.* at 29-30; MISO Docket No. ER25-1674 Answer at 40 (citing Witmeier Docket No. ER25-1674 Rebuttal Testimony at 35).

[618] MISO Docket No. ER25-1674 Answer at 40.

[619] MISO Docket No. ER25-1674 Supplemental Answer at 5.

[620] MISO Docket No. ER25-1674 Answer at 35-36.

250. MISO also argues that the ERAS proposal will not result in queue jumping because the ERAS process is open to all interconnection customers that meet the eligibility criteria, and any interconnection request selected to participate is not similarly situated to other interconnection requests because that request has a greater ability to meet near-term resource adequacy needs.[621] MISO contends that, similar to the Commission's findings when accepting PJM's RRI proposal, no DPP interconnection requests will be displaced by ERAS, no DPP milestones have been altered, and no DPP interconnection customer will lose its queue position as a result of ERAS.[622]

251. MISO states that, because the Revised ERAS Proposal establishes a cap on the number of interconnection request that will be studied under ERAS and will occur over a limited timeframe, the DPP is further protected.[623] MISO asserts that addressing the ongoing delays in the DPP to reach a study processing time of one year remains a priority for MISO, and ERAS is a separate process needed to address near-term reliability and resource adequacy needs.

(b) Additional Answers

252. Clean Grid Alliance argues that MISO's contention that its staffing resources will not be diverted from processing the DPP queue to support the ERAS process is unsupported.[624] Clean Grid Alliance also disagrees with MISO's arguments that the ERAS proposal would not enable queue jumping and states that the Commission has previously rejected such queue jumping proposals.[625]

253. Clean Grid Alliance argues that MISO has not addressed protesters' arguments that ERAS will harm DPP interconnection customers through disrupting modeling, causing cascading restudies, and shifting costs.[626] In addition, Clean Grid Alliance disagrees with MISO's arguments that the ERAS process will not take headroom from

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[621] *Id.* at 34.

[622] *Id.* (citing PJM RRI Order, 190 FERC ¶ 61,084 at P 245).

[623] MISO Answer at 30.

[624] Clean Grid Alliance Docket No. ER25-1674 Answer at 24-25.

[625] *Id.* at 16 (citing MISO Docket No. ER25-1674 Answer at 34; *Sw. Power Pool, Inc*., 147 FERC ¶ 61,201 at P 124).

[626] Clean Grid Alliance First Answer at 8-9.

DPP interconnection requests.[627] Clean Grid Alliance argues that MISO has not explained how the implementation of ERAS will not result in the same transmission capacity being allocated twice in concurrent DPP (i.e., DPP 2023 cycle) and ERAS studies, and then not result in interconnection requests in the next DPP cycle (i.e., DPP 2025 cycle) having to address any overallocations as pre-existing conditions. Clean Grid Alliance argues that if ERAS interconnection customers are interconnecting to, or depend on, the same transmission lines as DPP interconnection customers, then, given ERAS interconnection customers' priority to that transmission headroom, the DPP interconnection customers will be harmed.[628] Clean Grid Alliance argues that such a scenario is likely because MISO will not model DPP interconnection requests, even late-stage DPP Phase III interconnection requests, in ERAS interconnection studies.[629] In addition, Clean Grid Alliance claims that the ERAS process may harm DPP interconnection requests because serial restudies will absorb MISO staff time, given that restudies are necessary when an interconnection request withdraws, regardless of network upgrades remaining, due to the potential for counterflows.[630] In addition, Clean Grid Alliance raises concerns that MISO's proposal does not require ERAS interconnection customers to provide 100% of network upgrade costs as an initial payment, arguing that MISO may have to initiate legal action to collect funds from an ERAS interconnection customer with an EGIA that withdraws absent such protection.[631]

254. Clean Energy Associations argue that MISO fails to refute arguments that the ERAS study process will harm DPP interconnection customers stemming from: (1) uncertainty regarding the dispatch model that would be used for ERAS studies; (2) MISO's proposal to not include late-stage DPP interconnection requests in ERAS studies; and (3) use of the annual MTEP process to resolve over-allocation of transmission headroom across ERAS and DPP processes.[632] Clean Energy Associations argue that MISO's proposal will systematically advantage ERAS interconnection

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[627] *Id.* at 17.

[628] Clean Grid Alliance Docket No. ER25-1674 Answer at 18.

[629] Clean Grid Alliance First Answer at 8 (citing Clean Grid Alliance Protest at 21); Clean Grid Alliance Docket No. ER25-1674 Answer at 18. Clean Grid Alliance argues that MISO's submissions in prior filings before the Commission have noted that interconnection requests in DPP Phase III have a 90% success rate. *Id.*

[630] Clean Grid Alliance Docket No. ER25-1674 Answer at 19.

[631] *Id.* at 26.

[632] Clean Grid Alliance First Answer at 8 (citing Clean Grid Alliance Protest at 21); Clean Grid Alliance Docket No. ER25-1674 Answer at 10.

requests and lead to unresolved constraints, which will fall to subsequent DPP interconnection requests to address if the MTEP does not capture them. Clean Grid Alliance further asserts that LSEs have not committed to paying the cost for additional transmission capacity that MISO proposes to shift to MTEP.[633]

255. Clean Grid Alliance argues that MISO's admission, that ERAS interconnection requests "could be included in the ERAS process but ultimately not be approved in the state regulatory process and thus may not be completed at that point in time," conflicts with MISO's assertions that restudies in the ERAS process will not be an issue.[634]

256. MISO IPPs state that MISO did not respond to MISO IPPs' arguments that different study assumptions for ERAS and DPP interconnection requests will cause MISO to underestimate network upgrades for ERAS interconnection requests and shift the costs of those network upgrades to other entities.[635]

257. Clean Grid Alliance argues that MISO fails to address the Revised ERAS Proposal's harm to the DPP by allowing queue jumping and introducing reliability gaps caused by transmission capacity overallocation. Clean Grid Alliance avers that the Revised ERAS Proposal will only mitigate reliability impacts within the local balancing area where an ERAS interconnection request is located, while the DPP mitigates reliability impacts across the entire MISO footprint. Clean Grid Alliance contends that the Revised ERAS Proposal's approach is discriminatory. Clean Grid Alliance asserts that these harms are unnecessary because MISO already has the provisional GIA process through which interconnection customers can pursue an expedited interconnection and GIA.[636]

258. PIOs argue that MISO's answer does not address PIOs' concern that ERAS interconnection requests will receive more favorable study assumptions, which will likely enable ERAS interconnection requests to pay less for interconnection service than similarly situated DPP interconnection requests. PIOs contend that MISO's reliance on the fact that ERAS will incorporate only approved generating facilities, while the DPP includes all prior queued interconnection requests, is a key characteristic that is creating

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[633] Clean Grid Alliance First Answer at 9 (citing Clean Grid Alliance Protest at 22).

[634] Clean Grid Alliance Docket No. ER25-1674 Answer at 13-14 (citing MISO Docket No. ER25-1674 Answer at 16).

[635] MISO IPPs Answer at 13.

[636] Clean Grid Alliance Second Answer at 3.

the undue preference for ERAS interconnection requests.[637] PIOs aver that a process that subjects interconnection requests to two different baseline study assumptions will not eliminate inherent risks present when multiple interconnection requests rely on the same transmission infrastructure.[638]

c. Commission Determination

259. We find that MISO's proposal to evaluate ERAS interconnection requests in a separate, serial study process is just and reasonable and not unduly discriminatory or preferential and accomplishes the purposes of Order Nos. 2003 and 2023. Further, we find that MISO's Revised ERAS Proposal will not harm DPP interconnection customers and that the cap on the number of ERAS interconnection requests that may be studied provides a further guardrail to ensure ERAS is a limited process.

260. MISO seeks variations from the *pro forma* LGIP and *pro forma* LGIA under the independent entity variation standard, which provides that the proposed variations must be just, reasonable, not unduly discriminatory or preferential, and accomplish the purposes of Order Nos. 2003 and 2023.[639] MISO proposes to study ERAS interconnection requests using its existing NRIS modeling standards and the most recent MTEP base case that includes all generating facilities with executed GIAs. While protesters argue that limiting ERAS to 10 serial studies per quarterly study period does not alleviate the concern that the proposed serial study process is inconsistent with the requirements of Order No. 2023, we find that MISO's proposed approach is just and reasonable and accomplishes the purposes of Order Nos. 2003 and 2023. MISO's proposal to use a serial study process here does not present concerns related to queue withdrawals and restudies traditionally raised by serial cluster processes[640] because, as discussed above, interconnection projects in the ERAS process are less likely to be speculative and withdraw due to the enhanced commercial readiness requirements. MISO represents that there will not be any DPP or ERAS restudies associated with any ERAS projects that do withdraw.[641] Further, withdrawing ERAS interconnection customers are also responsible for any network upgrade costs assigned to them in an EGIA, which would mitigate risks regarding any potential cost impacts to lower-queued

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[637] PIOs Answer at 8-9.

[638] *Id.* at 9.

[639] *See* Transmittal at 23.

[640] Order No. 2023, 184 FERC ¶ 61,054 at P 47.

[641] MISO Docket No. ER25-1674 Supplemental Answer at 5.

interconnection customers.[642] Moreover, MISO's proposal to study ERAS interconnection requests using its existing NRIS modeling standards and the most recent MTEP base case while including all generating facilities with executed GIAs is just and reasonable because it will allow MISO to expedite the ERAS studies through a serial process that excludes DPP interconnection requests that are more likely to withdraw, e.g., those DPP interconnection requests that have not executed GIAs, because including such resources would create uncertainty in the ERAS study process.

261. We find protesters' claims that the implementation of ERAS will delay MISO's processing of the DPP to be speculative. As MISO explains, it will use the ERAS non-refundable application fee to support the necessary staffing and resources to allow MISO to process both the DPP and ERAS studies without negative impacts to the DPP queue.[643] We also note MISO's stated commitment to ensure proper staffing and resource allocation to avoid any delays to DPP study processing.[644]

262. Further, protesters argue that interconnection customers in future DPP cycles may be subject to higher network upgrade costs or curtailments under a potential scenario where the MTEP process does not identify network upgrades sufficient to resolve issues created by parallel DPP and ERAS studies. We find protesters' argument that MTEP might not address needed reliability upgrades to be speculative, and so we disagree with protesters that the potential for such an outcome renders MISO's proposal unjust and unreasonable. The Commission has previously found that interconnection customers have no legal rights to a given system topology or to whether upgrades may be required.[645] Further, given the way MISO's interconnection queue has been designed to encourage orderly withdrawals, lower-queued interconnection customers are frequently faced with changing network upgrade costs. Moreover, MISO explains that its proposed ERAS study will identify network upgrades and other facilities necessary for the interconnection of ERAS interconnection customers, and we therefore disagree that ERAS projects will

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[642] MISO, Proposed Tariff, attach. X (GIP) (171.0.0), § 3.9.6.3.

[643] MISO Answer at 141; MISO Docket No. ER25-1674 Answer at 47.

[644] MISO Docket No. ER25-1674 Answer at 47. Specifically, MISO states that the non-refundable $100,000 D1 application fee will allow MISO "to hire additional staff, as needed, to ensure that adoption of the ERAS process does not create harmful effects to the DPP interconnection process" and that it "is committed to making other resource or staffing changes to ensure that this remains true throughout the ERAS process." *Id.*

[645] PJM RRI Order, 190 FERC ¶ 61,084 at P 192.

either be inappropriately assigned network upgrade costs or not assigned network upgrade costs at all.

263. We do not find persuasive protesters' arguments that interconnection customers currently in the DPP queue will be harmed as a result of ERAS and will be subject to higher network upgrade costs due to the ERAS proposal. As MISO explains, DPP studies use the most recent MTEP model at the time that MISO commences the DPP study cycle as the base case, and that model will not be updated to include ERAS interconnection requests. Furthermore, as Texas Commission explains, the Revised ERAS Proposal protects interconnection customers currently in the DPP queue by preventing late-stage transfers, which could lead to unplanned restudies, and by requiring interconnection requests that transfer to ERAS to pay withdrawal penalties.[646] Therefore, interconnection customers currently in the DPP process will not see higher assigned network upgrade costs because their interconnection requests will continue to be studied without accounting for ERAS interconnection requests. In addition, we note that interconnection customers that submit interconnection requests into future DPP cycles will have notice of the existence of the ERAS process prior to submitting their interconnection requests and could factor the ERAS process into their commercial decisions. Furthermore, we note that DPP interconnection requests that have not reached Decision Point II in the 2022, 2023, and later cycles are eligible to transfer to the ERAS process, if they meet the eligibility requirements.[647]

264. In response to protesters' arguments that MISO's proposal will result in cost allocation inconsistent with cost causation, and that there is the potential for needed network upgrades to be identified in the MTEP process because ERAS interconnection requests may not be assigned their full "but for" costs, we find MISO's proposal to address through its existing processes any deliverability issues identified as a result of differences between the models used in the ERAS and DPP studies to be just and reasonable. As MISO explains, its current Tariff allocates to load the costs of network upgrades identified through its MTEP process, as needed, to maintain resource deliverability. Therefore, MISO's proposal is consistent with its existing, Commission-approved process for addressing deliverability issues identified outside of its process for studying interconnection requests.[648]

265. Protesters contend that the ERAS process is not a "one time" process because it includes multiple, quarterly study periods over several years. We do not find this concern

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[646] Texas Commission Comments at 11.

[647] Transmittal at 22.

[648] MISO Answer at Tab B, MISO Transmittal, Docket No. ER25-1674, at 30 (filed Apr. 21, 2025); Witmeier Docket No. ER25-1674 Rebuttal Testimony at 38-39.

persuasive. The Revised ERAS Proposal is timebound and will sunset at the earlier of August 31, 2027 or when MISO has studied 68 ERAS interconnection requests. We disagree with the arguments that the Revised ERAS Proposal must be a one-time cluster study, such as PJM's RRI proposal, to be just and reasonable. The Commission's acceptance of PJM's RRI does not preclude the Commission from accepting a different RTO or ISO proposal, such as MISO's proposal, which is not only tailored to address the specific needs of the MISO region but also considers the distinct characteristics of the MISO region.[649]

5. Affected Systems

a. MISO's Filing

266. MISO explains that, regarding affected system studies, neighboring transmission providers will have the right to evaluate the impact of ERAS interconnection requests on their transmission systems, just as with DPP interconnection requests.[650] MISO further explains that any ERAS interconnection request that meets the Joint Targeted Interconnection Queue (JTIQ) criteria will be subject to JTIQ study procedures.[651] MISO notes that the Revised ERAS Proposal was designed with the expectation that MISO would use existing affected system study processes and that it is actively working with multiple seams partners to develop additional seams procedures to incorporate the ERAS process.[652]

267. MISO proposes that ERAS interconnection requests will adhere to the same affected system screening criteria as applicable to DPP interconnection requests, with the following exceptions:

a. The transmission provider will submit all necessary information for an affected system to study an ERAS interconnection request no later than 10 calendar days prior to the applicable ERAS study kickoff;

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[649] *See* Order No. 2003, 104 FERC ¶ 61,103 at P 826 (stating that RTOs/ISOs "shall have greater flexibility to customize [their] interconnection procedures and agreement to fit regional needs").

[650] Transmittal at 38.

[651] *Id.* at 38, 48, 51, 55, 59-60; MISO, Proposed Tariff, attach. X (GIP) (175.0.0), §§ 1, 3.9.5, 7.3.1.4, 7.3.2.3.1.

[652] Witmeier Testimony at 64.

b. The transmission provider will provide any affected system analysis received from the affected system to the ERAS interconnection customer promptly upon receipt;

c. If affected system study results and cost information are not available at the time an EGIA is tendered, then such EGIA will include an obligation to execute any agreements for the study, construction, or funding of network upgrades identified by the affected system within 15 calendar days after such an agreement is tendered to the interconnection customer;

d. The transmission provider will submit ERAS interconnection request information to the affected system operator individually and request that the affected system operator study the ERAS interconnection request serially; and

e. When MISO and the affected system operator use a specified point in the DPP, such as a decision point or a DPP phase kickoff date, to establish the queue priority date of a MISO interconnection request, MISO will assert a queue priority date for ERAS interconnection requests as of the date that MISO commences the ERAS system impact study unless the controlling agreement between MISO and the affected system operator provides for an alternative queue priority date. Additionally, for interconnection requests with an earlier queue priority date, "in accordance with this section 9.4.3 (a) will have a higher relative queue priority than those with a later queue priority date."[653]

268. MISO states that it will provide affected system study results in the final ERAS study report, in the draft EGIA, or when they are received from the affected system operator, if they are not available at the time of the final ERAS study results and/or at the time of EGIA execution.[654] MISO explains that, in the event that an interconnection customer withdraws its ERAS interconnection request and terminates its EGIA after execution of the EGIA or after requesting that the EGIA be filed unexecuted, the interconnection customer will be liable for the network upgrades arising from the affected system study process.[655]

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[653] MISO, Proposed Tariff, attach. X (GIP) (175.0.0), § 3.5.2.

[654] Transmittal at 38; MISO, Proposed Tariff, attach. X (GIP) (175.0.0), §§ 3.9.3, 3.9.5; *see also* Witmeier Testimony at 65.

[655] Witmeier Testimony at 66.

269. MISO contends that this process will ensure a timely affected system study appropriate for the ERAS process while still providing necessary flexibility for MISO and individual seams partners.[656]

b. Responsive Pleadings

i. Protests

270. MISO IPPs argue that the Revised ERAS Proposal fails to adequately address how MISO will manage affected system studies for ERAS interconnection requests and how such affected system studies may impact DPP interconnection requests.[657] MISO IPPs argue that affected system studies are time-consuming and can cause substantial delays, yet MISO largely ignores the issue of affected system studies, merely stating that MISO will include affected system study results in the ERAS study if available, and if not available, MISO will provide them separately when received from the applicable affected system. MISO IPPs argue that this leaves questions, including whether affected system studies will cause delays in processing ERAS interconnection requests and/or DPP interconnection requests.[658]

271. Invenergy argues that ERAS does not align with Order No. 2023's requirement that affected system studies be completed in clusters in order of queue priority based on when the affected system study agreement was executed. Invenergy states that while MISO has filed provisions for its JTIQ with SPP, it does not explain how the serial nature of ERAS would interface with the affected system cluster study process.[659]

272. Clean Grid Alliance argues that information regarding the affected system process remains unclear and lacks critical details on MISO's coordination with its seams partners.[660] Clean Grid Alliance asserts that MISO has not explained how neighboring transmission systems would be able to individually process 10 ERAS interconnection requests quarterly through 2027, as well as how those studies would align with the affected system operator's study of DPP interconnection requests and its own queue.

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[656] Transmittal at 51.

[657] MISO IPPs Docket No. ER25-1674 Protest at 25 (citing MISO, Docket No. ER25-1674, Proposed Tariff, attach. X (GIP) (169.0.0), § 3.9.3).

[658] MISO IPPs Docket No. ER25-1674 Protest at 25 (citing MISO, Docket No. ER25-1674, Proposed Tariff, attach. X (GIP) (169.0.0), § 3.9.3).

[659] Invenergy Protest at 18.

[660] Clean Grid Alliance Protest at 27.

Similarly, MISO IPPs argue that it is unclear whether affected system studies will cause delays in processing DPP interconnection requests.[661] Clean Grid Alliance argues that affected system coordination has been a significant source of queue processing delays, and such delays are misaligned with meeting MISO's claimed near-term resource adequacy and reliability needs.[662]

273. Clean Energy Associations contend that ERAS interconnection customers may be put in the position to sign an EGIA before receiving information about affected system networks upgrades and argues that this conflicts with the requirement adopted in Order No. 2023 for a host transmission provider to delay the deadline for an interconnection customer to file its LGIA, at an interconnection customer's request, if the affected system study results have not been received.[663]

274. Clean Energy Associations argue that the risk of limited information on affected system study results might deter independent power producers' interconnection requests that are well suited to meet near-term resource adequacy needs from applying for the ERAS process, while posing relatively little risk to LSE-owned or affiliated generation that can pass along unexpected affected system network upgrade costs to consumers.[664]

ii. Answers

(a) MISO Answer

275. In response to concerns regarding the lack of detail on the affected system study process for ERAS interconnection requests, MISO explains that ERAS interconnection requests will be subject to the same affected system process as DPP interconnection requests, including the same criteria used by MISO's seams partners.[665]

276. Further, in response to protesters' arguments that LSEs can pass along affected system costs to consumers without bearing the same risk as independent power producers, MISO states that differences in risk profiles already existed between LSEs and

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[661] MISO IPPs Docket No. ER25-1674 Protest at 25 (citing MISO, Docket No. ER25-1674, Proposed Tariff, attach. X (GIP) (169.0.0), § 3.9.3).

[662] Clean Grid Alliance Protest at 28.

[663] Clean Energy Associations Docket No. ER25-1674 Protest at 24-25.

[664] Clean Energy Associations Protest at 24-25 (citing Clean Energy Associations Docket No. ER25-1674 Protest at 25, 48-51).

[665] MISO Docket No. ER25-1674 Answer at 41.

independent power producers prior to the Revised ERAS Proposal and are not a result of that proposal.[666]

(b) Additional Answers

277. Clean Grid Alliance argues that MISO fails to explain how the Revised ERAS Proposal would lead to an expedited process to bring new generation online if ERAS and DPP interconnection requests are subject to the same affected system processes.[667] Clean Grid Alliance also argues that MISO does not provide sufficient information about how it will coordinate affected system studies with all seams partners and that the lack of information does not satisfy MISO's burden under FPA section 205.[668] Further, Clean Grid Alliance argues that MISO's statement that it will merely request that an affected system operator study ERAS interconnection requests on a serial basis is contrary to the Commission's reforms in Order No. 2023 to firm-up the affected system study process and draw clearly defined parameters.[669]

c. Commission Determination

278. We find that MISO's proposed process to notify affected system operators of potential impacts to their transmission systems from ERAS interconnection requests in a serial fashion, as well as MISO's requirements regarding affected system network upgrade obligations on ERAS interconnection customers, to be just and reasonable and not unduly discriminatory or preferential and accomplishes the purposes of Order Nos. 2003 and 2023. MISO's proposal will ensure that ERAS interconnection requests are evaluated for impacts on affected systems like other interconnection requests, consistent with Commission precedent.[670] As MISO states, the ERAS interconnection requests are subject to the same affected system study process as DPP interconnection requests, including the same criteria currently used by MISO's seams partners, albeit MISO will notify those seams partners of potential impacts in a serial manner. MISO's proposal to use a serial study process here does not present concerns related to queue

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[666] *Id.* at 29-30.

[667] Clean Grid Alliance Docket No. ER25-1674 Answer at 10.

[668] *Id.* at 20-21.

[669] *Id.* at 22 (citing MISO Answer at 44; Order No. 2023, 184 FERC ¶ 61,054 at P 1111).

[670] Order No. 2003, 104 FERC ¶ 61,103 at P 118.

withdrawals and restudies traditionally raised by serial study processes[671] because, as discussed above, interconnection projects in the ERAS process are less likely to be speculative and withdraw due to the enhanced commercial readiness requirements.

279. We disagree with protesters that requiring ERAS interconnection customers to execute an EGIA, or request that it be filed unexecuted, prior to receiving affected system study results is unjust and unreasonable. The proposed ERAS eligibility criteria and requirements are intended to ensure that non-speculative, "shovel ready" projects enter the ERAS process and move expeditiously to EGIA execution. To the extent that an interconnection customer is not willing to execute an EGIA without affected system study results, the interconnection customer may withdraw from the ERAS process.[672] Additionally, as the Commission noted in Order No. 2023-A, there is no requirement for affected system network upgrade costs to be known at the time of LGIA execution, which in ERAS would be at the time of EGIA execution or requesting that it be filed unexecuted.[673]

280. Finally, we disagree with the concerns raised by certain protesters that MISO's Revised ERAS Proposal provides vague information regarding affected system studies. We find that MISO's proposed Tariff language provides sufficient detail regarding the process in which MISO will notify affected system operators of potential impacts from ERAS interconnection requests, as well as how MISO will relay the results of affected system analysis to ERAS interconnection customers.

6. Miscellaneous

a. MISO's Filing

281. MISO states that following the Commission's rejection of the Initial ERAS Proposal, it re-engaged with stakeholders to develop the Revised ERAS Proposal.[674] MISO states that it presented the Revised ERAS Proposal at the Planning Action Committee meeting on May 28, 2025 and received feedback from stakeholders through

[671] Order No. 2023, 184 FERC ¶ 61,054 at P 47.

[672] We note that withdrawing ERAS interconnection requests that withdraw prior to executing an EGIA will forfeit their non-refundable $100,000 D1 payment. *See* MISO, Proposed Tariff, attach. X (GIP) (175.0.0) § 3.9.2.

[673] Order No. 2023-A, 186 FERC ¶ 61,199 at P 494.

[674] Transmittal at 19.

its informal feedback tool.[675] MISO also asserts that it held "dozens" of calls with stakeholders.[676]

a. Responsive Pleadings

i. Comments in Support

282. Big Rivers Electric asserts that the Revised ERAS Proposal underwent extensive review and discussion through MISO's stakeholder process, and MISO adopted many stakeholder recommendations to enhance the proposal's effectiveness. Big Rivers Electric further states that MISO has provided extensive opportunity for all interested parties to participate in stakeholder processes and that the Revised ERAS Proposal reflects substantial stakeholder input gathered over the past several months.[677]

283. CenterPoint states that MISO's Revised ERAS Proposal enjoys widespread support from the State of Indiana, as expressed by a concurrent resolution passed by the Indiana House of Representatives and Senate urging reform processes to expedite the approval of electric transmission and generation projects and a letter from Indiana Governor Mike Braun expressing his strong support for MISO's efforts to address pressing resource adequacy challenges.[678] Furthermore, CenterPoint notes that Indiana Energy Association has expressed its support for the Revised ERAS Proposal, as it will help account for the growing complexity of the energy landscape and ensure that sufficient resources are available to meet immediate and future demand.

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[675] *Id.* (citing MISO, *Expedited Resource Addition Study (ERAS) Next Steps* (May 28, 2025), https://cdn.misoenergy.org/20250528%20PAC%20Item%2008%20Expedited%20Resource%20Addition%20St udy%20(ERAS)%20Next%20Steps%20(PAC-2023-1)699836.pdf.; Informal Feedback (2025), MISO, https://www.misoenergy.org/engage/stakeholder-feedback/2025/informalfeedback-2025/).

[676] Witmeier Testimony at 23.

[677] Big Rivers Electric Comments at 5-6.

[678] CenterPoint Comments at 5-6.

ii. Protests

284. Several protesters raise concerns over the stakeholder process that preceded the Revised ERAS Proposal.[679] Clean Grid Alliance states that MISO never informed stakeholders of its plan to request a shortened comment period.[680] PIOs contend that the silence from some states likely reflects the inadequate time to respond under the shortened comment period rather than their support.[681] Illinois Commission and PIOs assert that pre-filing stakeholder engagement on the Revised ERAS Proposal was limited due to MISO's quick refiling of its ERAS proposal, and there was no formal stakeholder feedback requested by MISO prior to filing the revisions.[682] PIOs and Clean Grid Alliance assert that MISO did not publicly share its proposed Tariff language prior to filing with the Commission.[683] PIOs state that they have had conversations with Minnesota State Commissioners who have expressed concern over the Revised ERAS Proposal.[684]

285. PIOs argue that this lack of stakeholder engagement renders the Revised ERAS Proposal legally vulnerable. According to PIOs, the record is insufficient for the Commission to make a reasoned decision, and MISO violated Order No. 719,[685] by which an RTO/ISO must be responsive to the needs of its customers and stakeholders.[686] PIOs allege that because MISO bypassed its normal stakeholder process and rushed the revision of the ERAS proposal, MISO failed to "make well-informed decisions that

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[679] Clean Grid Alliance Protest at 3-4; Illinois Commission Comments at 3; PIOs Protest at 1, 32-37.

[680] Clean Grid Alliance Protest at 3-4.

[681] PIOs Protest at 40.

[682] *Id.* at 34; Illinois Commission Comments at 3.

[683] Clean Grid Alliance Protest at 3; PIOs Protest at 35.

[684] PIOs Protest at 40-41 (citing Minnesota Commission, *MISO Quarterly Update Meeting* (June 6, 2025)). PIOs include quotes from Minnesota State Commissioners Hwikwon Ham and Joseph Sullivan, who voiced concerns over MISO's Revised ERAS Proposal process at the Minnesota Commission meeting on June 6, 2025.

[685] *Wholesale Competition in Regions with Organized Elec. Mkts*, Order No. 719, 125 FERC ¶ 61,071 (2008), *order on reh'g*, Order No. 719-A, 128 FERC ¶ 61,059, *order on reh'g*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

[686] PIOs Protest at 37-38.

reflect the full range of competing interests that may be affected," and also failed to meet the ongoing responsiveness requirements of Order No. 719.[687] PIOs contend that MISO has also arguably failed to meet the remaining criteria outlined in Order No. 719 to ensure a balancing of diverse interests and representation of minority interests because the Revised ERAS Proposal has not gone before the MISO Board of Directors.[688]

286. Finally, PIOs assert that MISO's rushed process to submit the Revised ERAS Proposal has resulted in numerous errors in its filing. PIOs state that, for example, the proposed Tariff language includes references in the EGIA to the three-year grace period provided for under GIP section 4.4.4 but that this conflicts with the language in proposed GIP section 3.9.8, which states that no changes to the commercial operation date are permitted once an interconnection request enters ERAS.[689]

iii. Answers

(a) MISO Answer

287. MISO states that it worked to quickly file the Revised ERAS Proposal to address the failures identified by the Commission in the May 2025 Order and to create a fully workable process that could be implemented this year.[690] MISO disagrees with protesters that the stakeholder process was rushed.[691] MISO asserts that it made targeted changes to its Initial ERAS Proposal, which was crafted with extensive stakeholder input, and that the changes were not created in a vacuum. MISO asserts that the Revised ERAS Proposal applied lessons learned from the original stakeholder process, considered the Commission's findings, and engaged with stakeholders on an individual basis to receive feedback on the proposed changes. Thus, MISO states that the Revised ERAS Proposal is the result of MISO responding to input from a variety of parties, stakeholder protests to the Initial ERAS Proposal, and feedback from individual stakeholders on the Revised ERAS Proposal. MISO asserts that it was necessary to quickly file the Revised ERAS

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[687] *Id.* at 37 (citing Order No. 719, 125 FERC ¶ 61,071 at PP 506-509).

[688] *Id*.

[689] *Id.* at 38 (citing MISO, Proposed Tariff, attach. X (GIP) (175.0.0), §§ 4.4.4, 3.9.8; *id.* app. 6 (GIA) (106.0.0), art. 2.3.1.

[690] MISO Answer at 11.

[691] *Id.* (citing Clean Energy Associations Protest at 5-6; COMPP Protest at 6-7; Illinois Commission Comments at 2-3; Michigan Commission Protest at 2; PIOs Protest at 3).

Proposal to enable MISO to begin ERAS this year and to address its short-term resource adequacy and reliability needs.[692]

288. MISO states that it acknowledges the diverse interests of the stakeholder community but argues that developing a proposal that satisfies every interest of each stakeholder is not possible, nor should that be the benchmark.[693]

(b) Additional Answers

289. PIOs contend that MISO has not explained how holding a full stakeholder process to implement their suggestions would hinder the intended benefits of the Revised ERAS Proposal.[694] PIOs point out that OMS has not provided input on the Revised ERAS Proposal and that the Commission should not assume parties that supported the Initial ERAS Proposal also support the instant filing. PIOs argue that MISO's statements that it reached out to certain stakeholders are indicative of a secretive and exclusive process that falls short of the standards for stakeholder engagement outlined in Order No. 719. PIOs further argue that it is concerning that many of the revisions following the May 2025 Order appear to be at the request of individual stakeholders.[695]

b. Commission Determination

290. We disagree with protesters' contention that MISO's stakeholder process for the Revised ERAS Proposal is a basis to reject the filing. We find that MISO's stakeholder process for the Revised ERAS Proposal, though it entailed a more targeted approach than the one taken for the Initial ERAS Proposal, was sufficiently responsive to stakeholder feedback within the context of the revisions that MISO sought to make in its Revised ERAS Proposal, and consistent with MISO's existing governance procedures and stakeholder processes that the Commission has already approved as compliant with Order No. 719.[696] MISO states that the Revised ERAS Proposal focused on limited modifications to the Initial ERAS Proposal in order to be responsive to the May 2025 Order, and as such, MISO engaged with stakeholders on a targeted basis to refine an

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[692] *Id.* at 11-12.

[693] *Id.* at 30.

[694] PIOs Answer at 13 (citing Witmeier Docket No. ER25-1674 Rebuttal Testimony at 5).

[695] *Id.*

[696] *See Midwest Indep. Transmission Sys. Operator, Inc.*, 133 FERC ¶ 61,068, at P 44 (2010).

existing prior proposal, as compared to the more extensive stakeholder process for the Initial ERAS Proposal, which included discussions, presentations, and numerous opportunities for stakeholder input.[697] According to MISO, following the May 2025 Order, MISO re-engaged with its stakeholders at the May 28, 2025 Planning Action Committee meeting, and thereafter, MISO received feedback from stakeholders through its informal feedback tool.[698] In addition, MISO states that the Revised ERAS Proposal incorporates feedback that was received for the Initial ERAS Proposal.[699] Thus, MISO asserts that the Revised ERAS Proposal responds to the Commission's guidance, stakeholder protests to the Initial ERAS Proposal, input from a variety of parties, and feedback from individual stakeholders on the Revised ERAS Proposal.[700]

The Commission orders:

(A) MISO's proposed Tariff revisions are hereby accepted, subject to condition, effective August 6, 2025, as requested, as discussed in the body of this order.

(B) MISO is hereby directed to submit a further compliance filing within 30 days of the date of this order, as discussed in the body of this order.

By the Commission. Commissioner Chang is concurring with a separate statement attached.

(S E A L)

Debbie-Anne A. Reese,
Secretary.

[697] *See* Transmittal at 18.

[698] *Id.* at 19.

[699] Witmeier Docket No. ER25-1674 Rebuttal Testimony at 5.

[700] MISO Answer at 11.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Midcontinent Independent System Operator, Inc. Docket No. ER25-2454-000

(Issued July 21, 2025)

CHANG, Commissioner, *concurring*:

1. I concur in today's order accepting Midcontinent Independent System Operator, Inc's (MISO) Expedited Resource Addition Study (ERAS) proposal as just and reasonable, and not unduly discriminatory or preferential, because it is sufficiently tailored to reflect the specific needs that are rapidly arising in the MISO region. I write separately, given my prior dissent on PJM Interconnection, L.L.C.'s (PJM) Reliability Resource Initiative (RRI) proposal.[1]

2. Regulators and the utilities we oversee are responsible for ensuring that customers' needs are reliably and affordably met. For more than two decades, the Commission and the industry have relied on non-discriminatory interconnection procedures to facilitate access for new generation of all types. It is no secret that queues around the country, and particularly in the regional transmission organizations, are strained, which has significantly delayed the interconnection of new resources needed to serve new and existing loads. In response, the Commission, grid operators, and utilities are searching for solutions to process backlogged queues and expedite the interconnection of new resources.[2]

3. As a general matter, when faced with the challenge of the existing queue backlogs, I disfavor temporary solutions that do not help resolve the underlying problem. One-off short-term fixes can create additional problems and at times beget further one-off fixes. Developing these types of temporary proposals can detract from our collective efforts to address the more fundamental underlying issues. Furthermore, interconnection queue proposals that grant priority access to the system are, at minimum, in tension with

[1] *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084 (2025) (Chang, Comm'r, dissenting).

[2] *See, e.g.*, *Improvements to Generator Interconnection Procs. & Agreements*, Order No. 2023, 184 FERC ¶ 61,054, *order on reh'g*, 185 FERC ¶ 61,063 (2023), *order on reh'g*, Order No. 2023-A, 186 FERC ¶ 61,199, *errata notice*, 188 FERC ¶ 61,134 (2024); *Midcontinent Indep. Sys. Operator, Inc.*, 190 FERC ¶ 61,057 (2025) (approving MISO's generator interconnection queue cap).

competition and open access to the transmission system, which I believe have served customers well and should not be lightly discarded. Any deviations from the traditional Commission policy or existing, generally applicable queue procedures have a very high bar to clear.

4. Nonetheless, to meet the challenge of resource adequacy, as I explained in my dissent on PJM's RRI proposal, I am open to considering region-specific deviations from generally applicable interconnection queue procedures, given the Commission's paramount obligation to ensure that system operators can reliably serve their loads. Consistent with my analysis there, I assess here (1) whether MISO has demonstrated a sufficient reliability need to justify its proposed deviation, and (2) whether its proposed solution to that need is sufficiently tailored to address it. As discussed below, I find that MISO has satisfied both showings and I therefore approve its filing.

5. In the MISO region, most of the states and load serving entities (LSEs) have full responsibility over their own resource adequacy. These entities must ensure that sufficient supply and demand-side resources will be able to meet the growing load, and they do so through resource planning processes that state regulators oversee. Those resource planning processes are used to determine the utilities' investments in and contracts with new resources. MISO's proposal, which gives states a voice in which projects are selected for ERAS, codifies that selection decision into MISO's tariff for a limited set of projects that can most readily meet the specific needs identified by the states. MISO's ERAS process essentially moves the timing of when a proposed resource is selected by a state or an LSE from the after the interconnection process to before it, while maintaining the responsibility of the states and LSEs to ensure their footprints are resource adequate.

6. To facilitate such role for the state and the LSEs, each ERAS interconnection request must be accompanied by a written verification from a state entity that there is a need for the resource to interconnect to the MISO system. Along with that verification, the resource must have a power purchase agreement or other agreement to ensure that the resource has a commercial off-taker that plans to use the generation as soon as it is in commercial operation. The state and the LSE must identify a specific load addition or resource adequacy need that the planned resource will meet. These factors ensure that the ERAS projects are needed, supported by state entities, and sufficiently commercially viable to ensure the projects are actually constructed.

7. MISO has put in place significant requirements for the interconnection customers seeking to use the ERAS process. First, the proposal allows for an addition of only 68 projects to an expedited interconnection process. Of those 68, eight are reserved for restructured states, ten are reserved for independent power producers, and the remaining 50 are available to any type of interconnection customer, whether they are affiliated with the interconnecting transmission owner or not. While limiting the number of projects that

can participate is a minimum requirement to avoid creating a perpetual process under which certain resources can bypass the existing queue, it is not only the limited number of projects that makes MISO's ERAS proposal acceptable. Next, each project must demonstrate full site control and must provide several financial payments to enter the process. Both of these requirements will limit the projects that seek to enter the ERAS queue and will limit withdrawals from the ERAS process and other queue disruptions.

8. MISO's proposal requires that it study all of the ERAS requests by the earlier of the completion of all 68 studies or August 31, 2027. This ensures that this process does not linger past the time where MISO explains it needs the new generation the most and ensures that the ERAS process is truly a one-time exception to the traditional interconnection process as required by Orders No. 2003 and 2023. It is extremely important that this process is limited to a short term, one-time fix, and I appreciate MISO's revised requirements to ensure it completes the ERAS process by August 31, 2027.

9. MISO also explains that it will study no more than 10 projects per quarter, which will necessarily limit the staffing needed to process the ERAS studies. While MISO is implementing various computational solutions to improve the processing of interconnection requests, it is still constrained by the number of personnel that can work on the studies. By limiting to studying only 10 projects per quarter, MISO's ERAS proposal should help ensure that MISO's staff has enough bandwidth to continue the important work on processing the existing interconnection queue.[3]

10. Overall, I am persuaded that MISO's ERAS proposal is a just and reasonable solution to, in the short term, add resources that can address imminent demand growth and locational resource adequacy challenges. I truly hope this process is a successful bridge to the more durable and equitable implementation of MISO's latest interconnection reforms and the reforms required by Order No. 2023, which should provide better long-term outcomes under the Commission's traditional open access framework.

For these reasons, I respectfully concur.

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Judy W. Chang
Commissioner

[3] *Midcontinent Indep. Sys. Operator, Inc.*, 192 FERC ¶ 61,064, at P 110 (2025).

Document Content(s)

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-7

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

Filed September 5, 2025

Exhibit 92

Energy Emergency EO

Federal Register
Vol. 90, No. 18
Wednesday, January 29, 2025

Presidential Documents

Title 3—

The President

Executive Order 14156 of January 20, 2025

Declaring a National Energy Emergency

By the authority vested in me as President by the Constitution and the laws of the United States of America, including the National Emergencies Act (50 U.S.C. 1601 *et seq.*) (''NEA''), and section 301 of title 3, United States Code, it is hereby ordered:

Section 1. *Purpose.* The energy and critical minerals (''energy'') identification, leasing, development, production, transportation, refining, and generation capacity of the United States are all far too inadequate to meet our Nation's needs. We need a reliable, diversified, and affordable supply of energy to drive our Nation's manufacturing, transportation, agriculture, and defense industries, and to sustain the basics of modern life and military preparedness. Caused by the harmful and shortsighted policies of the previous administration, our Nation's inadequate energy supply and infrastructure causes and makes worse the high energy prices that devastate Americans, particularly those living on low- and fixed-incomes.

This active threat to the American people from high energy prices is exacerbated by our Nation's diminished capacity to insulate itself from hostile foreign actors. Energy security is an increasingly crucial theater of global competition. In an effort to harm the American people, hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets. An affordable and reliable domestic supply of energy is a fundamental requirement for the national and economic security of any nation.

The integrity and expansion of our Nation's energy infrastructure—from coast to coast—is an immediate and pressing priority for the protection of the United States' national and economic security. It is imperative that the Federal government puts the physical and economic wellbeing of the American people first.

Moreover, the United States has the potential to use its unrealized energy resources domestically, and to sell to international allies and partners a reliable, diversified, and affordable supply of energy. This would create jobs and economic prosperity for Americans forgotten in the present economy, improve the United States' trade balance, help our country compete with hostile foreign powers, strengthen relations with allies and partners, and support international peace and security. Accordingly, our Nation's dangerous energy situation inflicts unnecessary and perilous constraints on our foreign policy.

The policies of the previous administration have driven our Nation into a national emergency, where a precariously inadequate and intermittent energy supply, and an increasingly unreliable grid, require swift and decisive action. Without immediate remedy, this situation will dramatically deteriorate in the near future due to a high demand for energy and natural resources to power the next generation of technology. 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. Our Nation's current inadequate development of domestic energy resources leaves us vulnerable to hostile foreign actors and poses an imminent and growing threat to the United States' prosperity and national security.

These numerous problems are most pronounced in our Nation's Northeast and West Coast, where dangerous State and local policies jeopardize our Nation's core national defense and security needs, and devastate the prosperity of not only local residents but the entire United States population. The United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy. In light of these findings, I hereby declare a national emergency.

Sec. 2. *Emergency Approvals.* (a) The heads of executive departments and agencies (''agencies'') shall identify and exercise any lawful emergency authorities available to them, as well as all other lawful authorities they may possess, to facilitate the identification, leasing, siting, production, transportation, refining, and generation of domestic energy resources, including, but not limited to, on Federal lands. If an agency assesses that use of either Federal eminent domain authorities or authorities afforded under the Defense Production Act (Public Law 81–774, 50 U.S.C. 4501 *et seq.*) are necessary to achieve this objective, the agency shall submit recommendations for a course of action to the President, through the Assistant to the President for National Security Affairs.

(b) Consistent with 42 U.S.C. 7545(c)(4)(C)(ii)(III), the Administrator of the Environmental Protection Agency, after consultation with, and concurrence by, the Secretary of Energy, shall consider issuing emergency fuel waivers to allow the year-round sale of E15 gasoline to meet any projected temporary shortfalls in the supply of gasoline across the Nation.

Sec. 3. *Expediting the Delivery of Energy Infrastructure.* (a) To facilitate the Nation's energy supply, agencies shall identify and use all relevant lawful emergency and other authorities available to them to expedite the completion of all authorized and appropriated infrastructure, energy, environmental, and natural resources projects that are within the identified authority of each of the Secretaries to perform or to advance.

(b) To protect the collective national and economic security of the United States, agencies shall identify and use all lawful emergency or other authorities available to them to facilitate the supply, refining, and transportation of energy in and through the West Coast of the United States, Northeast of the United States, and Alaska.

(c) The Secretaries shall provide such reports regarding activities under this section as may be requested by the Assistant to the President for Economic Policy.

Sec. 4. *Emergency Regulations and Nationwide Permits Under the Clean Water Act (CWA) and Other Statutes Administered by the Army Corps of Engineers.* (a) Within 30 days from the date of this order, the heads of all agencies, as well as the Secretary of the Army, acting through the Assistant Secretary of the Army for Civil Works shall:

(i) identify planned or potential actions to facilitate the Nation's energy supply that may be subject to emergency treatment pursuant to the regulations and nationwide permits promulgated by the Corps, or jointly by the Corps and EPA, pursuant to section 404 of the Clean Water Act, 33 U.S.C. 1344, section 10 of the Rivers and Harbors Act of March 3, 1899, 33 U.S.C. 403, and section 103 of the Marine Protection Research and Sanctuaries Act of 1972, 33 U.S.C. 1413 (collectively, the ''emergency Army Corps permitting provisions''); and

(ii) shall provide a summary report, listing such actions, to the Director of the Office of Management and Budget (''OMB''); the Secretary of the Army, acting through the Assistant Secretary of the Army for Civil Works; the Assistant to the President for Economic Policy; and the Chairman of the Council on Environmental Quality (CEQ). Such report may be combined, as appropriate, with any other reports required by this order.

(b) Agencies are directed to use, to the fullest extent possible and consistent with applicable law, the emergency Army Corps permitting provisions to facilitate the Nation's energy supply.

(c) Within 30 days following the submission of the initial summary report described in subsection (a)(ii) of this section, each department and agency shall provide a status report to the OMB Director; the Secretary of the Army, acting through the Assistant Secretary of the Army for Civil Works; the Director of the National Economic Council; and the Chairman of the CEQ. Each such report shall list actions taken within subsection (a)(i) of this section, shall list the status of any previously reported planned or potential actions, and shall list any new planned or potential actions that fall within subsection (a)(i). Such status reports shall thereafter be provided to these officials at least every 30 days for the duration of the national emergency and may be combined, as appropriate, with any other reports required by this order.

(d) The Secretary of the Army, acting through the Assistant Secretary of the Army for Civil Works, shall be available to consult promptly with agencies and to take other prompt and appropriate action concerning the application of the emergency Army Corps permitting provisions. The Administrator of the EPA shall provide prompt cooperation to the Secretary of the Army and to agencies in connection with the discharge of the responsibilities described in this section.

Sec. 5. *Endangered Species Act (ESA) Emergency Consultation Regulations.* (a) No later than 30 days from the date of this order, the heads of all agencies tasked in this order shall:

(i) identify planned or potential actions to facilitate the Nation's energy supply that may be subject to the regulation on consultations in emergencies, 50 CFR 402.05, promulgated by the Secretary of the Interior and the Secretary of Commerce pursuant to the Endangered Species Act (''ESA''), 16 U.S.C. 1531 *et seq.;* and

(ii) provide a summary report, listing such actions, to the Secretary of the Interior, the Secretary of Commerce, the OMB Director, the Director of the National Economic Council, and the Chairman of CEQ. Such report may be combined, as appropriate, with any other reports required by this order.

(b) Agencies are directed to use, to the maximum extent permissible under applicable law, the ESA regulation on consultations in emergencies, to facilitate the Nation's energy supply.

(c) Within 30 days following the submission of the initial summary report described in subsection (a)(ii) of this section, the head of each agency shall provide a status report to the Secretary of the Interior, the Secretary of Commerce, the OMB Director, the Director of the National Economic Council, and the Chairman of CEQ. Each such report shall list actions taken within the categories described in subsection (a)(i) of this section, the status of any previously reported planned or potential actions, and any new planned or potential actions within these categories. Such status reports shall thereafter be provided to these officials at least every 30 days for the duration of the national emergency and may be combined, as appropriate, with any other reports required by this order. The OMB Director may grant discretionary exemptions from this reporting requirement.

(d) The Secretary of the Interior shall ensure that the Director of the Fish and Wildlife Service, or the Director's authorized representative, is available to consult promptly with agencies and to take other prompt and appropriate action concerning the application of the ESA's emergency regulations. The Secretary of Commerce shall ensure that the Assistant Administrator for Fisheries for the National Marine Fisheries Service, or the Assistant Administrator's authorized representative, is available for such consultation and to take such other action.

Sec. 6. *Convening the Endangered Species Act Committee.* (a) In acting as Chairman of the Endangered Species Act Committee, the Secretary of the Interior shall convene the Endangered Species Act Committee not less than quarterly, unless otherwise required by law, to review and consider any lawful applications submitted by an agency, the Governor of a State,

or any applicant for a permit or license who submits for exemption from obligations imposed by Section 7 of the ESA.

(b) To the extent practicable under the law, the Secretary of the Interior shall ensure a prompt and efficient review of all submissions described in subsection (a) of this section, to include identification of any legal deficiencies, in order to ensure an initial determination within 20 days of receipt and the ability to convene the Endangered Species Act Committee to resolve the submission within 140 days of such initial determination of eligibility.

(c) In the event that the committee has no pending applications for review, the committee or its designees shall nonetheless convene to identify obstacles to domestic energy infrastructure specifically deriving from implementation of the ESA or the Marine Mammal Protection Act, to include regulatory reform efforts, species listings, and other related matters with the aim of developing procedural, regulatory, and interagency improvements.

Sec. 7. *Coordinated Infrastructure Assistance.* (a) In collaboration with the Secretaries of Interior and Energy, the Secretary of Defense shall conduct an assessment of the Department of Defense's ability to acquire and transport the energy, electricity, or fuels needed to protect the homeland and to conduct operations abroad, and, within 60 days, shall submit this assessment to the Assistant to the President for National Security Affairs. This assessment shall identify specific vulnerabilities, including, but not limited to, potentially insufficient transportation and refining infrastructure across the Nation, with a focus on such vulnerabilities within the Northeast and West Coast regions of the United States. The assessment shall also identify and recommend the requisite authorities and resources to remedy such vulnerabilities, consistent with applicable law.

(b) In accordance with section 301 of the National Emergencies Act (50 U.S.C. 1631), the construction authority provided in section 2808 of title 10, United States Code, is invoked and made available, according to its terms, to the Secretary of the Army, acting through the Assistant Secretary of the Army for Civil Works, to address any vulnerabilities identified in the assessment mandated by subsection (a). Any such recommended actions shall be submitted to the President for review, through the Assistant to the President for National Security Affairs and the Assistant to the President for Economic Policy.

Sec. 8. *Definitions.* For purposes of this order, the following definitions shall apply:

(a) The term ''energy'' or ''energy resources'' means crude oil, natural gas, lease condensates, natural gas liquids, refined petroleum products, uranium, coal, biofuels, geothermal heat, the kinetic movement of flowing water, and critical minerals, as defined by 30 U.S.C. 1606 (a)(3).

(b) The term ''production'' means the extraction or creation of energy.

(c) The term ''transportation'' means the physical movement of energy, including through, but not limited to, pipelines.

(d) The term ''refining'' means the physical or chemical change of energy into a form that can be used by consumers or users, including, but not limited to, the creation of gasoline, diesel, ethanol, aviation fuel, or the beneficiation, enrichment, or purification of minerals.

(e) The term ''generation'' means the use of energy to produce electricity or thermal power and the transmission of electricity from its site of generation.

(f) The term ''energy supply'' means the production, transportation, refining, and generation of energy.

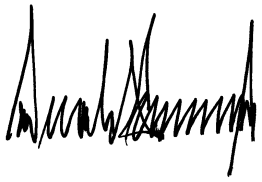
Sec. 9. *General Provisions.* (a) Nothing in this order shall be construed to impair or otherwise affect:

(i) the authority granted by law to an executive department or agency, or the head thereof; or

(ii) the functions of the Director of OMB 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,
January 20, 2025.

[FR Doc. 2025–02003
Filed 1–28–25; 11:15 am]
Billing code 3395–F4–P

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-7

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

Filed September 5, 2025

Exhibit 93

Grid EO

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.

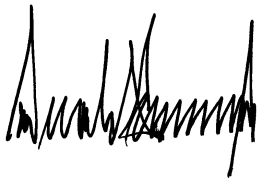
Sec. 4. *General Provisions.* (a) Nothing in this order shall be construed to impair or otherwise affect:

(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

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-7

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

Filed September 5, 2025

Exhibit 94

NY Times Coal Article

Trump Signs Orders Aimed at Reviving a Struggling Coal Industry

The moves include loosening environmental rules, but it is unclear how much they can help reverse the sharp decline in coal power over the last two decades.

Listen to this article · 7:58 min Learn more

By Brad Plumer and Mira Rojanasakul
Reporting from Washington

April 8, 2025

President Trump signed a flurry of executive orders Tuesday aimed at expanding the mining and burning of coal in the United States, in an effort to revive the struggling industry.

One order directs federal agencies to repeal any regulations that "discriminate" against coal production, to open new federal lands for coal mining and to explore whether coal-burning power plants could serve new A.I. data centers. Mr. Trump also said he would waive certain air-pollution restrictions adopted by the Biden administration for dozens of coal plants that were at risk of closing down.

In a move that could face legal challenges, Mr. Trump directed the Energy Department to develop a process for using emergency powers to prevent unprofitable coal plants from shutting down in order to avert power outages. Mr. Trump proposed a similar action in his first term but eventually abandoned the idea after widespread opposition.

Flanked by dozens of miners in white hard hats at the White House, Mr. Trump said he was also instructing the Justice Department to identify and fight state and local climate policies that were "putting our coal miners out of business." He added that he would issue "guarantees" that future administrations could not adopt policies harmful to coal, but did not provide details.

“This is a very important day to me because we’re bringing back an industry that was abandoned despite the fact that it was the best, certainly the best in terms of power, real power,” Mr. Trump said.

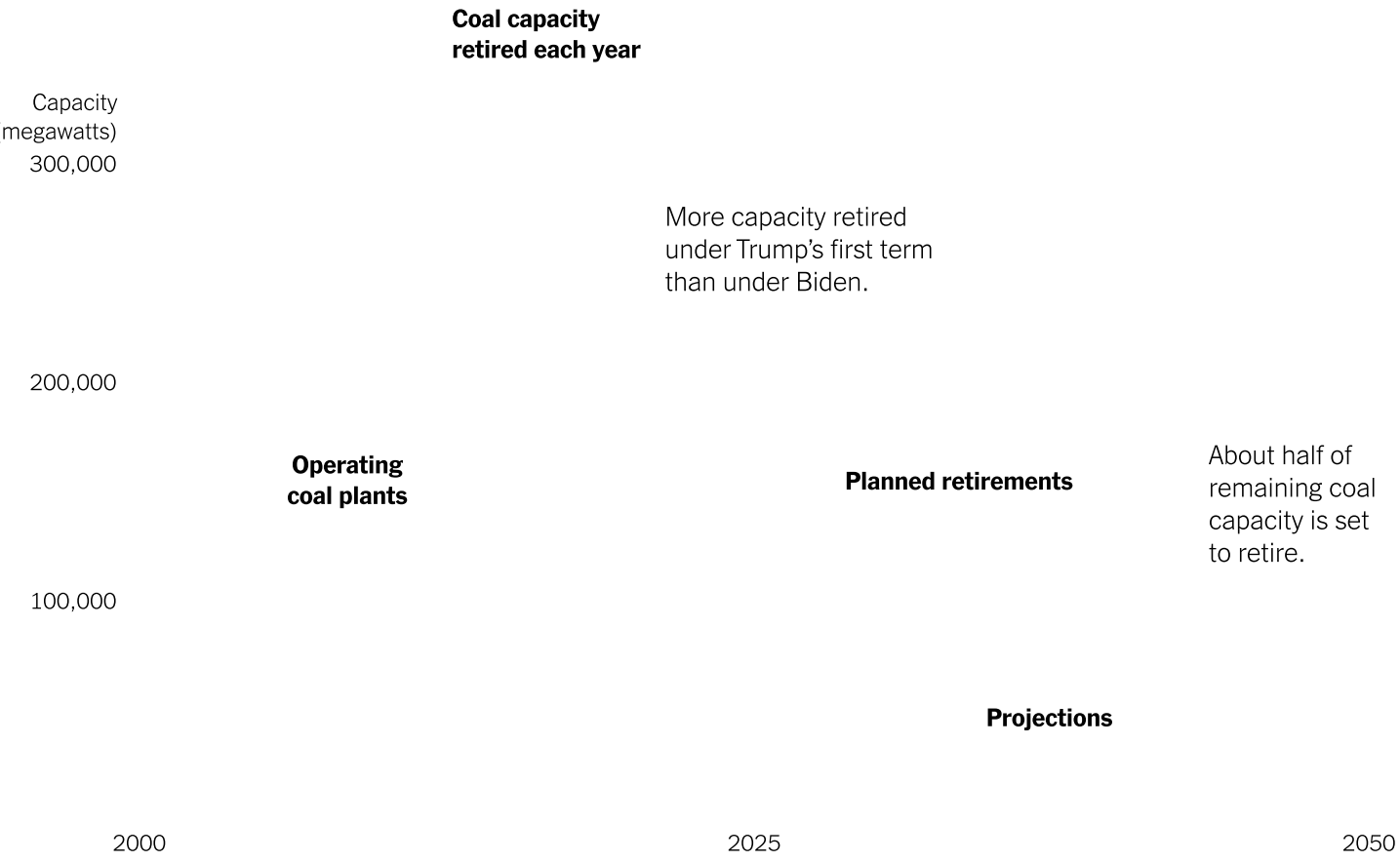
In recent weeks, Mr. Trump, Chris Wright, the energy secretary, and Doug Burgum, the interior secretary, have all spoken about the importance of coal. The two cabinet members sat in the front row at the White House ceremony, which was attended by members of Congress from Wyoming, Kentucky, West Virginia and other coal-producing states.

“Beautiful clean coal,” Mr. Trump told the gathering. “Never use the word ‘coal’ unless you put ‘beautiful, clean’ before it.”

Coal is the most polluting of all fossil fuels when burned, and accounts for roughly 40 percent of the world’s industrial carbon dioxide emissions, the main driver of global warming. It releases other pollutants, including mercury and sulfur dioxide, that are linked to heart disease, respiratory problems and premature deaths. Coal mining and the resulting coal ash from power plants can also present environmental problems.

Over the past two decades, the use of coal has fallen precipitously in the United States, as utilities have switched to cheaper and cleaner electricity sources like natural gas, wind and solar power. That transition has been the biggest reason for the drop in U.S. emissions since 2005.

Coal power has declined sharply — and more retirements are coming.



Source: Global Energy Monitor and New York Times reporting. • Note: Includes coal capacity added. • By Mira Rojanasakul/The New York times

It is unclear how much Mr. Trump could reverse that decline. In 2011, the nation generated nearly half of its electricity from coal; last year, that fell to just 15 percent. Utilities have already closed hundreds of aging coal-burning units and have announced retirement dates for roughly half of the remaining plants.

In recent years, growing interest in artificial intelligence and data centers has fueled a surge in electricity demand, and utilities have decided to keep more than 50 coal-burning units open past their scheduled closure dates, according to America's Power, an industry trade group. And as the Trump administration moves to loosen pollution limits on coal power — including regulations applied to carbon dioxide and mercury — more plants could stay open longer, or run more frequently.

"You know, we need to do the A.I., all of this new technology that's coming on line," Mr. Trump said on Tuesday. "We need more than double the energy, the electricity, that we currently have."

Yet a major coal revival is unlikely, some analysts said.

“The main issue is that most of our coal plants are older and getting more expensive to run, and no one’s thinking about building new plants,” said Seth Feaster, a data analyst who focuses on coal at the Institute for Energy Economics and Financial Analysis, a research firm. “It’s very hard to change that trajectory.”

During his first term, Mr. Trump sought to prevent unprofitable coal plants from closing, using emergency authority that is normally reserved for fleeting crises like natural disasters. But that idea brought a fierce blowback from oil and gas companies, grid operators and consumer groups, who said it would drive up electricity bills, and the administration eventually backed away from the idea.

If the idea was tried again today, it would be likely to lead to lawsuits, said Ari Peskoe, director of the Electricity Law Initiative at Harvard Law School. “But there’s not a lot of litigation history here,” he said. “Typically these emergency orders last for no longer than 90 days.”

Ultimately, Mr. Trump struggled to fulfill his first-term pledge of rescuing the coal industry. Despite the fact that his administration repealed numerous climate regulations and appointed a coal lobbyist to lead the Environmental Protection Agency, 75 coal-fired power plants closed, and the industry shed about 13,000 jobs during his presidency.

Coal’s decline continued under President Joseph R. Biden Jr., who sought to move the country away from the fossil fuel altogether in an effort to fight climate change. Last year, his administration issued a sweeping E.P.A. rule that would have forced all of the nation’s coal plants to either install expensive equipment to capture and bury their carbon dioxide emissions or shut down by 2039.

This year, upon returning to office, Mr. Trump ordered the E.P.A. to repeal that rule. And Trump administration officials have repeatedly warned that shutting down coal plants would harm power supplies. Unlike wind and solar energy, coal plants can run at any hour of the day, making them useful when electricity demand spikes.

Some industry executives who run the nation’s electric grids have also warned that the country could face a greater risk of blackouts if too many coal plants retire too quickly, especially since power companies have faced delays in bringing new gas, wind and solar plants online, as well as in adding battery storage and transmission lines.

“For decades, most people have taken electricity and coal for granted,” said Michelle Bloodworth, chief executive of America’s Power. “This complacency has led to damaging federal and state policies that have caused the premature retirement of coal plants, thus weakening our electric grid and threatening our national security.”

Yet coal opponents say that keeping aging plants online can worsen deadly air pollution and increase energy costs. Earlier this year, PJM Interconnection, which oversees a large grid in the Mid-Atlantic, ordered a power plant that burns coal and another that burns oil to stay open until 2029, four years past their planned retirement date, to reduce the risk of power outages. The move could ultimately cost utility customers in the area of more than $720 million.

“Coal plants are old and dirty, uncompetitive and unreliable,” said Kit Kennedy, managing director for power at the Natural Resources Defense Council, an environmental group. “The Trump administration is stuck in the past, trying to make utility customers pay more for yesterday’s energy. Instead, it should be doing all it can to build the electricity grid of the future.”

Brad Plumer is a Times reporter who covers technology and policy efforts to address global warming.

Mira Rojanasakul is a Times reporter who uses data and graphics to cover climate and the environment.

A version of this article appears in print on , Section A, Page 15 of the New York edition with the headline: Trump Signs Orders Aimed At Reviving Coal Industry

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-7

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

Filed September 5, 2025

Exhibit 95

Eddystone May Order

Order No. 202-25-4

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 electricity grid operated by PJM Interconnection (PJM) due to a shortage of facilities for the generation of electric energy, resource adequacy concerns, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

Emergency Situation

PJM has recently stated its system faces "growing resource adequacy concern" due to load growth, the retirement of dispatchable resources, and other factors.[1] Upcoming retirements, including the planned retirement of Unit 3 and Unit 4 of the Eddystone Generating Station in Eddystone, Pennsylvania, will exacerbate these resource adequacy issues.

PJM indicates that resource constraints could exist within the service territory under peak load conditions, stating that "available generation capacity may fall short of required reserves in an extreme planning scenario."[2] In its February 2023 assessment "*Energy Transition in PJM: Resource Retirements, Replacements & Risks,*" PJM highlights the increasing risk of reliability risk in the coming years due to the "potential timing mismatch between resource retirements, load growth and the pace of new generation entry" under "low new entry" scenarios for renewable generation.[3]

In December 2024, PJM filed revisions with the Federal Energy Regulatory Commission (FERC) to Part VII of its Open Access Transmission Tariff, known as the Reliability Resource Initiative (RRI), to address near-term resource adequacy concerns. In a February 2025 order, FERC accepted the revisions and found "the possibility of a resource adequacy shortfall driven by significant load growth, premature retirements, and delayed new entry."[4] In March 2025 congressional testimony, PJM found "a growing resource adequacy concern" due to a combination of load growth, the retirement of dispatchable resources, and other factors.[5] Through 2030, PJM anticipates reliability risk from increasing electricity demand, generator retirement outpacing new resource construction, and characteristics of resources in PJM's interconnection queue.[6]

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[1] https://www.pjm.com/-/media/DotCom/library/reports-notices/testimony/2025/20250325-asthana-testimony-us-house-subcommittee-on-energy.pdf
[2] https://insidelines.pjm.com/pjm-summer-outlook-2025-adequate-resources-available-for-summer-amid-growing-risk/
[3] https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx
[4] https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250211-3120
[5] https://www.pjm.com/-/media/DotCom/library/reports-notices/testimony/2025/20250325-asthana-testimony-us-house-subcommittee-on-energy.pdf
[6] Ibid.

Constellation Energy owns the Eddystone Generating Station, which includes Unit 3 and Unit 4, each of which has a nameplate capacity of 380 MW. Units 3 and 4 have a planned retirement date of May 31, 2025. The retirement of these units would further decrease available dispatchable generation within PJM's service territory.

Pursuant to Executive Order 14262, *Strengthening the Reliability and Security of the United States Electric Grid* (EO 14262), DOE is developing a methodology to identify current and anticipated reserve margins for all regions of the bulk-power system regulated by the Federal Energy Regulatory Commission. EO 14262 requires this methodology to be published by July 7, 2025, and 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 this methodology to further evaluate Eddystone Units 3 and 4.

ORDER

Given the emergency nature of resource adequacy concerns, the declared state of national energy emergency, the responsibility of PJM to ensure maximum reliability on its system, and the ability of PJM to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, operational availability and economic dispatch of the aforementioned Eddystone Units 3 and 4 (Eddystone Units) is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination is based on, among other things:

- The emergency nature of the potential load stress due to aforementioned resource adequacy concerns, and the potential loss of power to homes and local businesses in the areas that may be affected by curtailments, presenting a risk to public health and safety.
- The potential shortage of electric energy, shortage of facilities for the generation of electric energy, and other causes in the region support the need for the Eddystone Units to contribute to system reliability.
- PJM's responsibility to ensure maximum reliability on its system, and, with the authority granted in this Order, its ability to identify and dispatch generation, including the Eddystone Units, necessary to meet the load demands.

This Order is limited in duration to align with the anticipated 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)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse

environmental impacts. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by PJM for reliability purposes.

Based on my determination of an emergency set forth above, I hereby order:

A. From the time this Order is issued on May 30, 2025, PJM and Constellation Energy shall take all measures necessary to ensure that Eddystone Units are available to operate. For the duration of this order, PJM is directed to take every step to employ economic dispatch of the units to minimize cost to ratepayers. Following conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Constellation Energy is directed to comply with all orders from PJM related to the availability and dispatch of the Eddystone Units.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units through the expiration of the Order. PJM shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Eddystone Units have operated in compliance with the allowances contained in this Order.

C. All operation of the Eddystone Units 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.

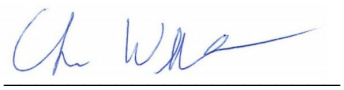
D. By June 15, 2025, PJM is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Eddystone Units consistent with the public interest. PJM shall also provide such 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. In addition, PJM and Constellation Energy are directed to file with the Federal Energy Regulatory Commission any tariff revisions or waivers necessary to effectuate this order. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

F. This Order shall not preclude the need for the Eddystone Units to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. This Order shall be effective upon its issuance, and shall expire at 5:03 PM EDT on August 28, 2025, with the exception of the reporting requirements in paragraph D.

H. Issued in Simi Valley, California, at 5:03 PM Eastern Daylight Time on this 30th day of May 2025.



Chris Wright
Secretary of Energy

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-7

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

Filed September 5, 2025

Exhibit 96

July Resource Adequacy Report

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 approach[2] 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 metrics[6] 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:

$$\frac{100\ MWh\ (of\ unserved\ energy)}{10{,}000{,}000\ MWh\ (of\ total\ energy\ delivered\ in\ a\ year)} x100 = 0.001\ percent$$

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%.

10. 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.

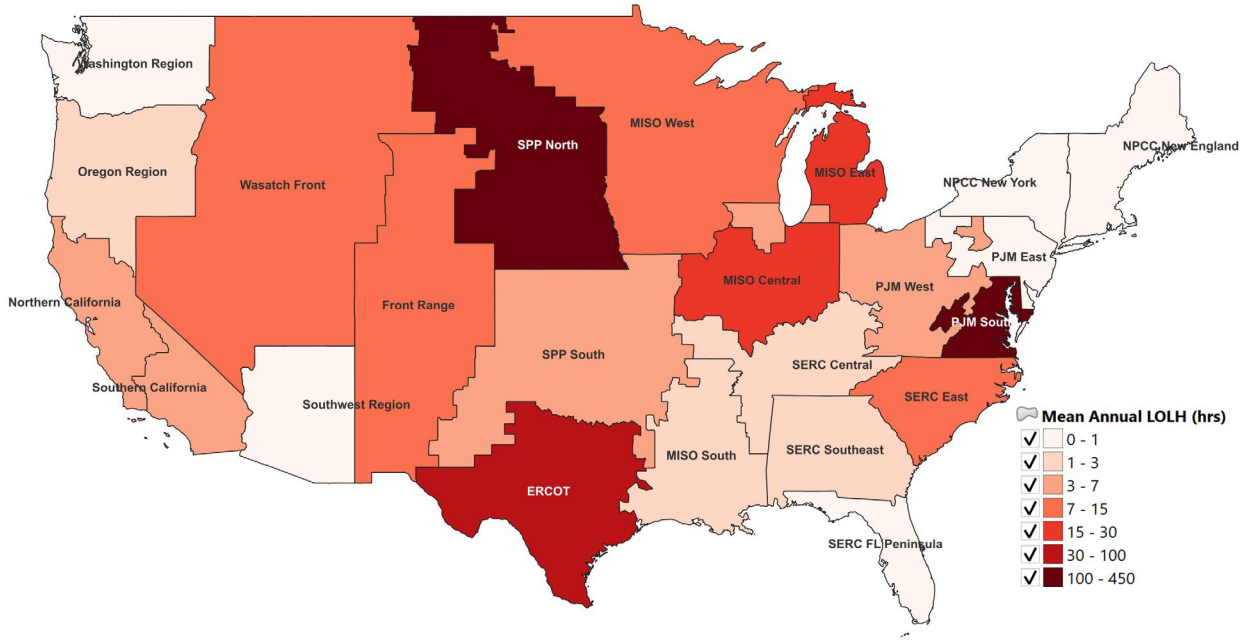


Figure 1. Mean Annual LOLH by Region (2030) – Plant Closures

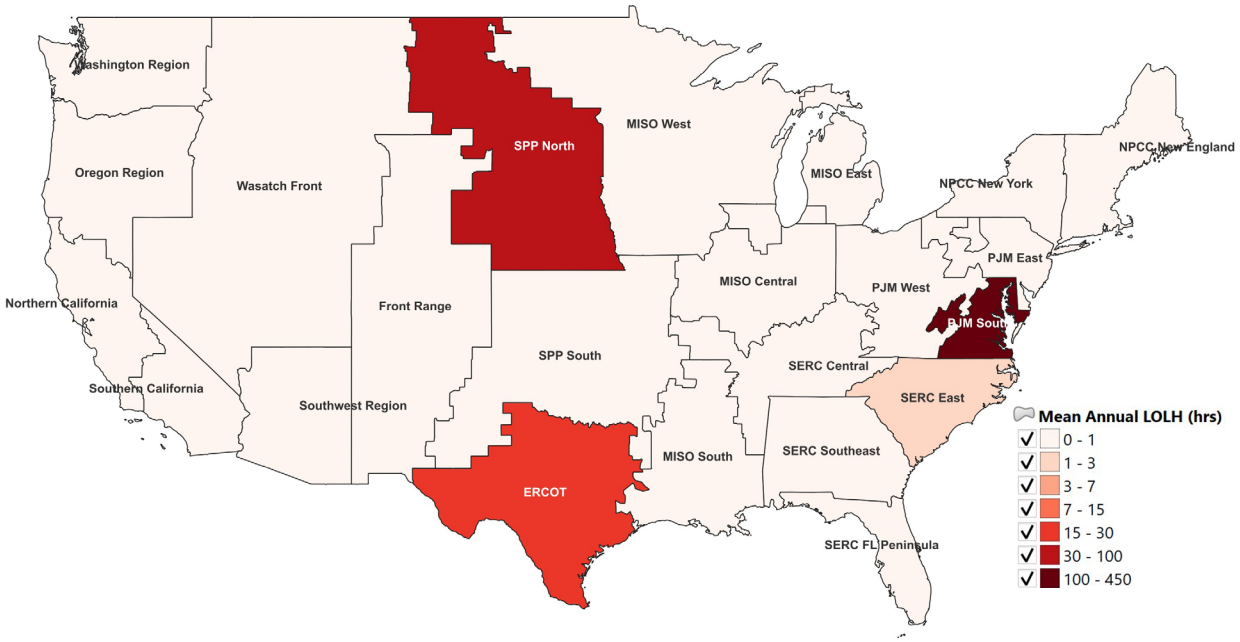


Figure 2. Mean Annual LOLH by Region (2030) – No Plant Closures

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

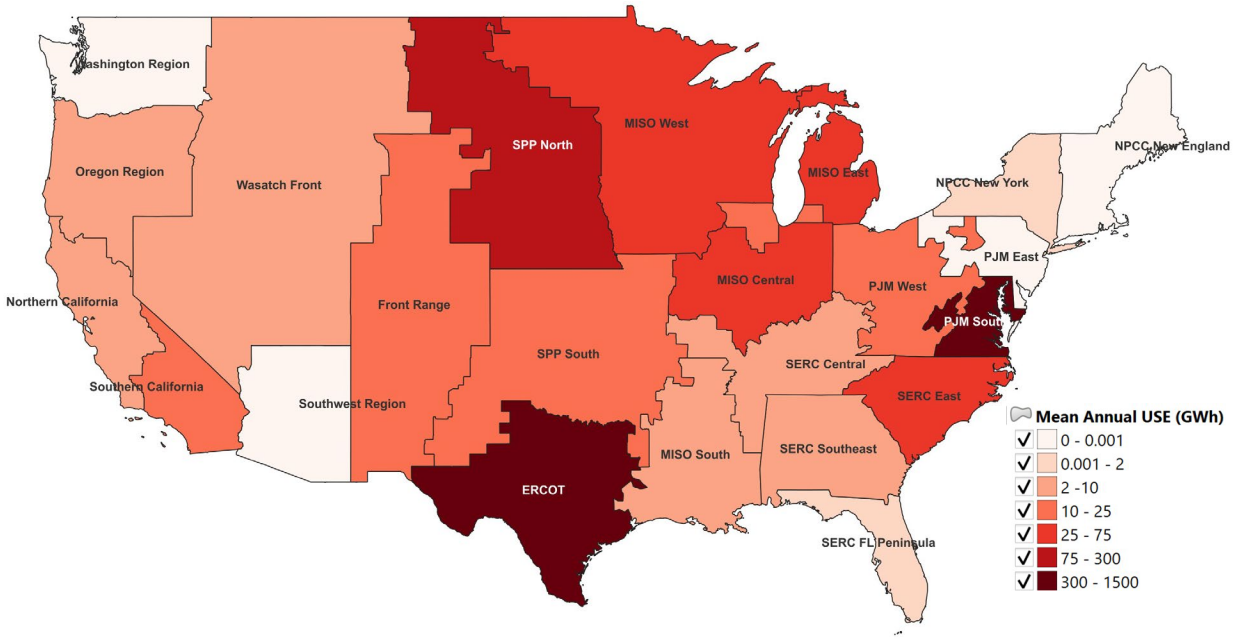


Figure 3. Mean Annual NUSE by Region (2030) -Plant Closures

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**:

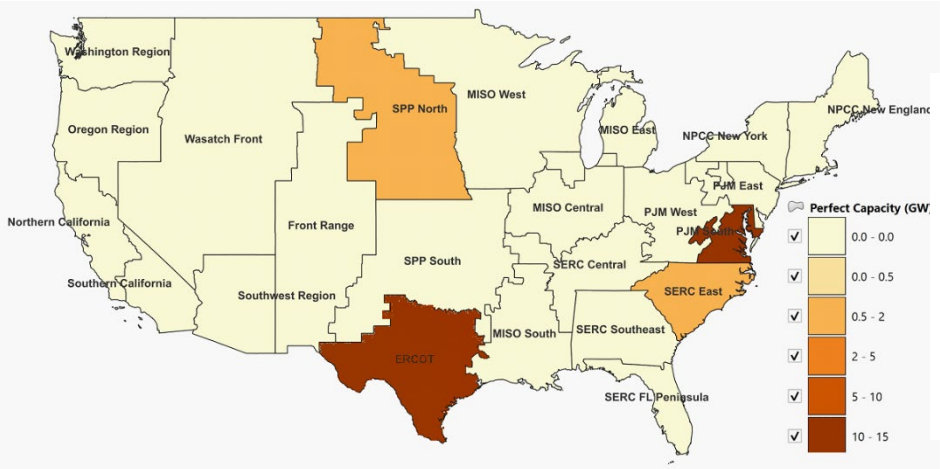
- **PJM**: 214 hours/year average, 0.066% normalized unserved energy, 644 hours in worst year, max 36% of load lost.
- **SPP**: 48 hours/year average, 0.008% normalized unserved energy, max 19% load lost.
- **ERCOT**: 20 average hours, 0.028% normalized unserved energy, 101 max hours/year, peak shortfall of 27%.
- **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.



	2024-Current System (MW)	2030-No Plant Closures (MW)
PJM	2400	10,500
SERC-E		500
SPP-N		1,500
ERCOT	1600	10500
Total	4000	23000

Perfect Capacity/Additions

Figure 4. Tuned Perfect Capacity (MW) By Region

1 Modeling Methodology

The methodology uses a zonal PLEXOS[13] 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 ITCS[16] 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.

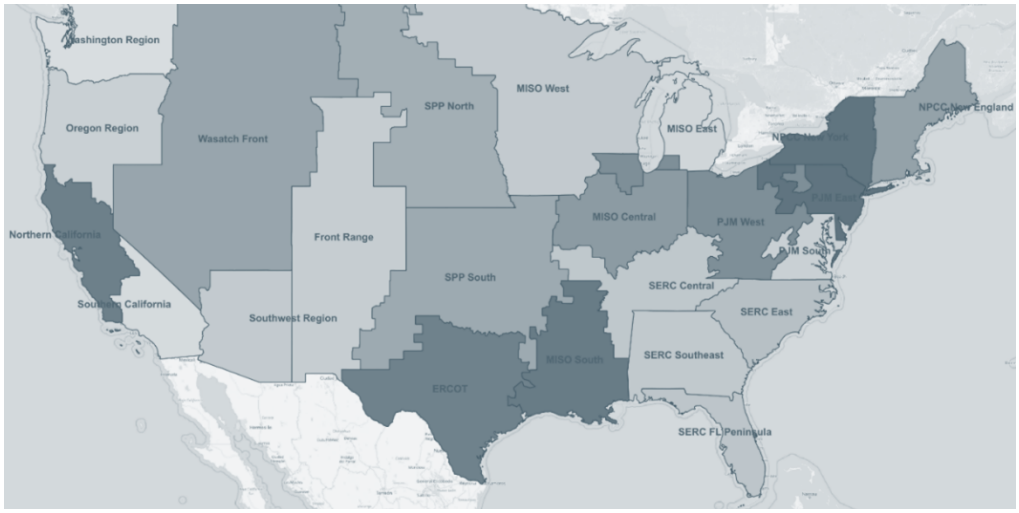


Figure 5. TPRs used in NERC ITCS

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.

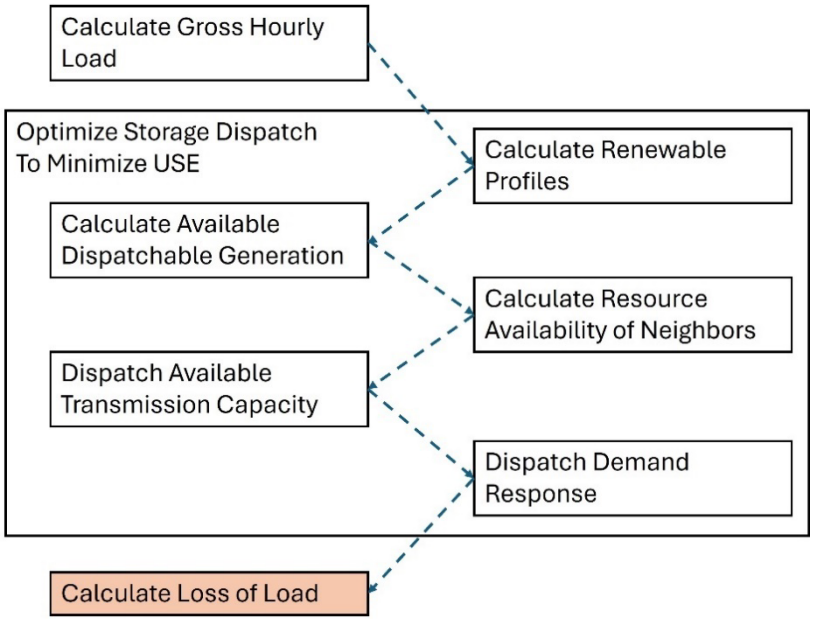


Figure 6. Simplified Overview of Model

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.

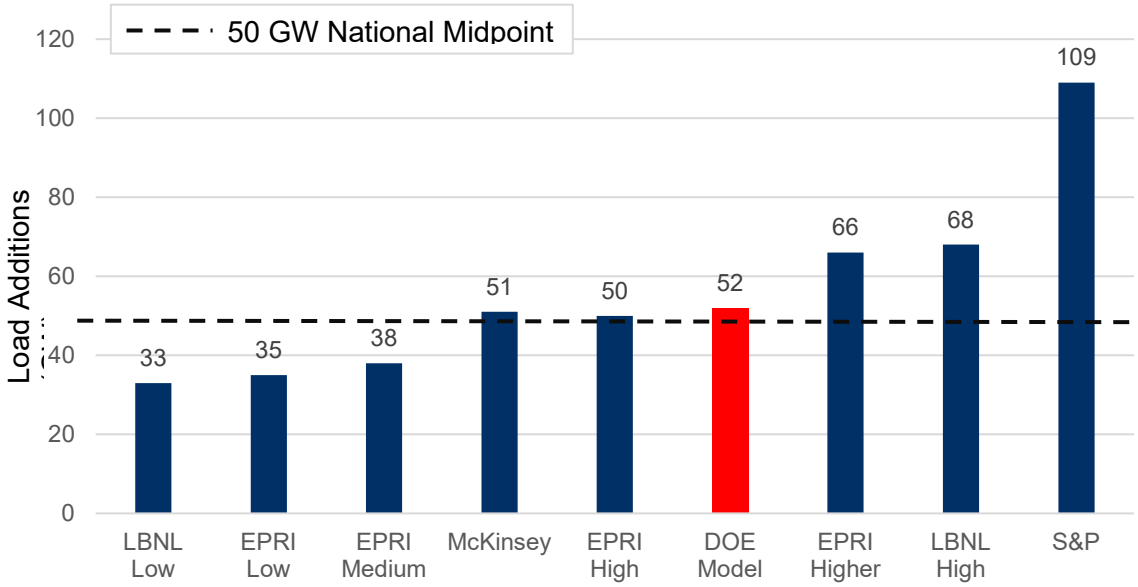


Figure 7. 2024 to 2030 Projected Data Center Load Additions

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.

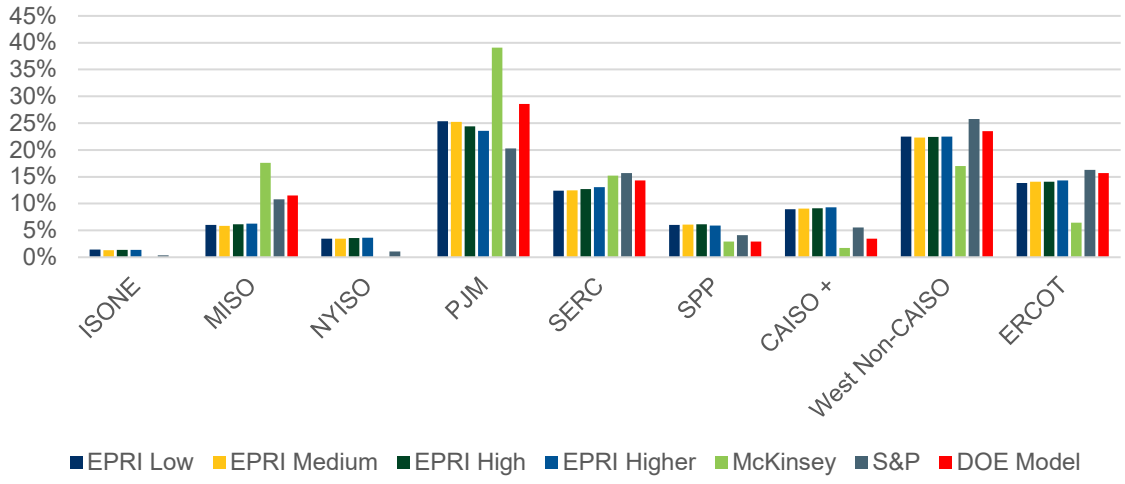


Figure 8. New Data Center Build (% Split by ISO/RTO) (2030 Estimated)

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.

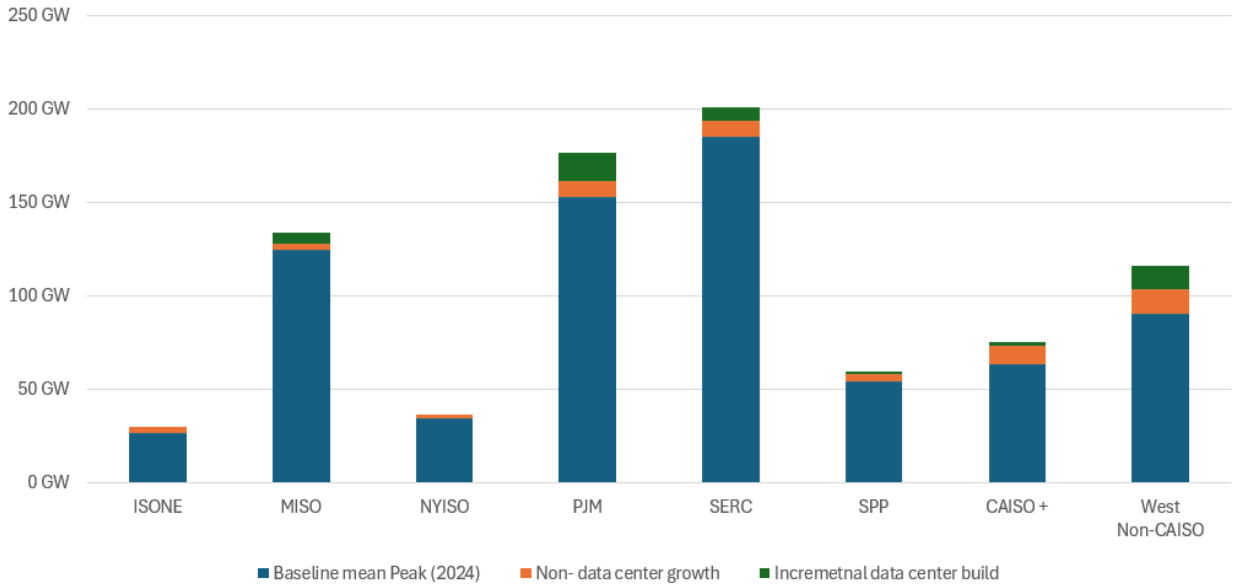


Figure 9. Mean Peak Load by RTO (Current Case vs 2030 Case)

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 MISO[25]

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.

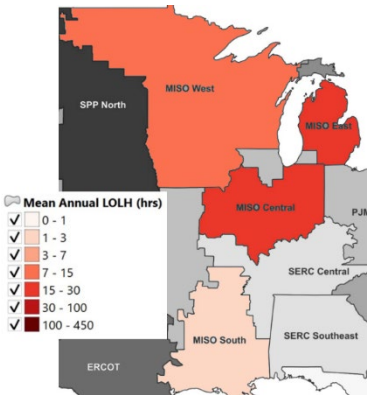


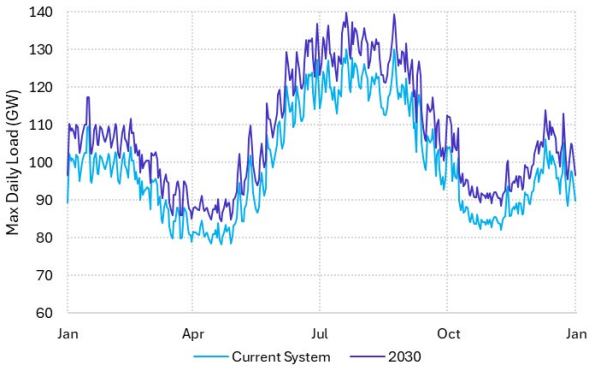
Table 2. Summary of MISO Reliability Metrics

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.



Subregion	2024	2030
MISO-W	37,913	40,981
MISO-C	35,387	39,243
MISO-S	36,476	38,596
MISO-E	23,167	23,758
Total	**130,136**	**139,846**

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.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
MISO-W	71,612	67,453	77,605
MISO-C	51,982	47,735	58,823
MISO-S	54,511	52,756	59,710
MISO-E	29,213	28,105	32,255
Total	**207,319**	**196,049**	**228,393**

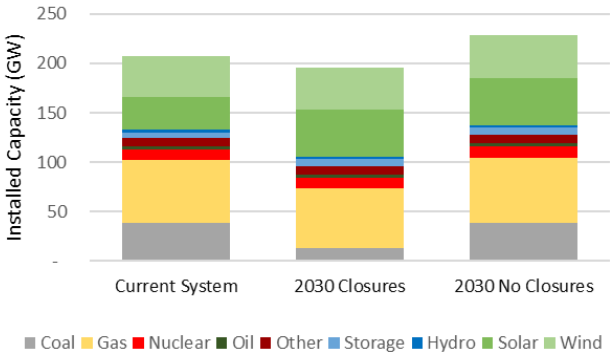


Figure 11. MISO Generation Capacity by Technology and Scenario

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

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

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

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

2.2 ISO-NE

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

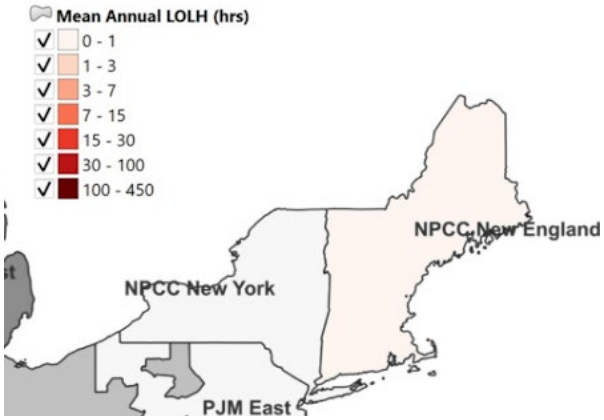
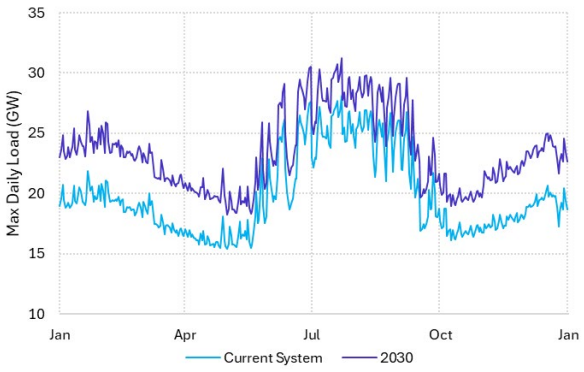


Table 4. Summary of ISO-NE Reliability Metrics

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

Load Assumptions

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



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

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

Generation Stack

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

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

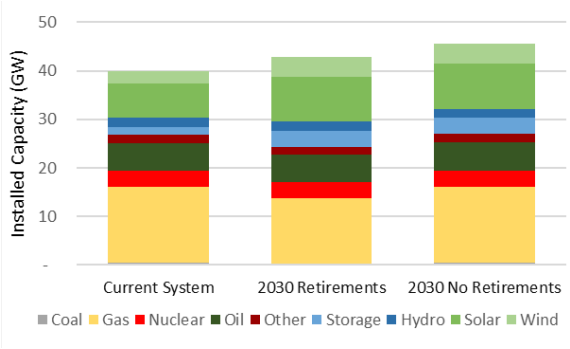


Figure 13. ISO-NE Generation Capacity by Technology and Scenario

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

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

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

2.3 NYISO

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

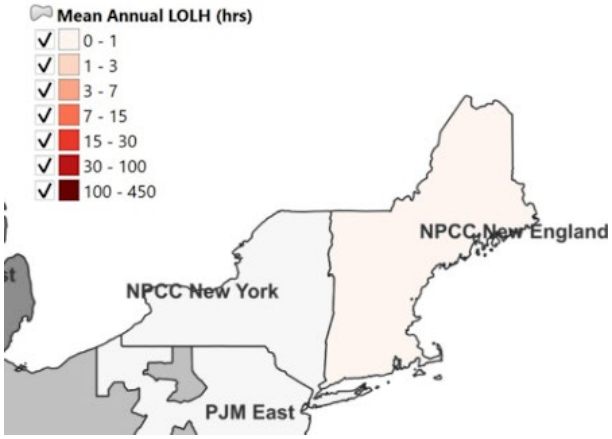
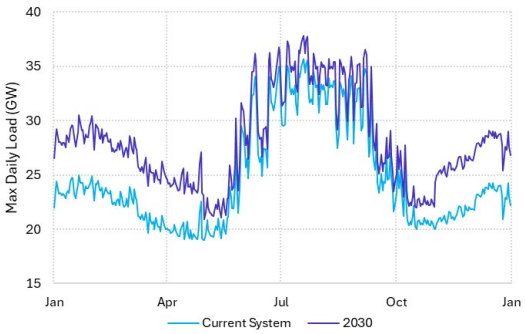


Table 6. Summary of NYISO Reliability Metrics

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

Load Assumptions

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



Subregion	2024	2030
NYISO	35,669	37,844
Total	**35,669**	**37,844**

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**

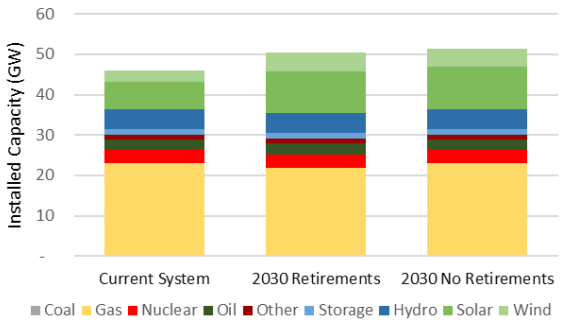


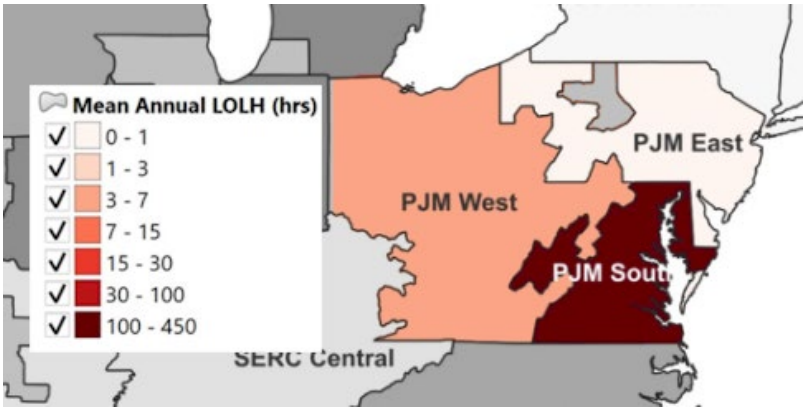
Figure 15. NYISO Generation Capacity by Technology and Scenario

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



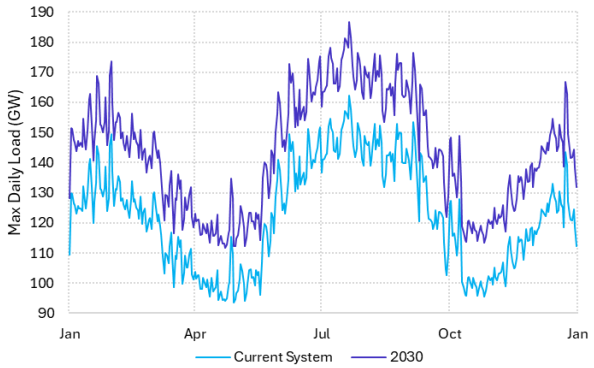
In the current system model, PJM experienced shortfalls, but they were below the required threshold. In the No Plant Closures case, shortfalls increased dramatically, with 214 average annual LOLH and peak unserved load reaching 17,620 MW, indicating growing strain even without retirements. In the Plant 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**

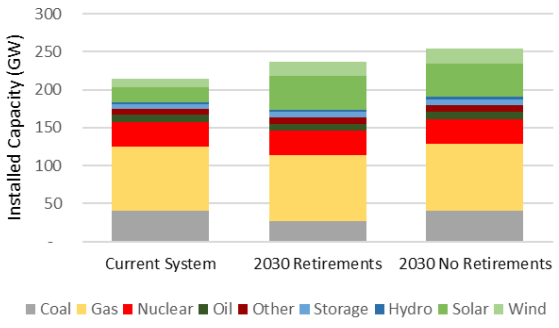


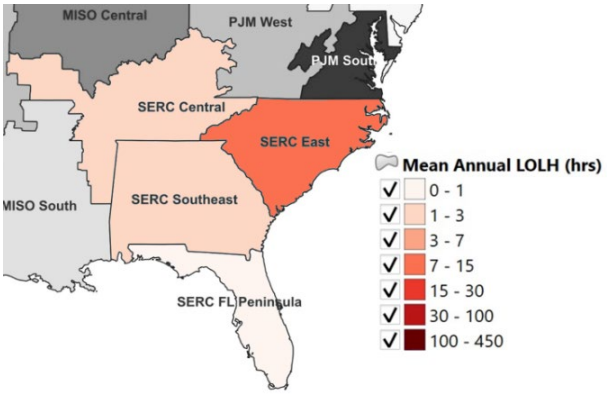
Figure 17. PJM Generation Capacity by Technology and Scenario

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



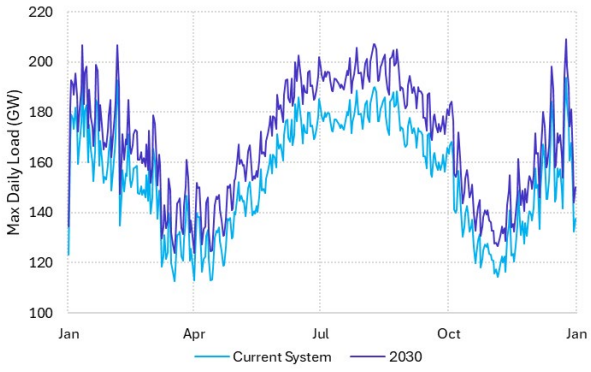
In the current system model and the No Plant Closures case, SERC maintained overall adequacy, though some subregions—particularly SERC-East—faced emerging winter reliability risks. In the Plant Closures case, shortfalls became more severe, with SERC-East experiencing increased unserved energy and loss 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**

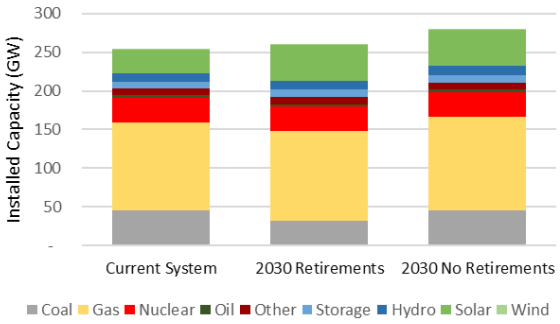


Figure 19. SERC Generation Capacity by Technology and Scenario

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.

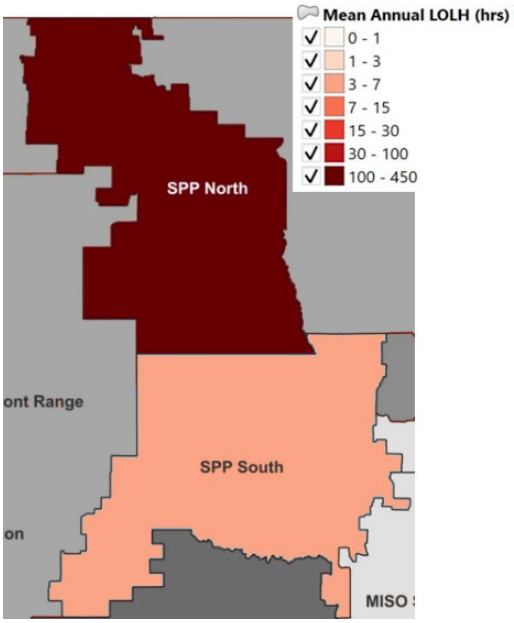
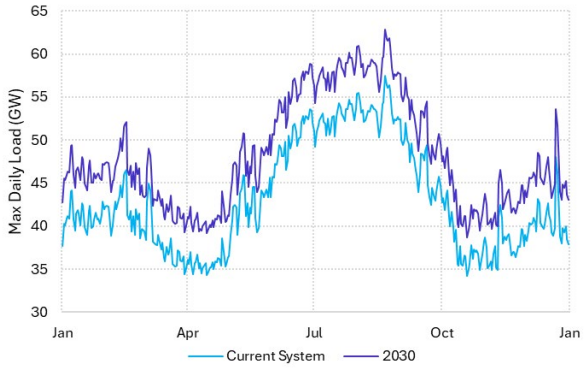


Table 12. Summary of SPP Reliability Metrics

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**

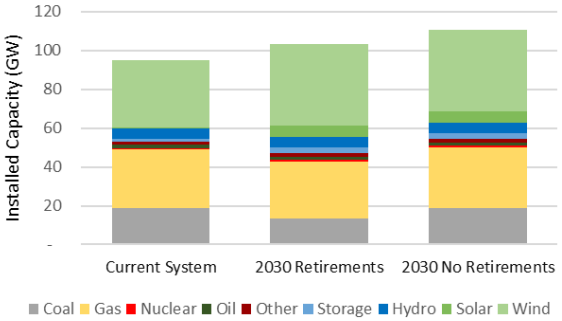


Figure 21. SPP Generation Capacity by Technology and Scenario

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.

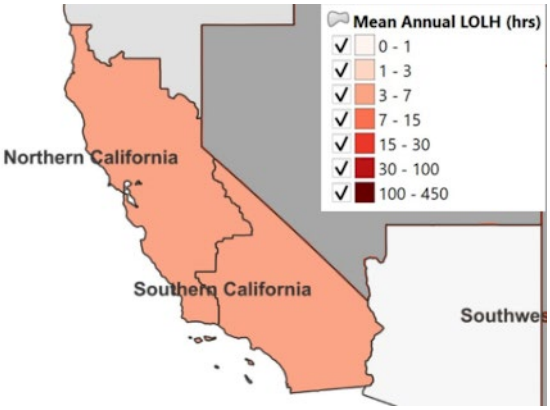
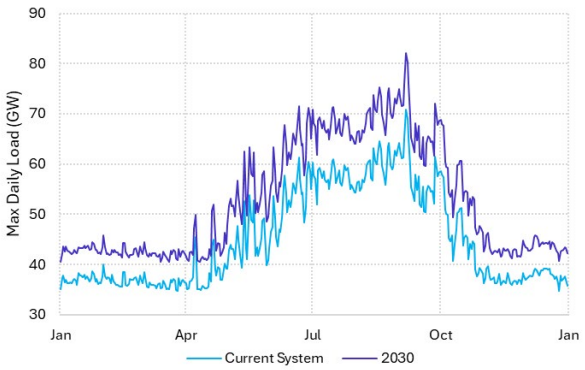


Table 14. Summary of CAISO+ Reliability Metrics

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**

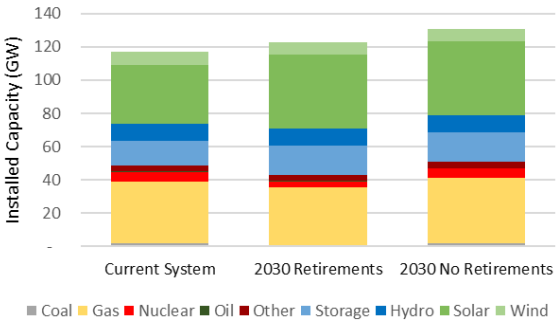


Figure 23. CAISO+ Generation Capacity by Technology and Scenario

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.

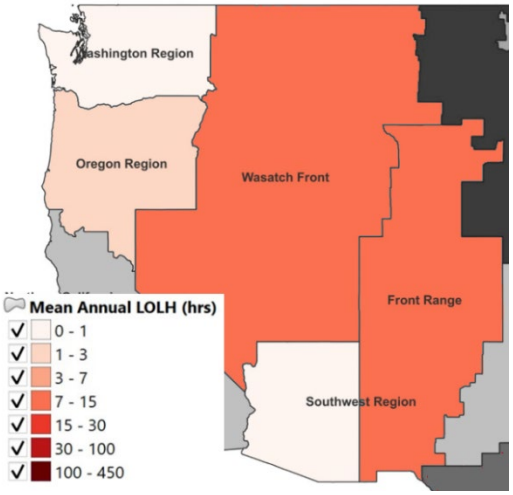
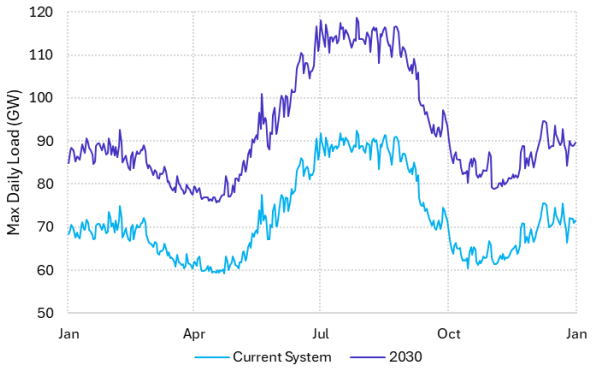


Table 16. Summary of West Non-CAISO Reliability Metrics

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**

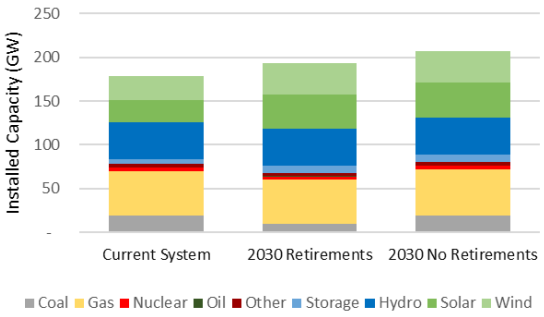


Figure 25. West Non-CAISO Generation Capacity by Technology and Scenario

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.

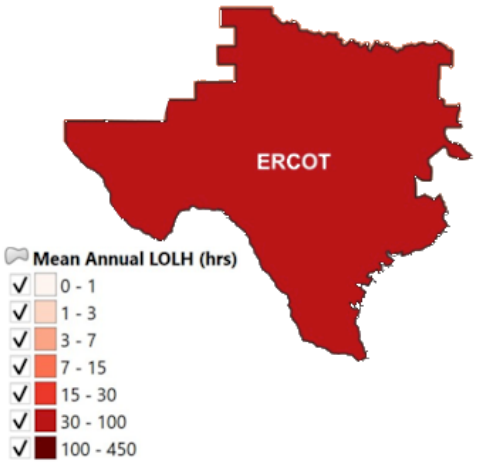
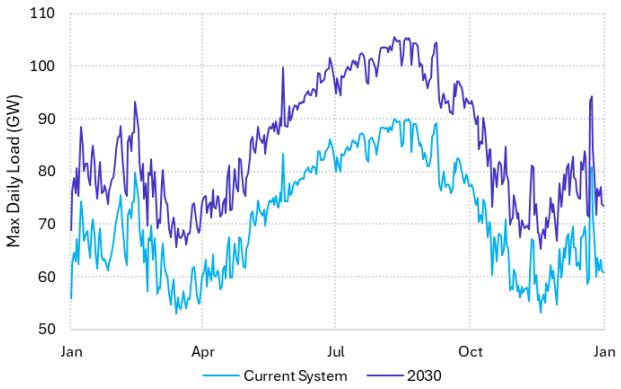


Table 18. Summary of ERCOT Reliability Metrics

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**

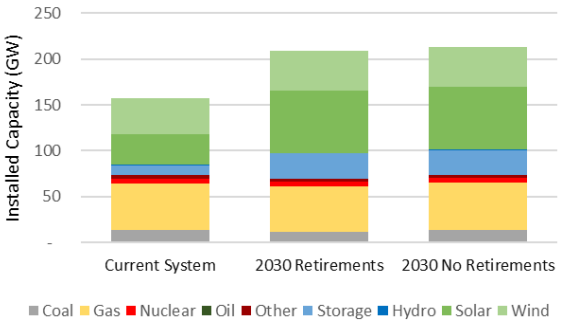


Figure 27. ERCOT Generation Capacity by Technology and Scenario

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 LTRAs[28], 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 capacities[29] 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.

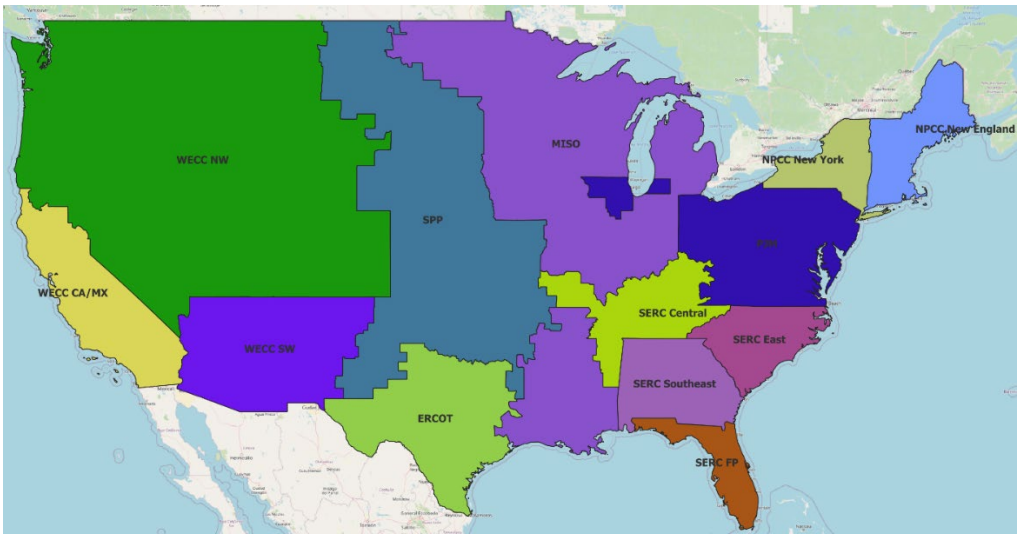


Figure A.1. NERC assessment areas.

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:

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

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

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

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

30. NREL, "Regional Energy Development System," https://www.nrel.gov/analysis/reeds/.

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

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

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

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

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

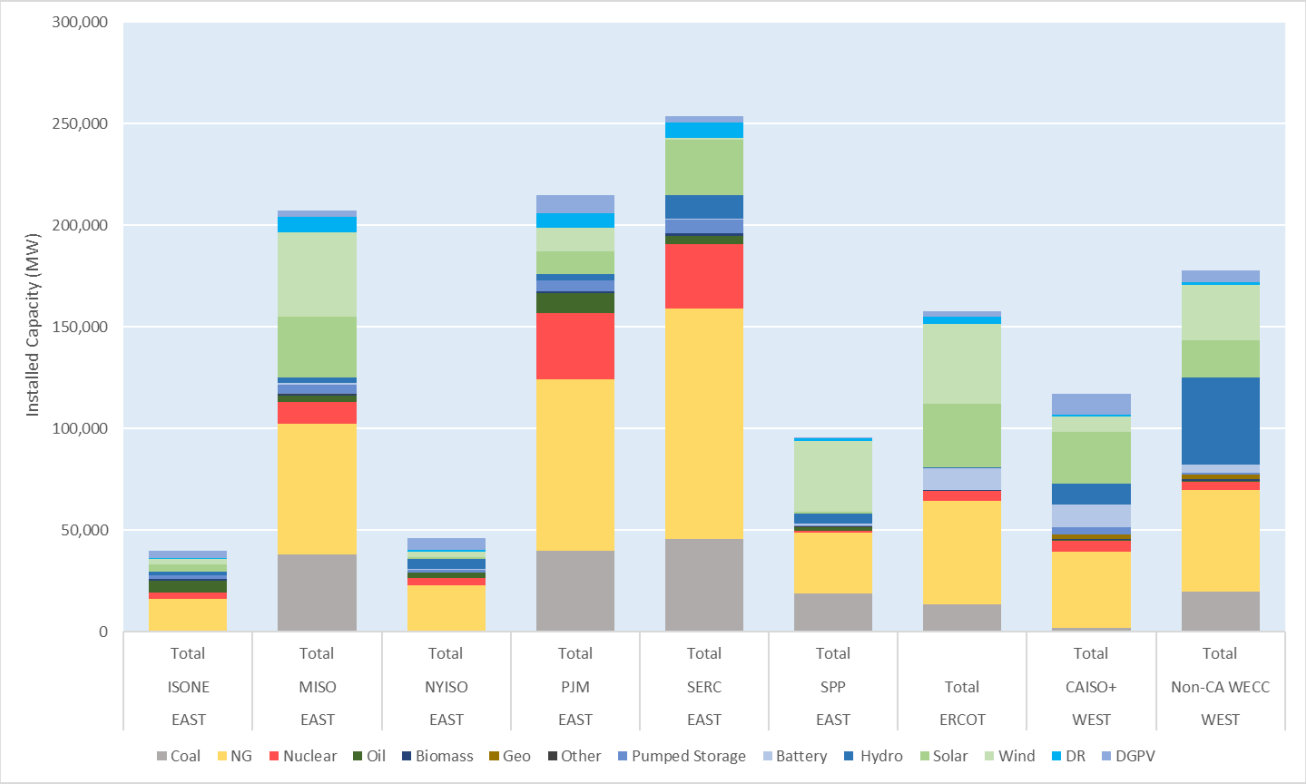


Figure A.2. Existing and Tier 1 capacities by NERC assessment area in 2024.

Forecasting 2030 Resource Mixes

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

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

Retirements

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

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

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

Generation Stack for Each Scenario

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

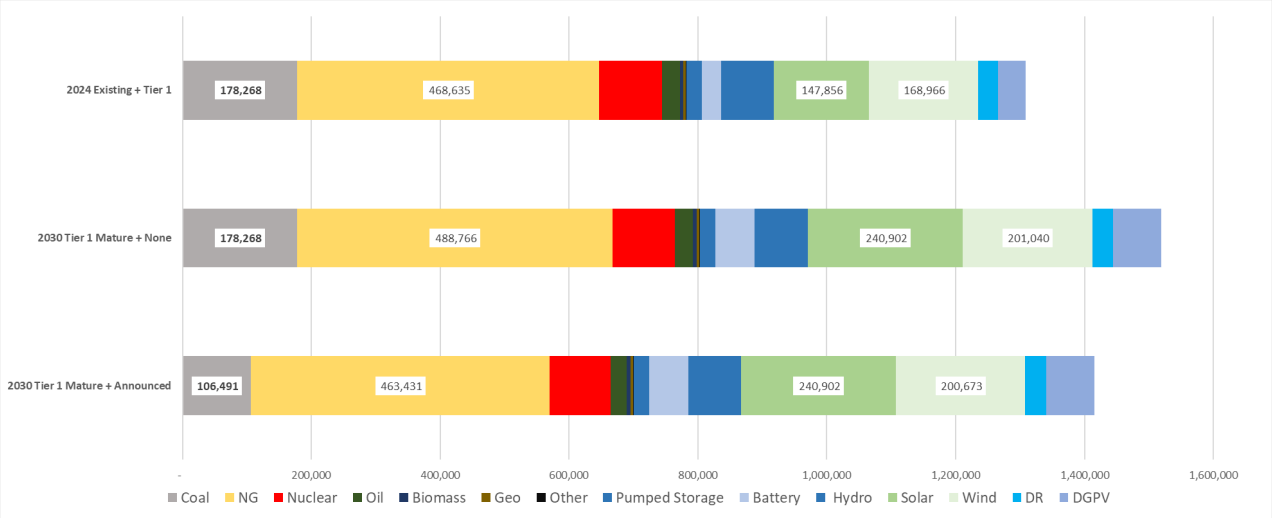


Figure A.9. Comparison of 2030 generation stacks for the various scenarios.

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

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

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

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

Appendix B - Representing Canadian Transfer Limits

Introduction

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

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

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

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

Methodology

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

Dataset Collection and Preparation

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

Underlying Hypothesis

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

Regression Model

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

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

Model Training, Validation, and Assessment

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

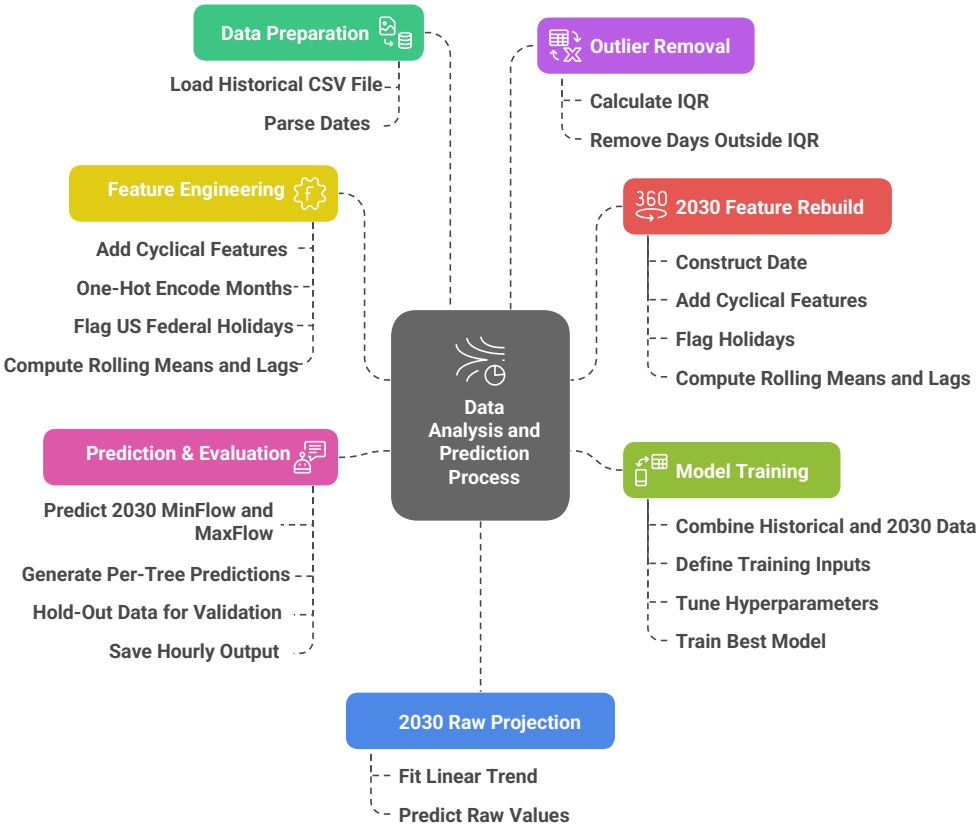


Figure B.1. Data analysis and prediction process.

Example Feature Importance for Predicting MaxFlow from Ontario to NYISO

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

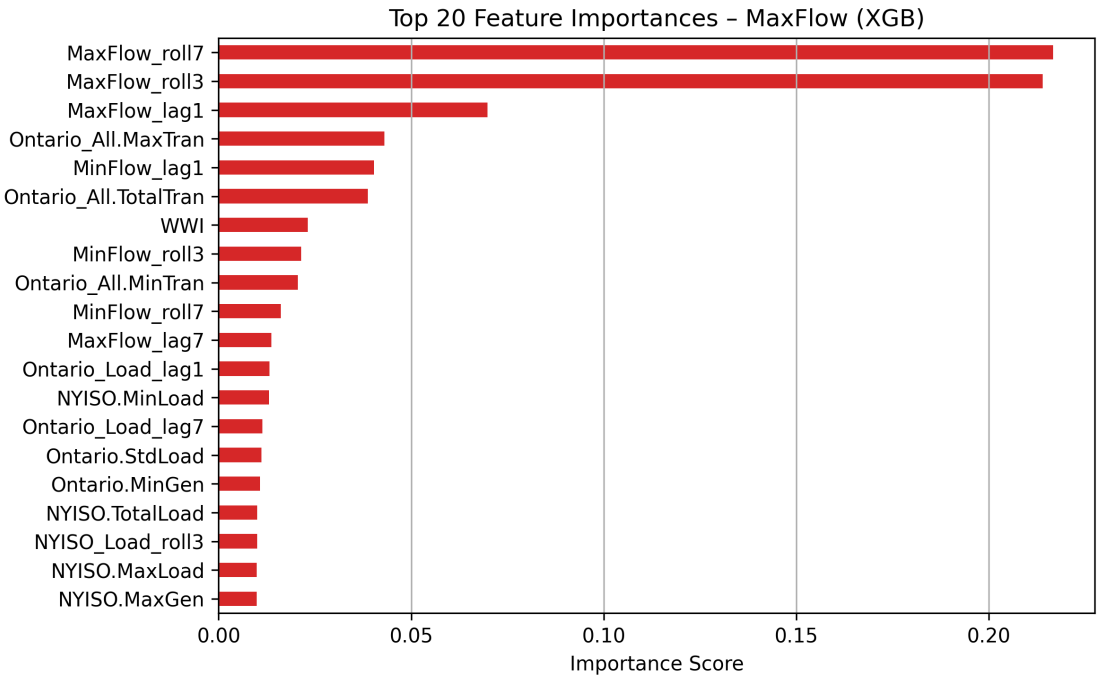


Figure B.2. Feature importance for predicting the hourly maximum energy transfer (MaxFlow) between NYISO and Ontario. XGB = eXtreme Gradient Boosting.

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

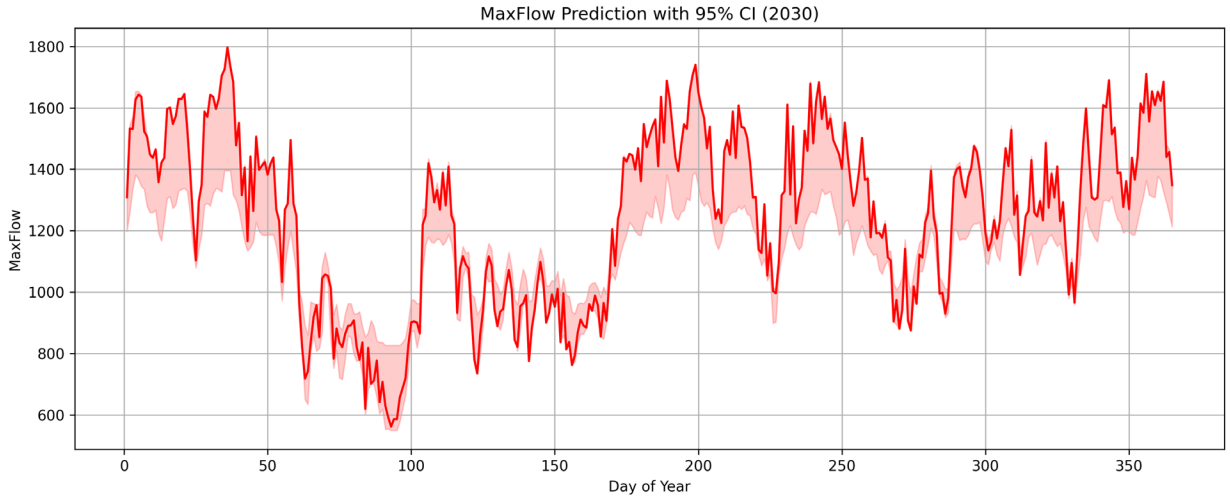


Figure B.3. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI).

Model Performance

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

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

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

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

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

Maximum flow predictions: Ontario to New York

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

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

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

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

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

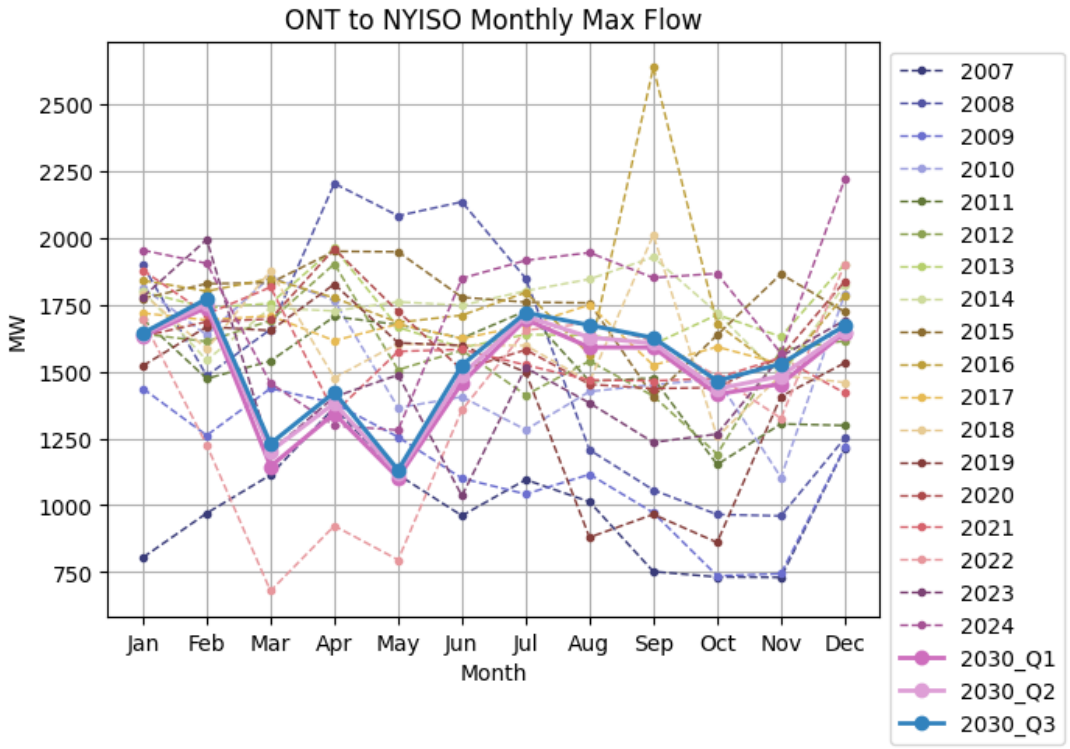


Figure B.4. Monthly maximum energy transfer between Ontario (ONT) and New York (NYISO).

The team used robust validation metrics to justify these results. When trained on daily data from the 2010–2024 period—incorporating 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.

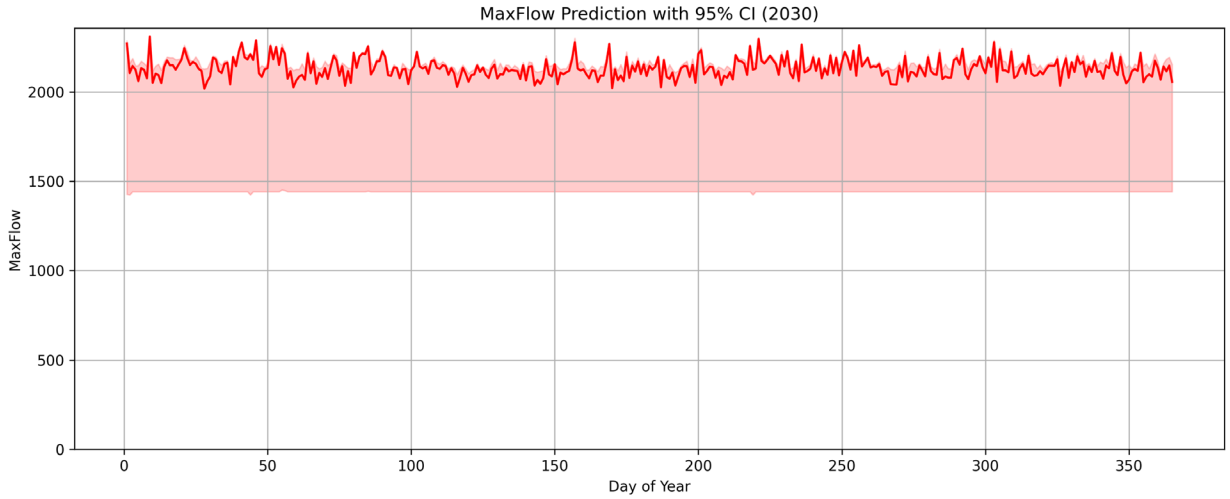


Figure B.5. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between British Columbia and the Pacific Northwest.

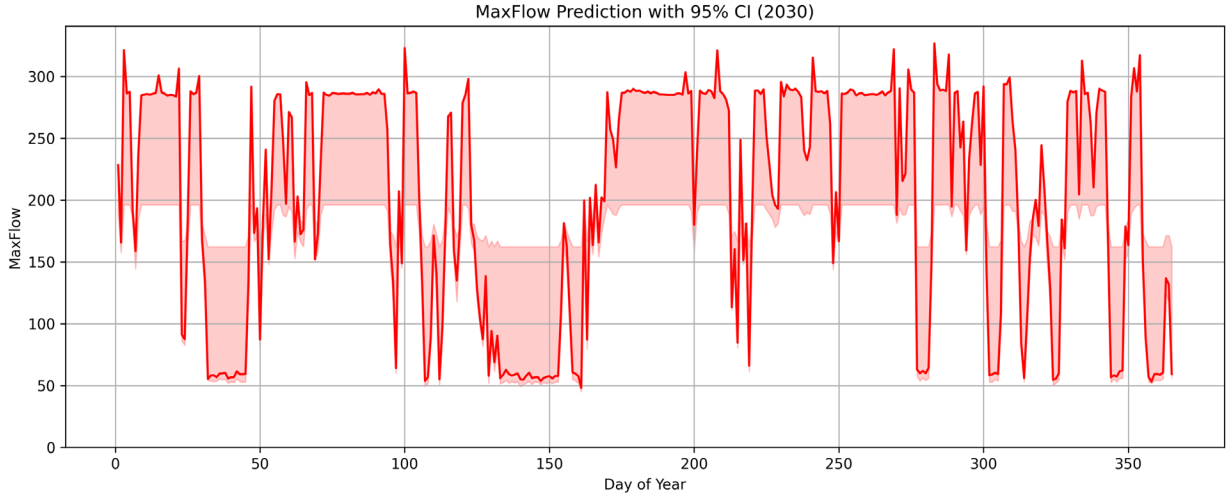


Figure B.6. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between AESO and Montana.

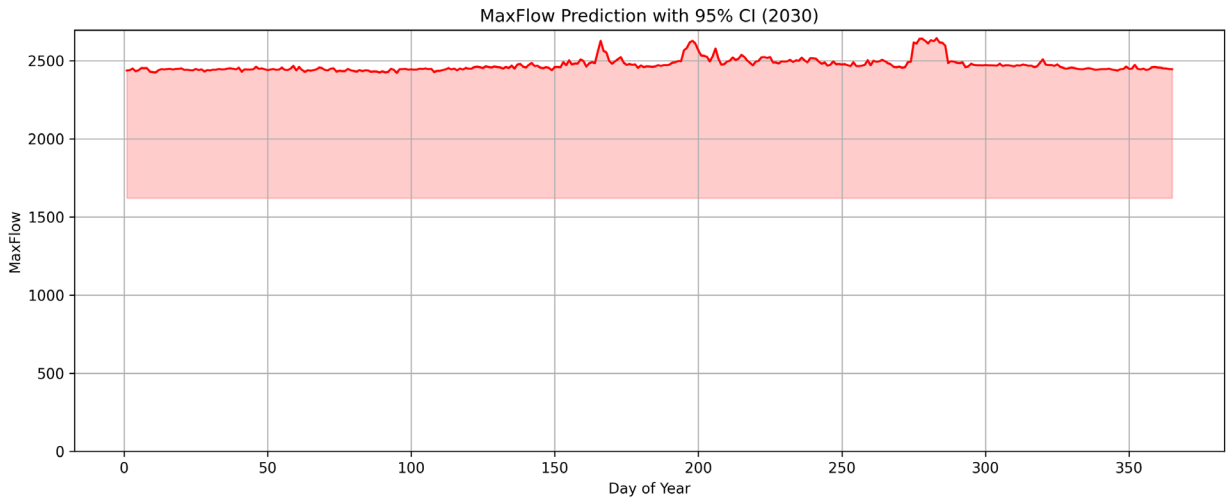


Figure B.7. Projected 2030 maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Manitoba and MISO.

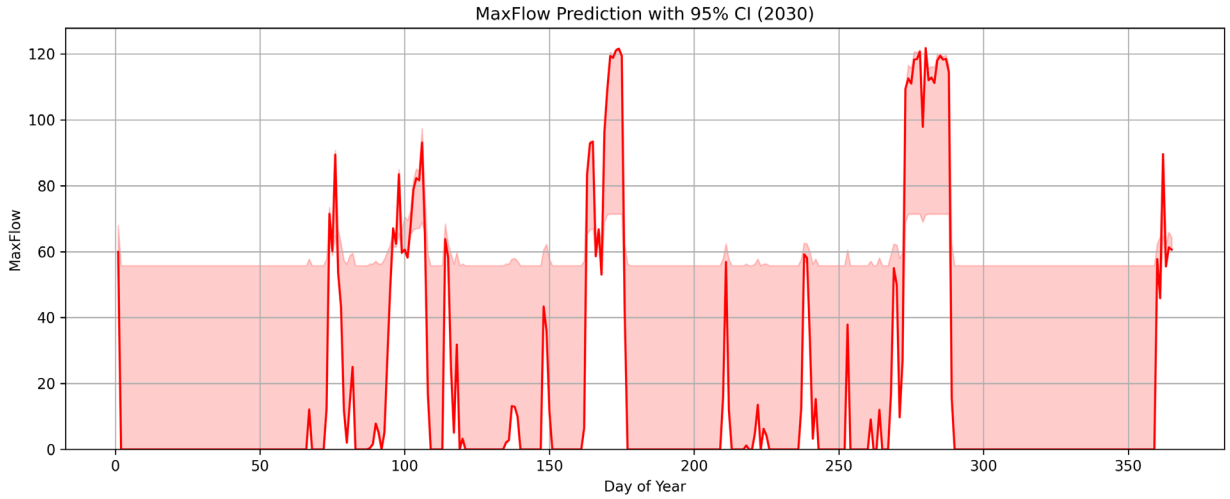


Figure B.8. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and MISO West.

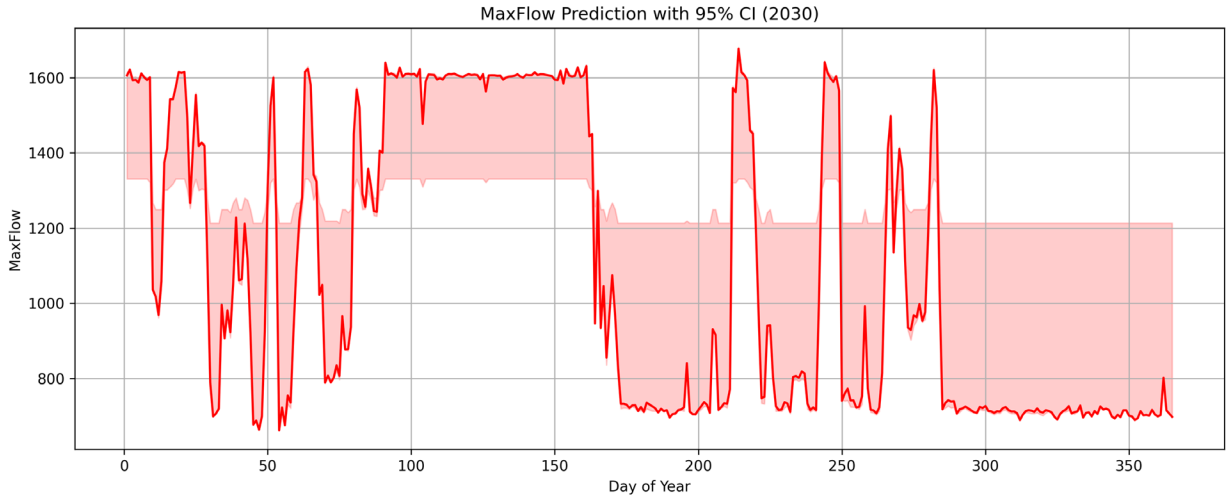


Figure B.9. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and MISO East.

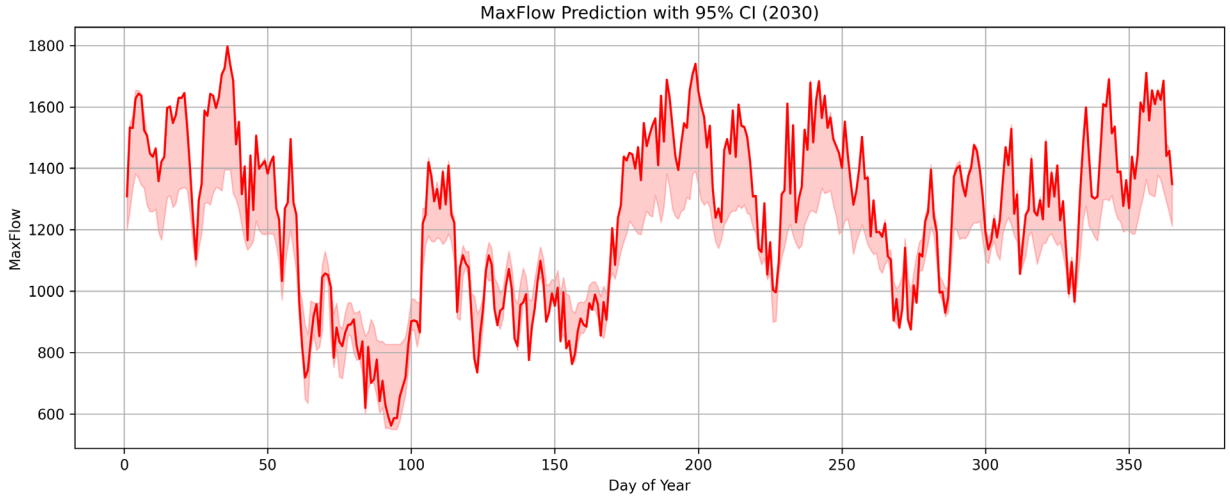


Figure B.10. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and New York.

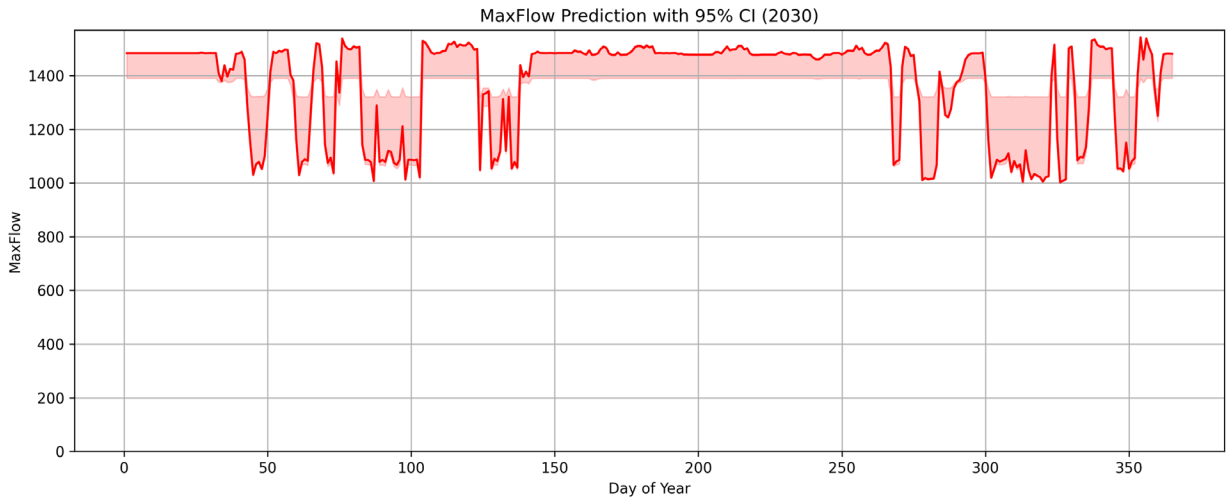


Figure B.11. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Quebec and New York.

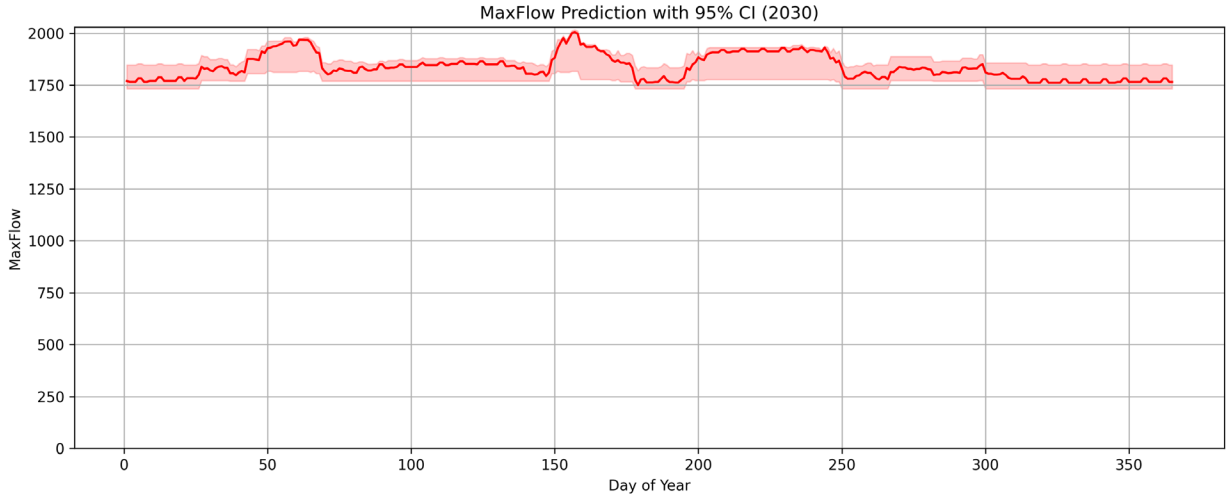


Figure B.12. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Quebec and New England.

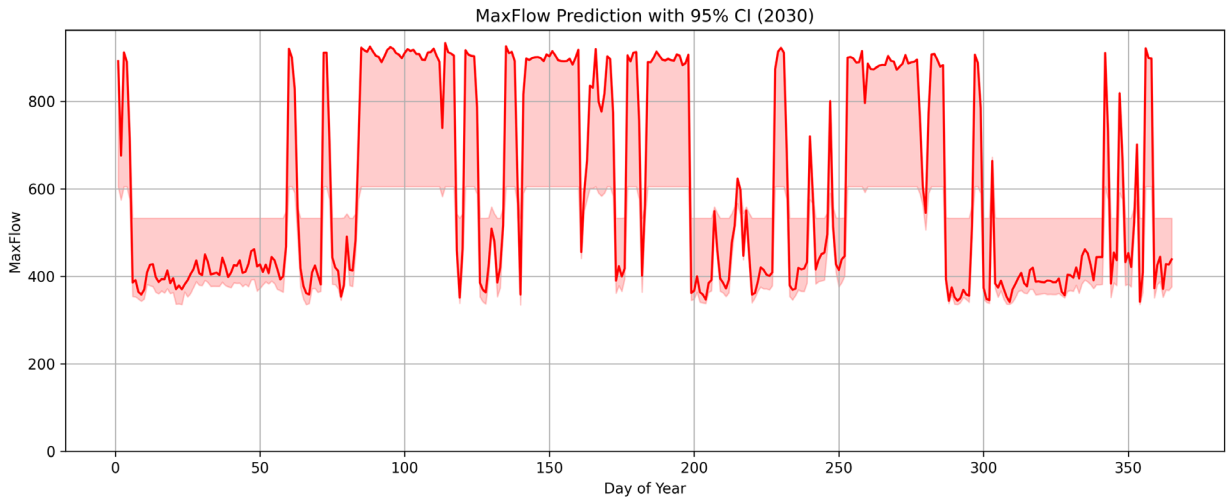


Figure B.13. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between New Brunswick and New England.

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EO 14262

Federal Register / Vol. 90, No. 70 / Monday, April 14, 2025 / Presidential Documents 15521

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

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-7

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

Filed September 5, 2025

Exhibit 97

DOE July 7 Press Release

An official website of the United States government Here's how you know

Department of Energy Releases Report on Evaluating U.S. Grid Reliability and Security

The Department of Energy warns that blackouts could increase by 100 times in 2030 if the U.S. continues to shutter reliable power sources and fails to add additional firm capacity.

Energy.gov

July 7, 2025

4 min

The Department of Energy warns that blackouts could increase by 100 times in 2030 if the U.S. continues to shutter reliable power sources and fails to add additional firm capacity.

WASHINGTON— The U.S. Department of Energy (DOE) today released its Report on Evaluating U.S. Grid Reliability and Security. The report fulfills Section 3(b) of President Trump's Executive Order, *Strengthening The Reliability And Security Of The United States Electric Grid*, by

delivering a uniform methodology to identify at-risk regions and guide Federal reliability interventions.

The analysis reveals that existing generation retirements and delays in adding new firm capacity, driven by the radical green agenda of past administrations, will lead to a surge in power outages and a growing mismatch between electricity demand and supply, particularly from artificial intelligence (AI)-driven data center growth, threatening America's energy security.

"This report affirms what we already know: The United States cannot afford to continue down the unstable and dangerous path of energy subtraction previous leaders pursued, forcing the closure of baseload power sources like coal and natural gas," Secretary Wright said. "In the coming years, America's reindustrialization and the AI race will require a significantly larger supply of around-the-clock, reliable, and uninterrupted power. President Trump's administration is committed to advancing a strategy of energy addition, and supporting all forms of energy that are affordable, reliable, and secure. If we are going to keep the lights on, win the AI race, and keep electricity prices from skyrocketing, the United States must unleash American energy."

Highlights of the Report:

- **The status quo is unsustainable.** DOE's analysis shows that, if current retirement schedules and incremental additions remain unchanged, most regions will face unacceptable reliability risks within five years and the Nation's electrical power grid will be unable to meet expected demand for AI, data centers, manufacturing and industrialization while keeping the cost of living low for all Americans. Staying on the present course would undermine U.S. economic growth, national security, and leadership in emerging technologies.

- **Grid growth must match the pace of AI innovation.** Electricity demand from AI-driven data centers and advanced manufacturing is rising at a record pace. The magnitude and speed of projected load growth cannot be met with existing approaches to load addition and grid management. Radical change is needed to unleash the transformative potential of innovation.
- **With projected load growth, retirements increase the risk of power outages by 100 times in 2030.** Allowing 104 GW of firm generation to retire by 2030—without timely replacement—could lead to significant outages when weather conditions do not accommodate wind and solar generation. Modeling shows annual outage hours could increase from single digits today to more than 800 hours per year. Such a surge would leave millions of households and businesses vulnerable. We must renew a focus on firm generation and continue to reverse radical green ideology in order to address this risk.
- **Planned supply falls short, reliability at risk.** The 104 GW of plant retirements are replaced by 209 GW of new generation by 2030; however, only 22 GW comes from firm baseload generation sources. Even assuming no retirements, the model found outage risk in several regions rises more than 30-fold, proving the queue alone cannot close the dependable-capacity deficit.
- **Old tools won't solve new problems.** Traditional peak-hour tests to evaluate resource adequacy do not sufficiently account for growing dependence on neighboring 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.

DOE's report identifies regions most vulnerable to outages under various weather and retirement scenarios and offers capacity targets needed to restore acceptable reliability. The methodology also informs the

potential use of DOE's emergency authority under Section 202(c) of the Federal Power Act.

Click here for a fact sheet on the report.

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Exhibit to
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Public Interest Organizations

Filed September 5, 2025

Exhibit 98

Eddystone August Order

Department of Energy
Washington, DC 20585

Order No. 202-25-8

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 the PJM Interconnection, L.L.C. (PJM) region due to a shortage of facilities for the generation of electric energy, resource adequacy concerns, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

Order No. 202-25-4

The Eddystone Generating Station is a power plant owned by Constellation Energy Corporation (Constellation Energy) and located in Eddystone, PA. Units 3 and 4 (Eddystone Units), each with 380 MW of generation capacity, are subcritical steam boiler-turbine generator units that can run on either natural gas or oil, depending on market conditions. The Eddystone Units were initially scheduled for retirement on May 31, 2025.

Order No. 202-25-4, issued pursuant to FPA section 202(c), required that the Eddystone Units remain in operation for 90 days, until August 28, 2025. That order was based on my determination that emergency conditions existed in the PJM region. I explained that there was a potential shortage of electric energy and shortage of facilities for generation of electric energy. I stated that the potential loss of power to homes and local businesses presents a risk to public health and safety. I determined that the operational availability and economic dispatch of the Eddystone Units is necessary to best meet the emergency and serve the public interest. My determination was based on a number of different facts.

First, in congressional testimony, PJM's president and CEO recently stated that its system faces a "growing resource adequacy concern" due to load growth, the retirement of dispatchable resources, and other factors.[1] He stated that, through 2030, PJM anticipates reliability risk from increasing electricity demand, generator retirement outpacing new resource construction, and characteristics of resources in PJM's interconnection queue.[2] Upcoming retirements, including the planned retirement of the Eddystone Units, would exacerbate these resource adequacy issues.

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[1] *Keeping the Lights On: Examining the State of Regional Reliability,* Before the *H. Comm. on Energy and Com., S. Comm. on* Energy, 119th Cong. (Mar. 25, 2025) (testimony of Mr. Manu Asthana, President and CEO of PJM Interconnection) (Asthana Test.) at 4-5, available at https://www.congress.gov/119/meeting/house/118040/witnesses/HHRG-119-IF03-Wstate-AsthanaM-20250325.pdf.
[2] *Id.*

Second, PJM indicated that resource constraints could exist within its service territory under peak load conditions, stating that "available generation capacity may fall short of required reserves in an extreme planning scenario."[3] In its February 2023 assessment "*Energy Transition in PJM: Resource Retirements, Replacements & Risks* (Four Rs Report)," PJM highlighted increasing reliability risks in the coming years due to the "potential timing mismatch between resource retirements, load growth and the pace of new generation entry" under "low new entry" scenarios for renewable generation.[4]

Third, in December 2024, PJM filed revisions with the Federal Energy Regulatory Commission (FERC) to Part VII of its Open Access Transmission Tariff, known as the Reliability Resource Initiative (RRI), to address near-term resource adequacy concerns. In a February 2025 order, FERC accepted the revisions and found "the possibility of a resource adequacy shortfall driven by significant load growth, premature retirements, and delayed new entry."[5]

Continuing Emergency Conditions

The emergency conditions that led to the issuance of Order No. 202-25-4 continue, both in the near and long term. The summer season has not yet ended, and the production of electricity from the Eddystone Units will continue to be critical to maintaining reliability in PJM this summer. This need is evidenced by the fact that the Eddystone Units were called on by PJM to generate electricity during heat waves that hit the region in June and July.

According to U.S. Environmental Protection Agency data, the Eddystone Units generated over 17,000 MWhs during the month of June.[6] Further, over a period of hot weather from June 23 to June 26, Unit 3 ran for a total of 65 hours and Unit 4 ran for a total of 59 hours.[7] During a hot weather period from July 28 to July 30, Unit 3 ran for 39 hours and Unit 4 ran 8 hours.[8]

Over the course of the summer, PJM has issued Hot Weather Alerts and/or Maximum Generation Alerts (EEA 1) covering a total of 20 days, including days in June, July, and August.[9] The hot weather may continue in the near term, as the Seasonal Outlook released by the National Oceanic and Atmospheric Administration (NOAA) on August 21, 2025, projects between a 40%

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[3] *PJM Summer Outlook 2025: Adequate Resources Available for Summer Amid Growing* Risk, PJM Interconnection, L.L.C. (May 9, 2025), https://insidelines.pjm.com/pjm-summer-outlook-2025-adequate-resources-available-for-summer-amid-growing-risk/.

[4] *Energy Transition in PJM: Resource Retirements, Replacements & Risks,* PJM (Four Rs Report) at 1, (Feb. 24, 2023), https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx.

[5] *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084 (2025).

[6] *See Custom Data Download, EPA CAMPD* (Clean Air Markets Program Data), https://campd.epa.gov/data/custom-data-download (search criteria Emissions >> Monthly >> Unit (default) >>Apply >>"2025" and "June" (search date Aug. 22, 2025).

[7] *See PJM daily reports to DOE under Order No. 202-25-4, June 24-27, 2025.*

[8] *See PJM daily reports to DOE under Order No. 202-25-4, July 29-31, 2025.*

[9] *See* PJM Emergency Procedures Postings for the period between June 1 and August 31, *Emergency Procedures*, https://emergencyprocedures.pjm.com/ep/pages/dashboard.jsf (search range set to: effective from 06/01/2025 until 08/31/2025).

and 60% probability of above-normal temperatures in the Mid-Atlantic region, which includes the PJM region, over the next three calendar months.[10]

The evidence also indicates that there is a potential longer term resource adequacy emergency in the PJM region.

In its news release expressing support for Order No. 202-25-4, PJM explained that it has "repeatedly documented and voiced its concerns over the growing risk of a supply and demand imbalance driven by the confluence of generator retirements and demand growth. Such an imbalance could have serious ramifications for reliability and affordability for consumers."[11]

PJM has indeed voiced these concerns for years. In its February 2023 Four Rs Report, PJM cautioned that 40 GW of thermal generation are at risk of retirement by 2030.[12] PJM also noted that, while there were then 290 GW of renewable generation capacity in the PJM interconnection queue, historically, the rate of completion for renewable projects is approximately five percent.[13] PJM determined that the pace of new capacity additions "would be insufficient to keep up with expected retirements and demand growth by 2030."[14] PJM estimated that, depending on the pace of new capacity additions, reserve margin erosion would occur between 2026 and 2028.

More recently, in its December 2024 RRI filing with FERC, PJM stated that "[c]oncerns about resource adequacy . . . have only increased since the Four Rs Report . . . ."[15] PJM warned that its "resource adequacy concerns are increasing at an extraordinary pace."[16] PJM went on to explain, its "resource adequacy concerns are driven in large part by significant load growth caused by, among other things, large data centers" and that its preliminary analysis shows "substantial increases [in load additions] since the 2024 forecast" for both the summer and winter seasons.[17] According to PJM, "load growth and generator retirements are significantly outpacing the entry of new generation in the PJM Region with this trend expected to continue unabated based on all available evidence."[18] Although the RRI process will help expedite the construction of needed

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[10] *Seasonal Outlook*, NOAA Climate Prediction Ctr., (Aug. 21, 2025), https://www.cpc.ncep.noaa.gov/products/predictions/long_range/seasonal.php?lead=1.
[11] *PJM Statement on the U.S. Department of Energy 202(c) Order of May 30*, PJM (May 31, 2025), https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/2025-releases/20250531-doe-202c-statement-to-defer-retirements-of-certain-generators.pdf.
[12] Four Rs Report, *supra* n. 4, at 2.
[13] *Id.*
[14] *Id.* at 16, Table 1.
[15] *PJM Interconnection, L.L.C.*, FERC Docket No. ER25-712, Tariff Revisions for Reliability Resource Initiative at 10 (Dec. 13, 2024).
[16] *Id.*
[17] *Id.* at 10-11. *See also id.* at 13 ("the exponential load growth resulting from development of new data centers and the intense energy needs of Artificial Intelligence technology overshadows any relaxation in the pace of fossil fuel generation retirements…").
[18] *Id.* at 14.

new capacity, it is unlikely to result in the addition of any new generation capacity in the next few years.[19]

In support of the RRI filing, PJM submitted an affidavit from Donald Bielak, PJM's Director, Interconnection Planning. Mr. Bielak characterized the increase in forecasted load growth throughout PJM as "extraordinary" and "unprecedented," stating that it "could not have been foreseen as recently as a year ago."[20] Mr. Bielak expressed the opinion that the "rapid" retirement of thermal generation resources, "extreme" forecasted load growth, and "delays in new generation resources achieving commercial operation," would adversely affect resource adequacy throughout PJM's electricity grid.[21]

The North American Electric Reliability Corporation (NERC) has raised similar concerns. According to NERC's 2024 Long Term Reliability Assessment, "PJM could face future resource adequacy challenges, impacting system reliability and PJM's ability to serve load."[22] NERC assessed the PJM region at an elevated risk starting in 2026,[23] explaining that "[r]esource additions are not keeping up with generator retirements and demand growth."[24] NERC stated that the loss-of-load hour (LOLH) and expected unserved energy (EUE) risks are concentrated in the winter months (especially January), in both 2026 and 2028.[25]

Order 202-25-4 was preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. Specifically, in Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[26] President Trump likewise recognized, in Executive Order 14156, "Declaring a National Energy Emergency," that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[27] The Executive Order adds: "Hostile state and non-state foreign actors have targeted our domestic energy infrastructure,

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[19] *See id.*, Attachment C (Affidavit of Mr. Donald Bielak) ¶ 18-19 (explaining that projects studied in Transition Cycle #2, which includes RRI projects, "could be constructed and in commercial operation by the 2029/30 Delivery Year or sooner.").
[20] *Id*. at 12.
[21] *Id*. at 7.
[22] *2024 Long-Term Reliability Assessment*, North American Electric Reliability Corporation at 92 (Dec. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf at 92.
[23] *Id.* at 4.
[24] *Id.* at 7.
[25] *Id.* at 91-92.
[26] Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (Strengthening the Reliability and Security of the United States Electric Grid), https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliabilityand-security-of-the-united-states-electric-grid/.
[27] Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (Declaring a National Energy Emergency), https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/.

weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[28]

The Department of Energy's (Department) July 2025 Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid, issued pursuant to the President's directive in Executive Order 14262, details the myriad challenges affecting the Nation's energy outlook. It concludes, "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."[29] The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth. For example, PPL Electric Utilities has 11.7 GW of advanced data center requests in Pennsylvania through to 2030.[30] As of December 2024, Dominion Energy has 40.2 GW of contracted data center capacity, which is an 18.2 GW increase over the amount from July 2024, an approximately 88% increase.[31] Regarding the PJM region, the Department's analysis performed this year in collaboration with the national labs modeled the effects of approximately 25 GW of load growth in PJM, of which 15 GW came from data centers, as well as approximately 17 GW of announced coal, gas, and oil generation retirements.[32] Under these assumptions, the model estimated approximately 430.3 loss of load hours in an average weather year. Under worst weather year assumptions, the model estimated 1,052 loss of load hours and a max unserved load hours of approximately 21.335 GW.[33]

Grid operators, including PJM, have likewise acknowledged the Nation's current energy crisis. For instance, during a March 25, 2025, hearing before the United States House of Representatives Committee on Energy and Commerce, Manu Asthana, President and CEO, PJM, testified that there was a "growing resource adequacy concern . . . impacting a significant part of our country."[34] Mr. Asthana explained that the "rate of electricity demand is anticipated to increase significantly in the future due to development of large data centers in the PJM service Area . . . [and] increases in demand coming from the transportation and heating sectors and from industrial growth."[35] Mr. Asthana noted that, "though various reforms instituted by PJM had succeeded in bringing new generation online and preventing the retirement of existing units, supply conditions within PJM are still tightening." Therefore, Mr. Asthana stated that PJM

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[28] *Id.*

[29] *See also* Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid, U.S. Department of Energy (July 2025), at 1, https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[30] *See PPL Corporation Q2 2025 Investor Update*, PPLC Corporation (July 31, 2025) at 7, https://filecache.investorroom.com/mr5ir_pplweb2/1245/PPL_2025_Q2_Investor_Update_vFINAL.pdf

[31] *See* Dominion Energy Virginia, Q4 2024 Earnings Call (Feb. 12, 2025), at 18, https://s2.q4cdn.com/510812146/files/doc_financials/2024/q4/2025-02-12-DE-IR-4Q-2024-earnings-call-slides-vTCII.pdf.

[32] *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, U.S. Department of Energy (July 2025), at 28, https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[33] *Id.* at 27.

[34] Asthana Test. at 4.

[35] *Id*.

"encourage[s] all generation owners who have signaled an intent to retire their units to reconsider their decision to support resource adequacy and grid reliability."[36]

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of the Department of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," then the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."[37] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of the Eddystone Units when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

Such is the case here. As described above, the emergency conditions resulting from increasing demand and accelerated retirements of generation facilities supporting the issuance of Order No. 202-25-4 will continue in the near term and are also likely to continue in subsequent years. This could lead to the potential loss of power to homes and local businesses in the areas that may be affected by curtailments or outages, presenting a risk to public health and safety. Given the responsibility of PJM to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of the Eddystone Units is necessary to best meet the emergency and serve the public interest under FPA section 202(c).

To ensure the Eddystone Units will be available if needed to address emergency conditions, the Eddystone Units shall remain in operation until November 26, 2025.[38]

Based on my determination of an emergency set forth above, I hereby order:

A. From 5:03PM EDT on August 28, 2025, PJM and Constellation Energy shall take all measures necessary to ensure that the Eddystone Units are available to operate. For the duration of this Order, PJM is directed to take every step to employ economic dispatch of the Eddystone Units to minimize cost to ratepayers. Constellation Energy is directed to comply with all orders from PJM related to the availability and dispatch of the Eddystone Units.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by PJM pursuant to paragraph A. PJM shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Eddystone Units has operated in

[36] *Id*. at 10.
[37] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b) (2018).
[38] 16 U.S.C. § 824a(c)(4).

compliance with the allowances contained in this Order.

C. All operation of the Eddystone Units must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. By September 12, 2025, PJM is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Eddystone Units consistent with this Order. PJM 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. Constellation Energy is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers to effectuate this Order. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

F. This Order shall not preclude the need for the Eddystone Units to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, the Eddystone Units shall not be considered capacity resources.

H. This Order shall be effective from 5:03 PM Eastern Daylight Time (EDT) on August 28, 2025, and shall expire at 00:00 EST on November 26, 2025, with the exception of applicable compliance obligations in paragraph D.

I. Issued in Washington, D.C., at 7:11 PM Eastern Daylight Time on this 27th day of August 2025.

Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang

Pennsylvania Public Utility Commissioners
Chairman Stephen M. DeFrank
Vice Chair Kimberly M. Barrow
Commissioner Kathryn L. Zerfuss
Commissioner John F. Coleman, Jr.
Commissioner Ralph V. Yanora

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-7

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

Filed September 5, 2025

Exhibit 99

PIOs' RFR of July Resource Adequacy Report

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

In re	)
Resource Adequacy Report	)
Evaluating the Reliability and Security	)
Of the United States Electric Grid	)
	)

Motion to Intervene and Request for Rehearing of
Natural Resources Defense Council, the Ecology Center, Environmental Defense Fund, Environmental Law and Policy Center, Public Citizen, Sierra Club, and Vote Solar

I. INTRODUCTION

Pursuant to section 313 of the Federal Power Act ("the Act"), 16 U.S.C. § 825*l*, Natural Resources Defense Council, the Ecology Center, Environmental Defense Fund, Environmental Law and Policy Center, Public Citizen, Sierra Club, and Vote Solar ("Public Interest Organizations") hereby move, to the extent necessary, to intervene and request rehearing of the Department of Energy's ("Department" or "DOE") "Resource Adequacy Report: Evaluating the Reliability and Security of the United States" ("RAR").[1] The Department issued the RAR in response to Executive Order 14,262 *Strengthening the Reliability and Security of the United States Electric Grid,* April 8, 2025 ("Grid EO"),[2] and claims that the RAR is a "uniform methodology to identify at-risk region(s) and guide reliability interventions" as directed by the Grid EO.[3] But the Department simultaneously disclaims the utility of the RAR to guide interventions uniformly, acknowledging on the very first page that the various "entities responsible for the maintenance and operation of the grid" have information "that could further enhance the robustness of reliability decisions" in their parts of the grid.[4]

The flaws in the RAR continue. The Department overstates assumptions about demand growth and likely retirements while understating likely new entry, building into the RAR an inherent bias toward a finding of inadequate resource adequacy. The Department also departs from best practices by using a

[1] July 7, 2025, https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf (attached as Ex. 1) (hereinafter, the "RAR").

[2] 90 Fed. Reg. 15521 (Apr. 8, 2025) (hereinafter "Grid EO").

[3] *Id.* at vi.

[4] *Id.* at i.

deterministic approach, which fails to account for necessary uncertainties and demonstrates that the RAR's findings should not be taken as conclusive or form the basis for further extraordinary actions. And on some critical aspects of the RAR analysis, the Department simply fails to explain its own methodology; while the Department describes two thresholds at which the RAR projects outages will occur, it fails to explain when it applies the standard threshold and when it applies the elevated one. These flaws render any reliance on the RAR to "guide reliability interventions" arbitrary and capricious.

While the Department acknowledges that the RAR is unsuitable to guide reliability interventions uniformly and provided no notice or opportunity to comment, the Department nevertheless does not clarify how it will use the RAR, creating confusion as to whether the RAR, in conjunction with the Grid EO, is intended to function as a final rule. Public Interest Organizations believe that the RAR should not be used as the basis for future action by the Department. We submit this request for rehearing in an abundance of caution, to the extent the Department later argues that any of these issues must have been raised in a request for rehearing within 30 days of the publication of the RAR, 16 U.S.C. § 825*l*. We also reserve our right to argue in later proceedings that 16 U.S.C. § 825*l* does not apply.

In sum, the RAR is a poorly crafted solution in search of a problem; there is no "energy emergency" and the regulatory bodies who actually possess authority to ensure resource adequacy are doing their jobs. Consequently, the RAR serves no useful purpose and should simply be withdrawn. By DOE's own admission, the RAR cannot reasonably be relied on to guide DOE interventions, nor, given the false premise and multiple mistaken assumptions, does it provide any value even as a purely informational report. On the contrary, it will only cause confusion for grid operators, energy providers, and members of the public. In the alternative, the Department should not use the RAR as support for any reliability intervention or other action until and unless it (1) provides notice of the statutory authority under which DOE issued the RAR and publishes all data underlying the RAR, (2) explains in detail the specific uses for the methodology, and (3) allows interested parties to comment on the RAR before finalizing it.

II. STATEMENT OF ISSUES

1. The Department intrudes on Federal Energy Regulatory Commission ("FERC" or "the Commission") and state authority. 16 U.S.C. §§ 824a(c),824o-1; 42 U.S.C. § 7113.
2. The RAR's findings, even if accurate, do not demonstrate any emergency allowing the Department to compel generation under the Federal Power Act. 16 U.S.C. § 824a(c); S. Rep. No. 74-621 (1935); 10 C.F.R. § 205.371; 10 C.F.R. § 205.375; 46 Fed. Reg. 39,985.

3. The RAR is analytically flawed and does not rely upon substantial evidence. 16 U.S.C. 824a(a); 16 U.S.C. § 824o(a)(3).
4. The Department cannot use the RAR as a "uniform methodology" without giving notice and taking public comment. 5 U.S.C. §§ 552, 553; 10 C.F.R. §§ 205.371; 205.373.
5. The Department cannot use the RAR as a "uniform methodology" without following National Environmental Policy Act procedural requirements. 42 U.S.C. § 4332(C).

III. INTERVENTION

Each of the Public Interest Organizations has interests that may be directly and substantially affected by the use of this RAR as a "uniform methodology" to guide "reliability interventions," including the issuance of Emergency Orders under Section 202(c) of the Federal Power Act, 16 U.S.C. § 824a(c).[5] To the extent that the RAR is determined to be an Order or Rule, each party may intervene in this proceeding.[6] And to the extent the Department treats the RAR as binding and uses it to guide reliability interventions, each of the Public Interest Organizations and their members will suffer concrete injuries that are redressable through rehearing.[7] Each organization is therefore aggrieved if the RAR is a "uniform methodology" for use in guiding interventions, as the Department purports, and each organization may properly apply for rehearing, assuming without conceding that the rehearing procedures apply.[8]

A. Natural Resources Defense Council

Natural Resources Defense Council ("NRDC") is a national non-profit membership organization whose mission includes ensuring the rights of all people to clean air, clean water, and healthy communities. NRDC has a longstanding organizational commitment to protect the interests of its members and to reducing pollution caused by fossil fuel fired power plants. NRDC works to achieve clean

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[5] *See* RAR, Ex. 1 at iv.

[6] *See* U.S. Dep't of Energy, DOE 202(c) Order Rehearing Procedures, https://www.energy.gov/ceser/doe-202c-order-rehearing-procedures (last visited June 18, 2025) (archived version attached as Ex. 2) (hereinafter "DOE Rehearing Procedures"). This website was altered after June 18, 2025, and the procedures were removed. *Compare* https://web.archive.org/web/20250604093213/https://www.energy.gov/ceser/doe-202c-order-rehearing-procedures with the current website. *See also* Email from Lot Cooke, U.S. Dep't of Energy to Linda Alle-Murphy Re: Rehearing procedures for DOE Order No. 202-05-3 (December 30, 2005) (recommending that "a party seeking rehearing can look for procedural guidance to [Federal Energy Regulatory Commission's ("FERC")] Rules of Practice and Procedure, 18 CFR Part 385.") (attached as Ex. 3).

[7] *See, e.g. Alcoa Inc. v. FERC*, 564 F.3d 1342, 1346 (D.C. Cir. 2009).

[8] *See* 16 U.S.C. § 825*l*(a); *Wabash Valley Power Ass'n, Inc. v. FERC*, 268 F.3d 1105, 1112-13 (D.C. Cir. 2001); *NextEra Energy Res. v. ISO New Eng., Inc.*, 157 FERC ¶ 61,059, at P 5 (2016).

energy solutions that will lower consumer energy bills, meet greenhouse gas emission reduction goals, accelerate the use of energy efficiency and renewable energy, and ensure that clean energy is affordable and accessible to all. NRDC has hundreds of thousands of members across the United States. These NRDC members are harmed by orders to operate fossil fuel powered generation past planned retirement dates because continued operation will subject NRDC members to air and water pollution in the areas where they live, work, and recreate. NRDC members are also exposed to the noise and visual impacts of these facilities' operations. In addition, NRDC members are ratepayers in regions who will be subject to higher electric bills as a result of new or renewed 202(c) Orders issued as a result of the RAR. For that reason, NRDC filed requests for rehearing of DOE's 202(c) orders issued to the J.H. Campbell and Eddystone plants, the latter of which explicitly stated that it would be reexamined following publication of the methodology. NRDC has five U.S. offices that also will be subject to higher electric bills as a result of "reliability interventions" undertaken as a result of the RAR's "uniform methodology." Moreover, NRDC has a sustainable operations plan with a goal of reducing net creation of greenhouse gas emissions derived from building operational activity to zero. NRDC and its members therefore have a strong interest in promoting actions that displace less cost-effective fossil generation with more cost-effective clean energy.

B. The Ecology Center

The Ecology Center is a Michigan-based non-profit organization headquartered in Ann Arbor, Michigan, with additional offices in Detroit, Michigan. Ecology Center is a public interest organization with more than 50 years of experience advocating for clean energy production, healthy communities, environmental justice, and a sustainable future. Ecology Center works at the local, state, and federal level. Its programs address systemic sources of poor health and environmental degradation through unique partnerships with environmental health and environmental advocates. Ecology Center has over 6,000 members and supporters, that live, use electricity, and pay electric bills in Michigan and could be subject to higher electric bills as a result of new or renewed 202(c) Orders issued as a result of the RAR. In addition, Ecology Center members are harmed by orders to operate fossil fuel powered generation past planned retirement dates because continued operation will subject Ecology Center members to air and water pollution in the areas where they live, work, and recreate.

C. Environmental Defense Fund

The Environmental Defense Fund ("EDF") is a non-profit membership organization with hundreds of thousands of members nationwide whose mission is to build a vital Earth for everyone by preserving the natural systems on which all life depends. Guided by expertise in science, economics, law, and business partnerships, EDF seeks practical and lasting solutions to address environmental problems and protect human health, including in particular by addressing pollution from the power sector. On behalf of its members, EDF works with partners across

the private and public sectors to engage in utility regulatory forums at the federal level and throughout the United States to advocate for policies that will create an affordable, reliable, and low pollution energy system. Recent 202(c) Orders issued by the DOE have harmed members of EDF by causing increases in pollution, which impact the health of people and nature, and in energy costs. EDF has submitted requests for rehearing regarding the DOE Orders related to the J.H. Campbell and Eddystone power plants and a Petition for Review regarding the DOE Order regarding the J.H. Campbell plant. Further 202(c) Orders issued as a result of the RAR, including extensions of the J.H. Campbell and Eddystone orders and orders directed at other generators, will result in further pollution and cost impacts that will harm EDF members.

D. Environmental Law and Policy Center

Environmental Law and Policy Center ("ELPC") is a not-for-profit environmental organization with members, contributors, and offices throughout the Midwest. Among other things, ELPC advocates before state public service commissions and the Federal Energy Regulatory Commission for clean, reliable energy generation in order to reduce ratepayer costs and improve environmental outcomes. ELPC members in the Midwest live, work, and recreate near power plants that burn coal or other fossil fuels and are directly impacted by their pollutants. In addition, ELPC members are ratepayers in regions who could be subject to higher electric bills as a result of new or renewed 202(c) Orders issued as a result of the RAR. ELPC and its members could be subject to higher electric bills and impacted by additional pollution as a result of "reliability interventions" undertaken as a result of the RAR's "uniform methodology." ELPC has a longstanding organizational commitment to protect the interests of its members, to reduce pollution caused by fossil fuel-fired power plants, and to promote clean, reliable energy generation.

E. Public Citizen

Public Citizen, Inc. hereby intervenes in these proceedings. Public Citizen, Inc. is an active intervenor and participant before the Federal Energy Regulatory Commission in Federal Power Act proceedings, as well as before the U.S. Department of Energy in both electricity export and natural gas export dockets to ensure just and reasonable rates and that utilities' operations are consistent with the public interest. Established in 1971, Public Citizen, Inc. is a national, not-for-profit, non-partisan, research and advocacy organization representing the interests of American household consumers. Public Citizen has members in all 50 states and represents the interests of consumers, not represented by any other party in this proceeding. Financial details about our organization are on our website: www.citizen.org/about/annual-report/.

F. Sierra Club

Sierra Club is a national environmental non-profit whose purpose is to explore, enjoy, and protect the wild places of the earth; to practice and promote the responsible use of the earth's ecosystems and resources; to educate and enlist humanity to protect and restore the quality of the natural and human environment; and to use all lawful means to carry out these objectives. To those ends, the Sierra Club and its members have worked to limit pollution caused by fossil-fuel-fired power plants through public education and advocacy at the local, state, and federal level. Sierra Club represents over 640,000 members nationwide, many of whom reside and recreate in the regions in which the RAR purports to identify resource shortfalls requiring the continued operation of coal- and gas-fired generation. Sierra Club members in those areas would be harmed by the pollution and the increased utility rates caused by any such continued operation.

G. Vote Solar

Vote Solar is an independent 501(c)(3) non-profit working to re-power the U.S. with clean energy by making solar power more accessible and affordable through effective policy advocacy. In over half of the country, Vote Solar seeks to promote the development of solar at every scale, from distributed rooftop solar to large utility-scale plants. Vote Solar has over 90,000 members nationally. Vote Solar members are ratepayers in regions who could be subject to higher electric bills as a result of new or renewed 202(c) Orders issued as a result of the RAR. Vote Solar is not a trade organization, nor does it have corporate members. Vote Solar is committed to promoting clean, renewable energy and transitioning away from coal generation.

IV. BACKGROUND

A. Executive Orders

The genesis of the RAR lies in the President's unsupported day one declaration of a national energy emergency: *Declaring a National Energy Emergency* ("Energy Emergency EO").[9] That declaration's lack of factual underpinning was highlighted in a recent report by DOE's independent statistics and analysis arm, the Energy Information Administration ("EIA"). The EIA report highlights how U.S. energy production and exports are currently at an all-time high.[10] Nonetheless, the Energy Emergency EO was cited as a basis for the

[9] Exec. Order No. 14,156, 90 Fed. Reg. 8433 (January 20, 2025) (hereinafter "Energy Emergency EO") (attached as Ex. 4). *See* also RAR, Ex. 1 at vi (explaining that the Grid EO "builds on" the Energy Emergency EO).

[10] *See* U.S. EIA, *U.S. primary energy production, consumption, and exports increased in 2024* (June 20, 2025), https://www.eia.gov/todayinenergy/detail.php?id=65524.

President's follow-up grid-specific executive order, the Grid EO, that led to DOE's publication of the RAR.[11]

The Grid EO directed DOE to take three steps to address the President's assertion that there may be lack of grid reliability in the future, including: 1) to streamline the processes to issue orders pursuant to Federal Power Act Section 202(c);[12] 2) to develop a reserve margin assessment methodology and use it to identify at risk regions and critical energy resources within those regions and to publish that methodology within 90-days of the Grid EO;[13] and 3) to establish a protocol for identifying critical generating resources and taking action to prevent retirement or conversion of the fuel source of such resources.[14]

Notably, the Grid EO was issued in conjunction with a series of actions by President Trump and DOE designed explicitly to prop up the coal and gas industries, including: 1) Executive Order 14,261, *Reinvigorating America's Beautiful Clean Coal Industry,*[15] which seeks to restart coal leasing and expand coal mining on federal lands, in addition to making these processes easier by offering loans and streamlining permitting;[16] 2) a Presidential Proclamation entitled *Regulatory Relief for Certain Stationary Sources to Promote American Energy* that exempts coal plants from complying with the U.S. Environmental Protection Agency's updated Mercury and Air Toxics Standards;[17] and 3) Executive Order 14,260, *Protecting American Energy from State Overreach*,[18] which directs the U.S.

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[11] Nor does the Energy Emergency EO supply legal support for the Grid EO. Under the National Emergencies Act, 50 U.S.C. § 1631, a declaration of national emergency does not authorize the exercise of emergency powers "unless and until the President specifies the provisions of law under which he proposes that he, or other officers will act." But as Congress made clear, the statute "is not intended to enlarge or add to Executive power" such as authority under Section 202(c), only to "establish clear procedures and safeguards for the exercise by the President of emergency powers conferred on him by other statutes." S. Rep. No. 94-1168, 3 (1976).

[12] Grid EO Section 3(a).

[13] *Id.* Section 3(b).

[14] *Id.* Section 3(c).

[15] *See* Exec. Order No. 14,261, 90 Fed. Reg. 15,517 (Apr. 8, 2025).

[16] DOE simultaneously announced several initiatives to subsidize the coal industry, including loan guarantees for coal-fired power plant projects. Dep't of Energy, *Energy Department Acts to Unleash American Coal by Strengthening Coal Technology and Securing Critical Supply Chains* (Apr. 8, 2025), https://www.energy.gov/articles/energy-department-acts-unleash-american-coal-strengthening-coal-technology-and-securing.

[17] Proclamation No. 10914, 90 Fed. Reg. 16777 (Apr. 8, 2025).

[18] Exec. Order No. 14,260, 90 Fed. Reg. 15513 (Apr. 8, 2025).

Department of Justice to take action to block states' exercises of their police powers to protect their residents from pollution caused by coal and fossil-fuel sources.[19]

B. RAR

On July 7, 2025, DOE published the RAR on its website. The RAR includes a deterministic analysis of the resource adequacy of the current electric system and three 2030 cases: (1) the Plant Closure case includes 104 GW of coal and gas retirements plus 100% of NERC's Tier 1 additions; (2) the No Plant Closures case includes no retirements but 100% of NERC's Tier 1 additions; and (3) the Required Build case begins with the Plant Closures scenario and projects what additional added perfect capacity would be needed to meet the RAR's determined reliability standards.[20] Each of the three 2030 scenarios assume 50 GW of load growth from data centers and an additional 51 GW of load growth from other sources.[21] The Department finds in the RAR that, under the current system, only ERCOT fails to achieve DOE's selected resource adequacy targets,[22] but that, based on the methodology used to forecast the 2030 scenarios, there will be broader resource adequacy issues in 2030.[23] And, notwithstanding the RAR's upfront acknowledgement that the analysis used "could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level,"[24] the Department proceeds to make broad declarations of future need based on its findings in the RAR.[25]

DOE explained that the RAR was being issued pursuant to the Grid EO. The RAR incorporates a full copy of the Grid EO and explains that "[t]his report serves as DOE's response to [the Grid EO's] Section 3(b) … by delivering the required uniform methodology to identify at-risk region(s) and guide reliability

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[19] These actions mimic President Trump's failed efforts to prop up the coal industry during his first term, including DOE's proposed rule, soundly rejected by FERC, that would have provided assured cost recovery (including a return on equity) for coal and nuclear plants (*see* 162 FERC ¶ 61,012), and the President's unfulfilled directive that DOE use Section 202(c) and the Defense Production Act to block closure of uneconomic coal plants while requiring grid operators to bear the costs. *See* Draft Memorandum (May 29, 2018), https://embed.documentcloud.org/documents/4491203-Grid-Memo/.

[20] RAR, Ex. 1 at 4-5.

[21] *Id.* at 2-3, 15-17.

[22] *Id.* at 7.

[23] *Id.* at 6-9.

[24] *Id.* at i.

[25] *Id.* at 1-2. *See also*, DOE Fact Sheet, https://www.energy.gov/sites/default/files/2025-07/DOE_Fact_Sheet_Grid_Report_July_2025.pdf; DOE Press Release, https://www.energy.gov/articles/department-energy-releases-report-evaluating-us-grid-reliability-and-security.

interventions."[26] DOE's statement that it intends to use the methodology "to guide reliability interventions" and that DOE will continue to use the RAR "on a regular basis to ensure its usefulness for effective action among industry and government decision-makers across the United States" suggests that the RAR may be intended to also serve as the protocol called for by Section 3(c) of the Grid EO.[27] But the RAR fails to clarify this, or, if the RAR does not also serve as DOE's response to Section 3(c), whether a protocol has been or will be developed, or whether any protocol will be made public. The RAR does not include any discussion of Section 3(a) of the Grid EO. To the extent that the Department addressed that portion of the Grid EO's directions, it has not made any process changes public. On the contrary, the Department has made its processes under Section 202(c) even less transparent by removing the existing process guidance from the DOE website.[28]

Notwithstanding the statement in the RAR that DOE intends to use the "methodology to identify at-risk region(s) and guide reliability interventions," e.g., Section 202(c) Orders,[29] other portions of the RAR make clear that it can't and shouldn't be used as a basis for interventions, specifically not issuance of 202(c) Orders. First and foremost, the reliability projections in the RAR focus on conditions five years from now and concede that there are not current grid conditions that fit within Section 202(c)'s definition of an "emergency." Second, the Department candidly concedes the RAR's lack of robustness: "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."[30]

C. Section 202(c) Orders

Section 202(c) of the Federal Power Act allows the Secretary of Energy, in certain emergency situations, to require by order temporary connections of facilities, and generation, delivery, interchange, or transmission of electricity as the Secretary

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[26] RAR, Ex. 1 at vi.

[27] *Id.*

[28] *Compare* https://web.archive.org/web/20250604093213/https://www.energy.gov/ceser/doe-202c-order-rehearing-procedures with the current website.

[29] *See* 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 ("The methodology also informs the potential use of DOE's emergency authority under Section 202(c) of the Federal Power Act.").

[30] RAR, Ex. 1 at i.

determines will best meet the emergency and serve the public interest. Section 202(c) has an important purpose: to mitigate electricity shortages caused by war, drought, and other emergencies. In granting DOE the authority that Section 202(c) provides, Congress considered the severe societal consequences of blackouts and determined that avoiding those consequences justified allowing DOE to act without notice and to require operations that override environmental laws. But Congress was also very careful to narrowly limit DOE's use of that authority, as the title of the provision makes clear, to "temporary" "emergency" situations.[31] And while the statute doesn't define "emergency," DOE's regulations include a lengthy definition which reinforces the key element in the statute: 202(c) orders are for situations that are sudden and unexpected, not for longer term grid management.[32]

1. DOE's Past Use of 202(c) Orders

The Department's application of Section 202(c) consistently confirms the urgency of the conditions necessary to invoke the provision and underscores the lack of authority for the planned implementation scheme described in the Grid EO and RAR.[33] The Department's predominant practice has been to use Section 202(c) to address specific, imminent, and unexpected shortages—not to address longer-term reliability concerns or demand forecasts.[34]

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[31] *See, e.g., Richmond Power & Light,* 574 F.2d at 617 (Section 202(c) "speaks of 'temporary' emergencies, epitomized by wartime disturbances, and is aimed at situations in which demand for electricity exceeds supply and not at those in which supply is adequate but a means of fueling its production is in disfavor.").

[32] 10 C.F.R. § 205.371: "'Emergency,' as used herein, is defined as an unexpected inadequate supply of electric energy which may result from the unexpected outage or breakdown of facilities for the generation, transmission or distribution of electric power. Such events may be the result of weather conditions, acts of God, or unforeseen occurrences not reasonably within the power of the affected 'entity' to prevent. An emergency also can result from a sudden increase in customer demand, an inability to obtain adequate amounts of the necessary fuels to generate electricity, or a regulatory action which prohibits the use of certain electric power supply facilities. Actions under this authority are envisioned as meeting a specific inadequate power supply situation. Extended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities can result in an emergency as contemplated in these regulations. In such cases, the impacted 'entity' will be expected to make firm arrangements to resolve the problem until new facilities become available, so that a continuing emergency order is not needed. Situations where a shortage of electric energy is projected due solely to the failure of parties to agree to terms, conditions or other economic factors relating to service, generally will not be considered as emergencies unless the inability to supply electric service is imminent. Where an electricity outage or service inadequacy qualifies for a section202(c) order, contractual difficulties alone will not be sufficient to preclude the issuance of an emergency order."

[33] *See FTC v. Bunte Brothers, Inc.*, 312 U.S. 349, 352 (1941) ("[J]ust as established practice may shed light on the extent of power conveyed by general statutory language, so the want of assertion of power by those who presumably would be alert to exercise it, is equally significant in determining whether such power was actually conferred.").

[34] *See, e.g.,* Dep't of Energy Order No. 202-22-4 (Dec. 24, 2022) (responding to ongoing severe winter storm producing immediate and "unusually high peak load" between December 23 and

The law also requires the Department to narrowly tailor the remedies in Section 202(c) orders to ensure that the orders only address the stated emergency, limit the order to "only [the] hours necessary to meet the emergency," be "consistent with any applicable Federal, State, or local environmental law or regulation," and to "minimize[] any adverse environmental impacts.[35] Up until recently, the Department has routinely followed these provisions of the law.[36]

2. DOE's Recent Misuse of Section 202(c)

Prior to issuance of the RAR but consistent with the direction in the Grid EO, DOE issued two Section 202(c) orders blocking the planned closures of two fossil-fuel fired generation resources that were unreliable, uneconomic, and at the end of their useful lives: the J.H. Campbell coal-fired plant in West Olive Michigan,[37] and units 3 and 4 of the Eddystone oil and gas fired plant in Eddystone, Pennsylvania.[38] The Eddystone 202(c) Order stated that "DOE plans to use this methodology [i.e., the RAR] to further evaluate Eddystone Units 3 and 4," thus raising questions about DOE's intentions as to the legal status and efficacy of the RAR.

Public Interest Organizations filed requests for rehearing for both the J.H. Campbell and Eddystone 202(c) Orders.[39] In both cases DOE failed to identify conditions that would qualify as "emergencies" for the purpose of issuance of Section 202(c) Orders. And both Section 202(c) Orders impose significant costs on ratepayers,[40] while increasing emissions of air pollutants and providing no

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December 26) (attached as Ex.5); Department of Energy Order 202-20-2 (Sept. 6, 2020) at 10-2 (responding to shortages produced by ongoing extreme heat and wildfires) (attached as Ex.6); *see also* Benjamin Rolsma, *The New Reliability Override*, 57 CONN. L. REV. 789, 803-4 (describing "sparing[]" use of Section 202(c) outside of wartime shortages during the twentieth century) (attached as Ex. 7).

[35] 16 U.S.C.§ 824a(c)(2).

[36] *See, e.g.,* Ex.5, Dep't of Energy Order No. 202-22-4 (Dec. 24, 2022) at 4-7 (limiting order to the 3 days of peak load, directing PJM to exhaust all available resources beforehand, requiring detailed environmental reporting, notice to affected communities, and calculation of net revenue associated with actions violating environmental laws); Ex.6, Dep't of Energy Order 202-20-2 (Sept. 6, 2020) at 3-4 (limiting order to the 7 days of peak load, directing CAISO to exhaust all available resources beforehand, requiring detailed environmental reporting).

[37]Dep't of Energy Order No. 202-25-3 (May 23, 2025) (attached as Ex. 8).

[38]Dep't of Energy Order No. 202-25-4 (May 30, 2025) (hereinafter "Eddystone 202(c) Order") (attached as Ex. 9).

[39] Mot. to Intervene and Request for Rh'g and Stay of Pub. Int. Orgs., DOE Ord. No. 202-25-3 (June 18, 2025) (hereinafter "Campbell RFR") (attached as Ex.10);Mot. to Intervene and Request for Rh'g and Stay of Pub. Int. Orgs., DOE Ord. No. 202-25-4 (June 27, 2025) (hereinafter "Eddystone RFR") (attached as Ex.11).

meaningful corresponding reliability benefit.[41] The Department denied both of Public Interest Organization's requests for rehearing by operation of law.[42]

D. Existing Mechanisms Ensure Resource Adequacy

In the United States, how electricity is bought and sold varies by region. Electric utilities can be either traditionally regulated and operate as vertically integrated monopolies, or they can operate in deregulated, competitive markets where electric energy prices are set by the market. Both vertically integrated utilities and utilities in deregulated markets are subject to federal oversight, and in some of the deregulated states, the state nonetheless exercises oversight over the terms of retail supply offers, especially for retail customers. And all utilities are subject to reliability standards developed by the North American Electric Reliability Corporation ("NERC") and approved by FERC. In sum, FERC, Regional Transmission Organizations ("RTOs"), States, and NERC all play a hand in ensuring resource adequacy.

1. Vertically integrated utilities

Until the 1990s, utilities were generally vertically integrated such that generation, transmission, and distribution resources were all held by the same entity.[43] Vertically integrated utilities must seek state approval for power plant investments.[44] Many state regulators require utilities to demonstrate the necessity of proposed investments through an integrated resource planning process.[45] This process is used for long-term planning and requires the utility to justify its investments and demonstrate how it plans to meet customer electricity demand.[46] Even though vertically integrated utilities generate their own electricity, many

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[40] *See e.g.* U.S. Sec. and Exch. Comm'n, Form 10-Q, Consumers Energy Company Quarterly Report For the Quarterly Period Ended June 30, 2025, at 39, 62, 92 (2025) https://d18rn0p25nwr6d.cloudfront.net/CIK-0000201533/10a900b7-263b-4ccd-82a0-4162ba7ae5f2.pdf (describing costs of $29 million to operate Campbell through June 30, 2025); FERC Docket No. ER25-2653-000 (PJM proposed cost allocation to implement DOE Order 202-25-4).

[41] *See* Campbell RFR, Ex. 10 at 11-14; Eddystone RFR, Ex. 11 at 56-60. 87-88.

[42] Dep't of Energy, Notice of Denial of Reh'g by Operation of Law and Providing for Further Consideration of Ord. No. 202-25-3A (July 28, 2025) (attached as Ex. 12); Dep't of Energy, Notice of Denial of Reh'g by Operation of Law and Providing for Further Consideration of Ord. No. 202-25-4A (Aug. 1, 2025) (attached as Ex. 13).

[43] *See* Kathryne Cleary and Karen Palmer, *US Electricity Markets 101* (March 17, 2022), Resources for the Future, https://www.rff.org/publications/explainers/us-electricity-markets-101/.

[44] *Id.*

[45] *Id.*

[46] *Id.*

trade with other utilities during times of need. These wholesale market transactions are subject to regulation by FERC.[47]

2. Competitive markets

Advances in technology and statutory changes led to the development of energy markets and merchant generation that is not owned by incumbent utilities.[48] In the 1990s, FERC fostered competitive markets through rules that allowed the establishment of independently-operated voluntary RTOs that determine the prices for energy, capacity, and ancillary services based on procurement and dispatch of least-cost resources through Order Nos. 888, 890, and 2000.[49] As RTO markets expanded, many states deregulated their utility monopolies and required them to join RTOs. Deregulated states use markets to determine which power plants are necessary for electricity generation.[50] Even in deregulated states, the state sites new generation. Market price signals encourage new investment when supply is tight and encourage the retirement of facilities that are no longer competitive when capacity is plentiful. RTOs now account for approximately 2/3 of all electricity sales in the U.S. and have saved consumers billions of dollars, increased reliability, and reduced environmental harm.[51]

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[47] *See* FERC, *Electric Power Markets* (last updated March 27, 2025), https://www.ferc.gov/electric-power-markets.

[48] *See, e.g.,* Order Terminating Rulemaking Proceeding, Initiating New Proceeding, And Establishing Additional Procedures, 162 FERC ¶ 61,012, PP 7-11 (2018); Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 31,639-31,645 (1996), order on reh'g, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, order on reh'g, Order No. 888-B, 81 FERC ¶ 61,248 (1997), order on reh'g, Order No. 888-C, 82 FERC ¶ 61,046 (1998), aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC, 225 F.3d 667 (D.C. Cir. 2000), aff'd sub nom. *New York v. FERC*, 535 U.S. 1 (2002).

[49] Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 638-41 (1996), Order No. 890, FERC Stats. & Regs. ¶ 31,241, at 124-352 (1997), Order No. 2000, FERC Stats. & Regs. ¶ 31,089, at 99-130 (1999).

[50] State regulators in competitive markets still practice oversight over utilities. For example, some states, such as Michigan, use both the market and integrated resource planning. *See* Michigan Public Service Commission, *Phase III – Integrated Resource Plan* (last visited Aug. 4, 2025), https://www.michigan.gov/mpsc/commission/workgroups/mi-power-grid/phase-iii-integrated-resource-plan-mirpp-filing-requirements-demand-response-study-energy-waste-red. Other state legislatures or commissions have enacted subsidies to keep nuclear plants alive, such as in New York, Illinois, Ohio, and New Jersey. *See* U.S. EIA, Five states have implemented programs to assist nuclear power plants (Oct. 7, 2019), https://www.eia.gov/todayinenergy/detail.php?id=41534.

[51] *See, e.g.*, Judy Chang et al., The Brattle Group, Potential Benefits of a Regional Wholesale Power Market to North Carolina's Electricity Customers, 1, 3-7 (April 2019) https://www.brattle.com/wp-content/uploads/2021/05/16092_nc_wholesale_power_market_whitepaper_april_2019_final.pdf (discussing billions of dollars in estimated cost saving); Jennifer Chen & Devin Hartman, *Why wholesale market benefits are not always apparent in customer bills*, R Street (Nov. 10, 2021), https://www.rstreet.org/commentary/why-wholesale-market-benefits-are-not-always-apparent-in-

As explained by FERC, its "support of competitive wholesale electricity markets has been grounded in the substantial and well-documented economic benefits that these markets provide to consumers."[52] In addition to billions of dollars of consumer savings, FERC found that competitive markets protect consumers by "providing more supply options, encouraging new entry and innovation, spurring deployment of new technologies, promoting demand response and energy efficiency, improving operating performance, exerting downward pressure on costs, and shifting risk away from consumers."[53]

3. FERC and NERC Reliability Regulation

As part of its role in regulating the wholesale electric industry, FERC has implemented Congressional mandates to ensure system reliability, including establishing NERC as the Electric Reliability Organization, which sets industry standards for grid reliability that are approved by FERC;[54] coordination requirements for the natural gas and electricity market scheduling;[55] investigation and improvements required in light of the grid's response to extreme weather events;[56] and reviewing capacity accreditation processes to ensure that capacity markets generate reliable results.[57]

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customer-bills/ (same); Jeff St. John, *A Western US energy market would boost clean energy. Will it happen?*, Canary Media (Jun. 10, 2024), https://www.canarymedia.com/articles/utilities/a-western-us-energy-market-would-boost-clean-energy.-will-it-happen; John Tsoukalis et al., Assessment of Potential Market Reforms for South Carolina's Electricity Sector, at 6, 46, 77-78 (Apr. 27, 2019), https://www.scstatehouse.gov/CommitteeInfo/ElectricityMarketReformMeasuresStudyCommittee/2022-04-27%20-%20SC%20Electricity%20Market%20Reform_Brattle%20Report.pdf (discussing cost savings across regional wholesale markets).

[52] Order Terminating Rulemaking Proceeding, Initiating New Proceeding, and Establishing Additional Procedures, 162 FERC ¶ 61,012, P 11 (2018).

[53] *Id.* (citation omitted).

[54] PJM, NERC and Reliability Fact Sheet (Jan. 5, 2025), https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/nerc-and-reliability-fact-sheet.pdf. *See also* PJM, PJM Ensures a Reliable Grid (Jan. 29, 2025), https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/reliability-fact-sheet.pdf.

[55] PJM, PJM Promotes Gas/Electricity Industry Coordination (Jan. 29, 2025), https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/gas-electric-coordination-fact-sheet.pdf. *See also* Order 787, 145 FERC ¶ 61,134 (2013); Order 809, 151 FERC ¶ 61,049 (2015).

[56] *See e.g.,* Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, 149 FERC ¶ 61,145 (2014) (order addressing technical conferences on, among other things, the 2014 Polar Vortex); Order Approving Extreme Cold Weather Reliability Standards EOP-011-3 and EOP-012-1 and Directing Modification of Reliability Standard EOP-012-1, 182 FERC ¶ 61094 (2023); Order Approving Extreme Cold Weather Reliability Standard EOP-012-2 and Directing Modification, 187 FERC ¶ 61,204 (2024). *See also* FERC, NERC and Regional Staff, Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott (Oct. 2023), https://www.ferc.gov/sites/default/files/2023-11/24_Winter-Storm_Elliot_1107_1300.pdf; FERC, NERC and Regional Entity Joint Staff, The February 2021 Cold Weather Outages in Texas and the

V. ARGUMENT

A. The Department Is Intruding on FERC and State Authority.

The Department's authority over reliability is strictly circumscribed to respond to imminent emergencies;[58] this authority does not extend to regulating long-term or overarching aspects of the electricity sector. Rather, Congress reserved to the states and FERC the authority to regulate the electric sector generally and to regulate resource adequacy and reliability specifically. Recent actions—starting with the Energy Emergency EO and culminating in the RAR—indicate, however, that DOE is not remaining in its designated lane.[59] The RAR lays bare the Department's agenda to prop up fossil fuel businesses by utilizing emergency authority in a systematic fashion that goes well beyond the scope of DOE's authority under the Federal Power Act and illegally intrudes upon authorities that Congress has explicitly reserved to the states or given to FERC.

The authority to maintain a reliable electric system in the United States has evolved over the years to include parties at the federal, regional, state, and local levels.[60] But the Department of Energy has never been granted primary regulatory authority over either reliability or resource adequacy of the grid. Rather, the Department of Energy Organization Act of 1977 ("Organization Act")[61] and the

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South Central United States (Nov. 2021), https://www.nerc.com/pa/Stand/Project202107ExtremeColdWeatherDL/FERC%20Presentation-Phase%202.pdf; PJM, Winter Storm Elliott Event Analysis and Recommendation Report (2023), https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/20230717-winter-storm-elliott-event-analysis-and-recommendation-report.pdf.

[57] *Id.*; *see also* Order Accepting Tariff Revisions Subject to Condition, 186 FERC ¶ 61,080 (2024).

[58] *See* 16 U.S.C. §§ 824a(c),824o-1.

[59] *See* Energy Emergency EO, Ex. 4; Grid EO Sec. 3 (RAR, Ex. 1 at C); RAR Ex. 1; DOE, DOE Fact Sheet, https://www.energy.gov/sites/default/files/2025-07/DOE_Fact_Sheet_Grid_Report_July_2025.pdf; DOE Press Release, https://www.energy.gov/articles/department-energy-releases-report-evaluating-us-grid-reliability-and-security; Eddystone 202(c) Order, Ex. 9; Dep't of Energy Order No. 202-25-3 (May 23, 2025), Ex. 8.

[60] *New York v. FERC*, 535 U.S. 1, 5-8 (2002) ("Prior to 1935, the States possessed broad authority to regulate public utilities"). *See generally* Nat'l Ass'n of Reg. Util. Comm'rs ("NARUC"), *Resource Adequacy for State Utility Regulators: Current Practices and Emerging Reforms* (Nov. 2023) https://pubs.naruc.org/pub/0CC6285D-A813-1819-5337-BC750CD704E3?_gl=1*oyp366*_ga*MTc1NzM0NTE0LjE3NTM5ODk1NDA.*_ga_QLH1N3Q1NF*czE3NTM5ODk1NDAkbzEkZzEkdDE3NTM5ODk1NzUkajI1JGwwJGgw; NARUC, *Resource Adequacy Primer for State Regulators* (July 2021), https://pubs.naruc.org/pub/752088A2-1866-DAAC-99FB-6EB5FEA73042?_gl=1*1mituzu*_ga*MTc1NzM0NTE0LjE3NTM5ODk1NDA.*_ga_QLH1N3Q1NF*czE3NTM5ODk1NDAkbzEkZzAkdDE3NTM5ODk1NDAkajYwJGwwJGgw.

[61] 42 U.S.C. § 7111 *et seq.*

Federal Power Act[62] give to the Department only narrow, emergency authority over the electric system—for example through Federal Power Act Sections 202(c) and 215A.[63] The President's declaration of an energy emergency (even if it were legitimate) and other executive orders cannot expand these statutorily defined authorities.[64] And while the Department may of course analyze policy implications and issue reports on various topics—as it has done since its founding—DOE's statements indicate that the RAR is not simply a policy analysis. The Department states—without limitation—that it will use the RAR "to identify at-risk region(s) and guide reliability interventions."[65] Thus, taking DOE at its word, the RAR is beyond the Department's authority.

Further, to the extent that it is an indication of the Department's broader scheme, in the RAR, the Department ignores the limitations on its authority and the comparative breadth of authority explicitly reserved to the states and FERC over the Department. "States are responsible for resource adequacy in siting of electric facilities, establishing retail electric rates, and overseeing the reliability of the distribution system."[66] State public utility commissions review utility proposals for long-term impacts to the system's reliability. "Most states address resource adequacy by requiring large investor-owned utilities to file long-term planning documents like integrated resource plans that include strategies for reliably meeting future demand."[67]

The structure and language of the Organization Act and Federal Power Act reflect Congress's deliberate choices to preserve this traditional state authority over generating facilities and to circumscribe the Department's emergency authority in light of the states' role. Congress noted in the Organization Act that "[n]othing in this chapter shall affect the authority of any State over matters exclusively within its jurisdiction."[68] And the first sentence of the Federal Power Act declares that

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[62] Subsequent legislation has also amended and updated these authorities. *See e.g.* Fixing America's Surface Transportation Act (FAST Act), Pub. L. No. 114–94, 129 Stat. 1312 (2015); Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594 (2005).

[63] 16 U.S.C. §§ 824a(c), 824o-1.

[64] *See Biden v. Nebraska*, 600 U.S. 477, 500-01 (2023); *see also* S. Rep. No. 94-1168, 3 (1976), (the National Emergencies Act "is not intended to enlarge or add to Executive power. Rather, the statute is an effort by Congress to establish clear procedures and safeguards for the exercise by the President of emergency powers *conferred on him by other statutes*.") (emphasis added).

[65] RAR, Ex. 1 at vi.

[66] NARUC, *Resource Adequacy Primer for State Regulators*, at 9 (July 2021) https://pubs.naruc.org/pub/752088A2-1866-DAAC-99FB-6EB5FEA73042?_gl=1*1mituzu*_ga*MTc1NzM0NTE0LjE3NTM5ODk1NDA.*_ga_QLH1N3Q1NF*czE3NTM5ODk1NDAkbzEkZzAkdDE3NTM5ODk1NDAkajYwJGwwJGgw.

[67] Nat'l Renewable Energy Lab'y, *Explained: Fundamentals of Power Grid Reliability and Clean Electricity*, at 4 (Jan. 2024) https://docs.nrel.gov/docs/fy24osti/85880.pdf.

[68] 42 U.S.C. § 7113.

federal regulation extends "only to those matters which are not subject to regulation by the States."[69] Section 201(b)(1) further states that, except as otherwise "specifically" provided, federal jurisdiction does not attach to "facilities used for the generation of electric energy."[70] The courts have held that Section 201(b)(1) reserves to the states authority over electric generating facilities,[71] including the authority to order their closure.[72] Congress also recognized the states' exclusive authority over generating facilities in Section 202(b), which provides that FERC's interconnection authority does not include the power to "compel the enlargement of generating facilities for such purposes."[73] And when Congress added new authority regarding reliability to the Federal Power Act in 2005, it also still explicitly clarified that "[n]othing in this section shall be construed to preempt any authority of any State to take action to ensure the safety, adequacy, and reliability of electric service within that State, as long as such action is not inconsistent with any reliability standard…."[74]

The RAR also intrudes upon authority that Congress explicitly and repeatedly gave exclusively to FERC, not the Department. In 1935, Congress passed the Federal Power Act, creating the Federal Power Commission to engage in "federal regulation of electricity in areas beyond the reach of state power."[75] However, until the 1970s, the federal government played a very limited role in energy policy and generally left to private industry and state and local governments the task of establishing energy policies and planning.[76] In 1977, Congress passed the Organization Act,[77] creating both the Department and FERC. The Organization Act transferred most of the authority for overseeing the electric system in the

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[69] 16 U.S.C. § 824(a).

[70] *Id.* § 824(b)(1).

[71] *See, e.g., Hughes v. Talen Energy Mktg., LLC*, 578 U.S. 150, 154 (2016).

[72] *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (2009) (under Section 201(b), states retain the right "to require retirement of existing generators" or to "take any other action in their role as regulators of generation facilities."). *See also 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.").

[73] 16 U.S.C. § 824a(b).

[74] 16 U.S.C. § 824o.

[75] *New York v. FERC*, 535 U.S. 1, 6 (2002).

[76] DOE, *A Brief History of the Department of Energy,* https://www.energy.gov/lm/brief-history-department-energy. *See also* DOE, *Department of Energy 1977-1994, A Summary History* (Nov. 1994), https://www.energy.gov/sites/prod/files/2017/09/f36/DOE%201977-1994%20A%20Summary%20History_0.pdf.

[77] Public Law 95–91 (1977), 42 U.S.C. § 7101 *et seq.*

Federal Power Act to FERC, not the Department;[78] the Department retained primary authority only over "emergency interconnection."[79]

While FERC is housed within the Department, FERC is an independent agency with distinct authority from the Department that the Department may not modify or supersede.[80] Generally the Department "is authorized to establish, alter, consolidate or discontinue such organizational units or components within the Department as [the Secretary] may deem to be necessary or appropriate."[81] But this authority explicitly does not extend to FERC. The Organization Act explains that the Department may not abolish "organizational units or components established by" the Organization Act, nor may it "transfer [] functions vested by this chapter in any organizational unit or component."[82] Because the Organization Act created[83] and transferred specific authority to FERC,[84] the Department has no authority to alter FERC itself nor to seize FERC's statutorily prescribed authority.

Further, "the decision of the Commission involving any function within its jurisdiction . . . shall be final agency action . . . and *shall not be subject to further review by the Secretary* or any officer or employee of the Department."[85] While the Department can propose rules under FERC's jurisdiction, FERC maintains "exclusive jurisdiction . . . to take final action on any proposal made by the Secretary."[86] And when the Department proposes a rule in the exercise of its own functions that FERC determines significantly affects any function within FERC's jurisdiction, FERC can insist on changes that DOE must adopt if DOE wants to issue the rule.[87]

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[78] 42 U.S.C. § 7172 (transferring functions from Federal Power Commission to FERC); 42 U.S.C. § 7151 (the function of the Federal Power Commission is transferred to the Secretary except as provided to FERC). The Department and FERC share authority over certain parts of the Federal Power Act that primarily address recordkeeping and administration. 42 U.S.C. § 7172(a)(2) ("The Commission may exercise any power under the following sections to the extent the Commission determines such power to be necessary to the exercise of any function within the jurisdiction of the Commission: (A) sections 4, 301, 302, 306 through 309, and 312 through 316 of the Federal Power Act.").

[79] *See* 42 U.S.C. § 7172(a)(1)(B).

[80] *See* 42 U.S.C.A. § 7112 (Congressional declaration of purpose in establishing Department); 42 U.S.C. § 7171 (establishment of FERC).

[81] 42 U.S.C. § 7253.

[82] 42 U.S.C. § 7253.

[83] 42 U.S.C. § 7171 (establishment of FERC).

[84] 42 U.S.C. § 7172(a) (transferring functions from Federal Power Commission to FERC).

[85] 42 U.S.C. § 7172(g) (emphasis added).

[86] 42 U.S.C. § 7173. *See* 162 FERC ¶ 61,012.

[87] 42 U.S.C. § 7174.

In 2005, Congress expanded FERC's authority to specifically encompass reliability by updating the Federal Power Act in the 2005 Energy Policy Act.[88] While "FERC had previously addressed electric grid reliability in an indirect manner, such as allowing the cost recovery of public utility expenditures that address discrete reliability matters,"[89] there had been no mandatory reliability standards adopted by any federal regulator. When providing recommendations on reliability in 1998, the Department had concluded "that the U.S. Congress should explicitly assign oversight of bulk-power reliability to the FERC."[90] The new Section 215 followed the Department's suggestion and "tasked FERC [—not the Department—] with a direct role over an entire new field of activity."[91] Section 215 authorizes FERC to certify an electric reliability organization; FERC designated NERC. It is therefore NERC that develops reliability standards that FERC reviews to ensure consistency with federal law.[92] The broad reliability authority Congress granted to FERC contrasts with the very narrow, emergency authority in Section 215A that Congress granted to the Department.[93] The RAR appears to duplicate FERC and NERC's reliability efforts, impermissibly intruding upon authority Congress chose to give FERC —subject to elaborate procedural and substantive limitations—not the Department.

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[88] Pub. L. No. 109-58, 119 Stat. 594 (2005).

[89] FERC, *Reliability Primer*, at 5 (2020) https://www.ferc.gov/sites/default/files/2020-04/reliability-primer_1.pdf.

[90] DOE, *Maintaining Reliability in a Competitive U.S. Electricity Industry* at vii-viii, xiv (Sept. 29, 1998), https://certs.lbl.gov/sites/all/files/basic-page/maintainting-reliability-in-competitive-electricity-industry-1998_0.pdf ("The Administration has proposed legislation that would provide the federal oversight necessary to make reliability standards mandatory. The NERC has begun to reinvent itself to respond to the changing needs of the industry. In addition, the FERC has undertaken several reliability initiatives. However, much more is needed. The Congress, for example, urgently needs to clarify the FERC's authority over an electric industry self-regulating reliability organization and expand the FERC's jurisdiction for reliability over the bulk-power system.") ("The Task Force is confident that the electricity industry, overseen by the Federal Energy Regulatory Commission (FERC) and a restructured self-regulating reliability organization (such as the planned North American Electric Reliability Organization [NAERO]), can and will maintain today's high levels of reliability."). *See also* S. Rep. No. 106-324, Electric Reliability 2000 Act (proposals from Congress such as this one gave FERC the authority over reliability).

[91] FERC, *Reliability Primer*, at 5 (2020) https://www.ferc.gov/sites/default/files/2020-04/reliability-primer_1.pdf.

[92] FERC, Reliability Explainer (Aug. 16, 2023) https://www.ferc.gov/reliability-explainer#:~:text=Both%20NERC%20and%20FERC%20have,blackouts%20or%20systematic%20compliance%20failures.

[93] The 2015 amendment to Federal Power Act creating Section 215A (16 U.S.C. 824o-1(d)) gives DOE the authority to issue orders to address emergencies related to malicious acts resulting from physical attacks to the grid at limited 15-day increments.

Finally, the Department arbitrarily and capriciously assumes that the existing systems are not working. The states and FERC have—pursuant to their authority—established systems to maintain resource adequacy and reliability including integrated resource planning processes and capacity markets. These existing systems are designed to signal to build more energy generation when energy demand rises.[94] Recently, as the Department notes in the RAR, energy demand has been rising; but the Department fails to acknowledge that the state and FERC systems already are appropriately responding, negating claims of an emergency or the need for the Department to interfere, as discussed *infra* in Section C.[95] For example, PJM's, SPP's, and MISO's new "fast track" processes—adopted to address concerns of resource adequacy—"alone would add roughly twice what the DOE assumed for the entire nation."[96] The RAR is written arbitrarily and capriciously incorporating the implicit assumption that capacity market results are not reliable, and that market-driven generator retirement is cause for alarm.

In sum, Congress has explicitly reserved to the states and FERC primary regulatory authority over resource adequacy and reliability. The Department's only authority to directly regulate reliability of the electric grid is narrow emergency authority such as Federal Power Act Sections 202(c) and 215A. The Department does not have broader authority to interfere with resource adequacy or reliability regulations. To the extent that the RAR is the confirmation of the attempt to usurp that authority from the states and FERC, via a "uniform methodology" in the RAR, it is outside of DOE's statutory authority and contrary to law.

B. The Department's Findings in the RAR, Even if Accurate, Do Not Demonstrate Any Emergency Allowing the Department to Compel Generation Under the Federal Power Act.

Even if the findings in the RAR were accurate (which they are not, as explained in Section C below), they would not empower the Department to exercise any statutory authority, under "section 202 of the Federal Power Act" or otherwise, to override state- or market-driven changes to the electricity generating facilities supplying the grid.[97] As discussed in Section A above, the Federal Power Act gives the Department tightly circumscribed authority over resource adequacy planning, to address "emergency" conditions through "such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy" as

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[94] *See e.g.* DOE, A Primer on Electric Utilities, Deregulation, and Restructuring of U.S. Energy Markets, at 3.8 (May 2002); GridLab, GridLab Analysis: Department of Energy Resource Adequacy Report, at 4 (July 11, 2025) (hereinafter "GridLab Analysis") (attached as Ex. 14).

[95] GridLab Analysis, Ex. 14 at 2-3.

[96] GridLab Analysis, Ex. 14 at 3.

[97] Grid EO at Sec. 3 (RAR, Ex. 1 at C-3).

"will best meet the emergency and serve the public interest."[98] The statutory text, structure, and history, as well as case law interpreting Section 202(c), the Department's regulations, and its historic use of Section 202(c), all establish that its "emergency" authority is confined to sudden, unexpected, imminent, and specific electricity shortfalls. The information in the RAR, at most, expresses the Department's view that bulk-power system reliability will be insufficient in 2030. The Department's conclusions in the RAR—even if assumed to be accurate for the sake of argument—consequently provide no basis for the Department to manipulate the electricity market.

1. The Federal Power Act only permits the Department to intervene when necessary to address an imminent, unexpected, and specific electricity shortfall.

The Federal Power Act's text, context, and structure, as well as caselaw and the Department's longstanding regulations, all establish that it does not permit the Department to "prevent" generating facilities "from leaving the bulk-power system" or "converting" from one fuel-source to another based on the Department's view of long-term reliability needs.[99] The Act provides the Department only authority to intervene in electricity markets when necessary to address imminent, near-term, and exigent electricity supply shortfalls requiring immediate response, through the cabined authority provided by Section 202(c) of the Act.

a. The Text of Section 202(c) Narrowly Limits the Department's Authority to Emergencies: Imminent, Unexpected, and Certain Shortfalls in Electricity Supply.

The Act's text empowers the Department to require generation only in an "emergency;"[100] the Act primarily reserves authority over generation to the states, allocating more limited federal regulatory power to different agencies, *see section* A above. The statute itself does not define "emergency." At the time Congress enacted Section 202(c), Webster's New International Dictionary of the English Language (1930) 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."[101] Contemporary dictionaries similarly define "emergency" as demanding imminence: an emergency

[98] 16 U.S.C. 824a(c).

[99] Grid EO at Sec. 3(c)(ii) (RAR, Ex. 1 at C-4).

[100] 16 U.S.C. § 824a(c).

[101] Emphasis added.

is "an *unforeseen* combination of circumstances or the resulting state that calls for *immediate* action."[102]

The remainder of Section 202(c) underscores the exigency inherent in the governing term "emergency." The authority granted by Section 202(c) is, in the first instance, a war-time power.[103] An "emergency" under the statute is limited to circumstances of similar urgency: "a *sudden* increase in the demand for electric energy," for example.[104]

The text's use of the present tense also underscores that focus on imminent and certain shortfalls: it empowers the Department to act only where "an emergency *exists*."[105] That near-term focus along with the statute's strictly "temporary" authority[106] precludes use of Section 202(c) to pursue long-term policy goals, such as "fear of overdependence" on foreign oil supplies,[107] or "energy independence."[108]

Section 202's overall structure further highlights Section 202(c)'s emphasis on imminent, near-term concerns. The preceding subsections 202(a) and (b) together define and limit the tools by which the federal government may pursue "abundant" energy supplies in the normal course.[109] The resulting statutory "machinery for the

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[102] Merriam Webster's Dictionary 407 (11th ed. 2009) (emphasis added); *see* 3 Oxford English Dictionary 119 (1st ed. 1913) (defining emergency similarly as "a state of things *unexpectedly* arising, and urgently demanding *immediate* action" (emphasis added)); *see also* Rolsma, Ex. 7 at 812 n.147 (noting that dictionaries have given the term "emergency" the "same meaning for many years").

[103] 16 U.S.C. § 824a(c) (beginning with "[d]uring the continuance of any war in which the United States is engaged"); *see Jarecki v. G.D. Searle & Co.*, 367 U.S. 303, 307 (1961) (noting that statutory terms should be interpreted in the context of nearby parallel terms "in order to avoid the giving of unintended breadth to the Acts of Congress").

[104] 16 U.S.C. § 824a(c) (emphasis added); *see Richmond Power & Light,* 574 F.2d at 615 (holding that Section 202(c) "speaks of 'temporary' emergencies, epitomized by wartime disturbances"); S. Rep. No. 74-621, at 49 (1935) (explaining that Section 202(c) provides "temporary power designed to avoid a repetition of the conditions during the last war, when a serious power shortage arose").

[105] 16 U.S.C. § 824a(c) (emphasis added).

[106] 16 U.S.C. § 824a(c).

[107] *Richmond Power & Light*, 574 F.2d at 617.

[108] RAR, Ex. 1 at 1. *See Richmond Power & Light*, 574 F.2d at 614 (Section 202(c) "speaks of 'temporary' emergencies, epitomized by wartime disturbances, and is aimed at situations in which demand for electricity exceeds supply and not those in which supply is adequate but a means of fueling its production is in disfavor.").

[109] 16 U.S.C. § 824a(a) (seeking "abundant supply of electric energy" by directing the federal government to "divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy") & 824a(b)

promotion of the coordination of electric facilities" comprises the following: in subsection (a), an instruction to establish a general framework meant to facilitate "coordination by voluntary action;" in subsection (b), "limited authority to compel interstate utilities to connect their lines and sell or exchange energy," subject to defined procedural and substantive requirements, when "interconnection cannot be secured by voluntary action;" and in subsection (c), "much broader" but "temporary" authority "to compel the connection of facilities and the generation, delivery, or interchange of energy during times of war or other emergency."[110]

That tiered structure—relying on voluntary action for quotidian energy planning, specifying limited authority where that voluntary system fails, and allowing for "temporary" central command-and-control only in case of "emergency"—requires that Section 202(c) remain narrowly bounded to instances of an immediate and unavoidable "break-down in electric supply,"[111] rather than mere want of more abundant supply in the future.[112] Interpreting Section 202(c)'s "emergency" powers to encompass longer-term concerns—e.g., potential shortfalls years into the future, or an expected "expansion of artificial intelligence data centers and an increase in domestic manufacturing,"[113]—would unwind the careful balance of voluntary, market-driven action and federal power set out in subsections 202(a) and 202(b). Such an interpretation cannot be squared with the statutory text and structure.[114]

b. Congress' Enactment of a Specific, Cabined Scheme to Address Reliability Concerns Confirms that Section 202(c) Cannot be Expanded to Impose Requirements Related to Long-Term Reliability.

That the Department's Section 202 powers may not be used to enforce the Department's view of long-term reliability needs is confirmed by Section 215 of the Federal Power Act—which specifically and directly delineates the scope of federal power to enforce mandatory long-term reliability requirements for the bulk-power system.[115] Congress added Section 215 to the Federal Power Act in 2005 precisely because the Act as it then existed—including Section 202—did not provide the

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(allowing federal government to order "physical connection … to sell energy or to exchange energy" upon application, and after an opportunity for hearing).

[110] S. Rep. No. 74-621 at 49 (1935).

[111] *Id.*

[112] *cf.* Eddystone 202(c) Order, Ex. 9 at 2 (imposing responsibility on PJM "to ensure maximum reliability on its system").

[113] Grid EO at Sec. 1 (RAR, Ex. 1 at C-4).

[114] *See Otter Tail Power Co. v. Fed. Power Comm.*, 429 F.2d 232, 233-34 (1970) (holding that Section 202(c) "enables the Commission to react to a war or national disaster," while Section 202(b) "applies to a crisis which is likely to develop in the foreseeable future").

[115] 16 U.S.C. § 824o.

federal government with the power to enforce measures designed to ensure broad, long-term reliability.[116]

By enacting Section 215, Congress provided a comprehensive and carefully circumscribed scheme to empower the federal government to enforce long-term reliability requirements. That statutory scheme strikes a careful balance between state and federal authority, and between private, market-driven decisions and top-down control. Reliability standards are devised by NERC independent "of the users and operators of the bulk-power system" but with "fair stakeholder representation."[117] FERC may approve or remand those standards (but not replace them with its own) and is required to "give due weight" to NERC's "technical expertise" while independently assessing effects on "competition."[118] Section 215 provides specified enforcement mechanisms and procedures for reliability standards—which mechanisms conspicuously exclude the power to command specific generation resources to remain operational.[119] And Section 215 carefully preserves state authority over "the construction of additional generation" and in-state resource adequacy, establishing regional advisory boards to ensure appropriate state input on the administration of reliability standards.[120]

Interpreting Section 202(c) to permit the Department to mandate generation based on its own unfettered assessment of long-term bulk-system reliability would effectively allow the Department to bypass Section 215's procedural safeguards, constraints on federal authority, and protection of state power. Such a bypass would impermissibly "contradict Congress' clear intent as expressed in its more recent," reliability-specific "legislation," enacted "with the clear understanding" that the Department had "no authority" to address long-term reliability through Section

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[116] *See* 70 Fed. Reg. 53,118 ("In 2001, President Bush proposed making electric Reliability Standards mandatory and enforceable," leading to enactment of Section 215 in 2005); RAR of the National Energy Policy Development Group (May 2001) at p. 7-6, https://www.nrc.gov/docs/ml0428/ml042800056.pdf (noting that "[r]egional shortages of generating capacity and transmission constraints combine to reduce the overall reliability of electric supply in the country" and that "one factor limiting reliability is the lack of enforceable reliability standards" because "the reliability of the U.S. transmission grid has depended entirely on *voluntary* compliance," and then recommending "legislation providing for enforcement" of reliability standards (emphasis added)); S. Rep. No. 109-78 at 48 (2005) (Section 215 "changes our current voluntary rules system" for long-term reliability "to a mandatory rules system."). *See Alcoa, Inc. v. FERC*, 564 F.3d 1342, 1344 (D.C. Cir. 2009) (noting that prior to the Energy Policy Act of 2005, "the reliability of the nation's bulk-power system depended on participants' voluntary compliance with industry standards").

[117] 16 U.S.C. § 824o(c)-(d). *See also id.* 824o(a)(3) (defining reliability standards as "a requirement … to provide for reliable operation of the bulk-power system").

[118] *Id.* § 824o(d)(2)-(4).

[119] *Id.* § 824o(e).

[120] *Id.* § 824o(i)-(j).

202(c).[121] Congress has, in Section 215, directly established the mechanisms (and limitations) by which the federal government may compel action to ensure long-term electric-system reliability. In so doing, it has confirmed that the Department may not, through Section 202(c) "emergency" orders, use long-term reliability concerns to mandate the generation it views as required to address long-term reliability needs.

c. DOE's Regulations Similarly Establish that Section 202(c) Emergency Authority Can Only Be Invoked to Address Imminent, Certain Supply Shortfalls Requiring Immediate Response.

The Department's regulations demonstrate its own long-standing understanding that Section 202(c)'s authority is confined to imminent and unavoidable resource shortages, rather than a mechanism to address long-term concerns as to the reliability of the bulk-power system. The regulations define an emergency as "an *unexpected* inadequate supply of electric energy which may result from the *unexpected* outage or breakdown" of generating or transmission facilities—not a means of planning against distant expectations or risks.[122] Emergencies "may result" from a number of events.[123] The use of the verb "result," defined as "arise as a consequence, effect, or conclusion," suggests that the event triggering the emergency has already happened rather than that there is a speculation that it could occur.[124]

Moreover, the events are characterized by those produced by "weather conditions, acts of God, or unforeseen occurrences not reasonably within the power of the affected 'entity' to prevent."[125] Where the culprit is increased demand, it must be "a *sudden* increase in customer demand" producing a "*specific* inadequate power supply situation,"[126] rather than long-term demand projections producing general reliability concerns. The need for both specificity and certainty is repeated in the Department's regulations defining an inadequate energy supply: "A system may be considered to have" inadequate supply when "the projected energy deficiency . . . *will* cause the applicant [for a 202(c) Order] to be unable to meet its

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[121] *See FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 142 & 149 (2000); s*ee also Cal. Indep. Sys. Operator Corp. v. FERC*, 372 F.3d 395, 401–02 (D.C. Cir. 2004) ("Congress's specific and limited enumeration of [agency] power" over a particular matter in one section of the Federal Power Act "is strong evidence that [a separate section] confers no such authority on [agency].").

[122] 10 C.F.R. § 205.371 (emphasis added).

[123] *Id.* ("may result from the unexpected outage," "may be the result of weather conditions," "can result from a sudden increase in customer demand").

[124] Merriam-Webster's Collegiate Dictionary (11th ed. 2003) 1063.

[125] 10 C.F.R. § 205.371

[126] *Id.* (emphasis added).

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 customers."[127]

And while the regulations suggest that "inadequate planning or the failure to construct necessary facilities *can result* in an emergency," they recognize that the Department may not utilize a "continuing emergency order" to mandate long-term system planning.[128] An emergency may exist where past planning failures produce an immediate, present-tense shortfall (that is where, a shortfall *results* from insufficient planning); the Department has no authority to commandeer bulk-system reliability planning merely because it deems current plans inadequate to meet far-distant needs.[129] As the Department stated when it promulgated those regulations, the statute allows the Department to provide "assistance [to a utility] during a period of unexpected inadequate supply of electricity," but does not empower it to "solve long-term problems."[130]

d. Courts Have Uniformly Held that Section 202(c) Can Be Invoked Only in Immediate Crises.

Two courts have addressed the scope of authority under Section 202(c), and both determined that this Section applies only when there is a sudden, unexpected, imminent, and specific emergency.

Richmond Power and Light of City of Richmond, Indiana v. FERC, 574 F.2d 610 (D.C. Cir. 1978), arose out of the 1973 oil embargo. The Federal Power Commission needed to decide how to respond to oil shortages, and decided to call for the voluntary transfer for electricity from non-oil power plants to areas of the country that relied heavily on oil, such as New England.[131] The New England Power Pool was not convinced that the voluntary program would work and petitioned the Commission for a 202(c) order.[132] The Commission instead facilitated an agreement between state commissions and supplying utilities, which satisfied the New England Power Pool and it withdrew its petition.[133] A dissatisfied utility

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[127] 10 C.F.R. § 205.375 (emphasis added).

[128] 10 C.F.R. § 205.371 (also recognizing that "where a shortage of electricity is projected due solely to the failure of parties to agree to terms, conditions, or other economic factors" there is no emergency "unless the inability to supply electric service is *imminent*" (emphasis added)).

[129] *See* 10 C.F.R. § 205.375 (requiring present inability to meet demand to demonstrate inadequate energy supply).

[130] 46 Fed. Reg. at 39,985–86.

[131] 574 F.2d at 613.

[132] *Id.*

[133] *Id.*

sought judicial review of the Commission's decision to allow the withdrawal of the Section 202(c) petition.[134]

The court easily upheld the Commission's decision not to invoke Section 202(c).[135] Though the oil embargo had ended, the utility argued that the "high cost and uncertain supply of imported oil" justified an emergency order.[136] The Commission countered that the voluntary program had worked, the New England Power Pool never interrupted service, there was no need for a Section 202(c) order, and the court agreed.[137]

Trying another tactic, the utility argued that "dependence on imported oil leaves this country with a *continuing* emergency."[138] The court observed that Section 202(c) "speaks of 'temporary' emergencies, epitomized by wartime disturbances."[139] Interpreting this statutory language, the court upheld the Department's view that Section 202(c) cannot be used when "supply is adequate but a means of fueling its production is in disfavor."[140] Section 202(c) is not an appropriate means to implement long-term national policy to switch fuels. It is only a temporary fix for a temporary problem.

The Eighth Circuit has similarly held that Section 202(c) can only be used to respond to immediate crises. In *Otter Tail Power Co. v. Federal Power Commission*, 429 F.2d 232 (8th Cir. 1970), a utility insisted that the only way for the Federal Power Commission to properly order the utility to connect to a municipal power provider was to issue a Section 202(c) order. Demand for electricity in the city had increased, and the peak load of the municipal power provider was getting to be so high that both of its two generators would likely need to be used simultaneously in the near future, "causing a possible loss of service should one malfunction during a peak period."[141] To avoid this possible loss of service, the Federal Power Commission issued a Section 202(b) order, requiring the utility to connect the municipal power provider. The utility argued that the Federal Power Commission used the wrong section and should have used Section 202(c) instead.

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[134] *Id.* at 614.

[135] *Id.*

[136] *Id.*

[137] *Id.* at 615.

[138] *Id.* (emphasis added).

[139] *Id.*

[140] *Id.*

[141] *Id.* at 233-34.

The court explained that Section 202(c) "enables the Commission to react to a war or national disaster" by ordering "immediate" interconnection during an "emergency."[142] For non-emergency situations, "[o]n the other hand, Section 202(b) applies," including when there is a "crisis which is likely to develop in the foreseeable future but which does not necessitate immediate action on the part of the Commission."[143] The court upheld the Commission's use of Section 202(b) instead of Section 202(c) because there was no immediate emergency.

The case law uniformly supports the interpretation that Section 202(c) can only be used in acute, short-term, urgent emergencies.

e. The Department's Prior Orders Recognize that Section 202(c) Does Not Confer Plenary Authority Over Long-Term Resource Adequacy.

The Department's past applications of Section 202(c) corroborate the urgency of the emergency conditions that are the necessary predicate for any Department intervention under that section.[144] The Department's predominant practice outside of wartime has been to use Section 202(c) to address specific, imminent, and unexpected shortages—not to address longer-term reliability concerns or demand forecasts.[145] The Department has also narrowly tailored the remedies in Section 202(c) orders to ensure that the orders only address the stated emergency, to limit the order to the minimum period necessary, and to mitigate violations of environmental requirements and impacts to the environment.[146]

Public Interest Organizations are not aware of any instance in which the Department has utilized Section 202(c) to mandate generation the Department

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[142] *Id.* at 234 (citing 16 U.S.C. § 824a(c)).

[143] *Id.*

[144] *See FTC v. Bunte Brothers, Inc.*, 312 U.S. 349, 352 (1941) ("[J]ust as established practice may shed light on the extent of power conveyed by general statutory language, so the want of assertion of power by those who presumably would be alert to exercise it, is equally significant in determining whether such power was actually conferred.").

[145] *See, e.g.,* Ex. 5, Dep't of Energy Order No. 202-22-4 (Dec. 24, 2022) (responding to ongoing severe winter storm producing immediate and "unusually high peak load" between Christmas Eve and Boxing Day); Ex. 6 Dep't of Energy Order 202-20-2 (Sept. 6, 2020) at 10-2 (responding to shortages produced by ongoing extreme heat and wildfires); *see also* Ex.7 Rolsma, 57 Conn. L. Rev. at 803-4 (describing "sparing[]" use of Section 202(c) outside of war-time shortages during the twentieth century).

[146] *See, e.g.*, Ex. 5, Dep't of Energy Order No. 202-22-4 (Dec. 24, 2022) at 4-7 (limiting order to the 3 days of peak load, directing PJM to exhaust all available resources beforehand, requiring detailed environmental reporting, notice to affected communities, and calculation of net revenue associated with actions violating environmental laws); Ex. 6 Dep't of Energy Order 202-20-2 (Sept. 6, 2020) at 3-4 (limiting order to the 7 days of peak load, directing CAISO to exhaust all available resources beforehand, requiring detailed environmental reporting).

views as necessary to ensure long-term resource sufficiency—and for good reason.[147] Any such use would exceed the Department's statutory authority.

2. In the RAR, DOE purports to identify only long-term, uncertain, and generalized concerns with bulk-power system reliability, which do not enable the Department to compel generation pursuant to Section 202(c).

Given the statutory limitations described above, the RAR provides no basis for the Department to use Section 202(c) to require that particular "generation resources" are "retained as an available generation resource," or to "prevent . . . an identified generation resource . . . from leaving the bulk-power system or converting" its fuel source.[148] Nor does the Department identify any other source of legal authority for DOE to impose such requirements. In the RAR, the Department only purports to identify capacity shortages that might affect bulk-system reliability in 2030.[149] The Department acknowledges that all but one region—ERCOT—currently meet its criteria.[150] Its claim that shortages might arise five years from now, even if it were correct—would present no "emergency" under Section 202(c). Those non-imminent resource needs are, rather, precisely the long-term reliability and resource adequacy matters over which Congress allocated responsibility to FERC and NERC.

Second, the Department identifies only a "risk of power outages" even in 2030[151] based on the Department's projected "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."[152] The Department acknowledges, meanwhile that its analysis "is not an indication that reliability coordinators would allow this level of load growth to jeopardize the reliability of the system."[153] The RAR—even by its own terms—thus does not specify any shortfall that is certain enough to justify invocation of the Department's emergency powers under Section 202(c). Its numbers are, rather, "indicators to determine where it may be beneficial to encourage increased generation and transmission capacity to meet an expected need."[154] Section 202(c) does not authorize the Department to order generation based on such non-certain shortfalls; it provides distinct, and

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[147] *See Richmond Power and Light,* 574 F.2d at 616.

[148] Grid EO at 2.

[149] *E.g.,* RAR, Ex. 1 at 1, 20, 27, 30, 32, 40.

[150] RAR, Ex. 1 at 7.

[151] *Id.* at 1.

[152] *Id.* at 7.

[153] *Id.*

[154] *Id.*

much more limited powers, by which the Department may facilitate "an abundant supply of electric energy throughout the United States."[155]

And third, the Department does not claim to identify any particular location in which a shortfall might occur, or the specific resources that might best serve to address such shortfall. Instead, in the RAR, the Department provides aggregate estimates of potential loss-of-load under "varied grid conditions and operating scenarios based on historical data."[156] But those estimates do not demonstrate that any single generating facility would best meet the resulting shortfall, and could not therefore justify an emergency order directing a facility to remain available.

Consequently—even setting aside methodological flaws—the Department asserts resource risks in the RAR that are neither imminent, certain, nor specific. Those risks do not describe an emergency that would permit the Department to intervene pursuant to Section 202(c). They represent, rather, the Department's view as to measures that might "assur[e] an abundant supply of electric energy throughout the United States."[157] Section 202 does not permit the Department to compel generation on that basis. The Department also describes in the RAR the measures the Department believes "necessary to provide for reliable operation of the bulk-power system."[158] But Section 215 gives FERC, not the Department, the power to provide for reliable operation of the bulk power system, and specifies the procedures by which such measures must be developed and enforced; the Federal Power Act does not permit the Department to end-run those limitations by deeming long-term reliability an emergency. The RAR consequently could not form the basis of any action by the Department to compel generation under Section 202 of the Federal Power Act.

C. The RAR Is Analytically Flawed and Does not Rely Upon Substantial Evidence.

The RAR is severely flawed and does not meet DOE's own information quality standards. There are significant informational and methodological limitations and clear analytical and data errors. Any reliance on the RAR to "guide interventions" or to serve as a basis for any DOE decisionmaking would be arbitrary and capricious and not based on substantial evidence, in violation of the Administrative Procedure Act.

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[155] 16 U.S.C. § 824a(a).

[156] RAR, Ex. 1 at 2. *See, e.g., id.* at 21.

[157] 16 U.S.C. § 824a(a).

[158] 16 U.S.C. § 824o(a)(3).

1. The RAR falls woefully short of informational and methodological best practices.

DOE admits the RAR was hastily thrown together without sufficient information. At the outset, DOE acknowledges the resource adequacy analysis in the RAR "could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level."[159] Indeed, "[h]istorically, the nation's power system planners would have shared electric reliability information with DOE through mechanisms such as EIA-411, which has been discontinued."[160] DOE continues to explain that a key takeaway of the RAR is the need 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."[161] The candor in these comments is revealing; these limitations prove that the RAR does not meet the requirements of the Information Quality Act ("IQA") or DOE's guidelines thereunder.[162] The RAR should be withdrawn so that the Department does not continue to disseminate this poor-quality information, and the RAR should not be relied on in any decisionmaking. In the alternative, the Department should not use the RAR as support for any final action until and unless it (1) provides notice of the statutory authority under which DOE issued the RAR and publishes all data underlying the RAR, (2) explains in detail the specific uses for the methodology, and (3) allows interested parties to comment on the RAR before releasing a final version that incorporates and responds to public comment.

The IQA directs agencies to "ensur[e] and maximiz[e] the quality, objectivity, and integrity of information (including statistical information) disseminated by Federal Agencies."[163] Office of Management and Budget ("OMB") guidelines issued

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[159] RAR, Ex. 1 at i.

[160] *Id.*

[161] *Id.*

[162] *See* Pub. L. 106-554 Sec. 515, 114 Stat. 2763A-153.

[163] *Id.* OMB's government-wide information quality guidelines direct agencies to issue their own implementing guidelines. Agencies must provide the public a way to administratively seek and obtain correction of information disseminated by the agency that does not comply with OMB or agency guidelines. *See* Office of Management and Budget, Guidelines for Ensuring and Maximizing the Quality, Objectivity, Utility, and Integrity of Information, 67 Fed. Reg 8452 (Feb. 22, 2002); Office of Management and Budget, Memorandum for the Heads of Executive Departments and Agencies (Apr. 24, 2019) (hereinafter "OMB Guidelines 2019 Update"), https://www.whitehouse.gov/wp-content/uploads/2019/04/M-19-15.pdf.

Pursuant to the OMB directive, DOE has issued its own agency-specific information quality guidelines. *See* Dep't of Energy, Final Report Implementing Office of Management and Budget Information Dissemination Quality Guidelines (Oct. 1, 2002), no. 6450-01-p, https://www.energy.gov/sites/prod/files/cioprod/documents/finalinfoqualityguidelines03072011.pdf; Dep't of Energy, Final Report Implementing Updates to the Department of Energy's Information

pursuant to the IQA require agencies to ensure that scientific information including "factual inputs, data, models, analyses . . . related to such disciplines as . . . engineering, or physical sciences" undergo certain review procedures to maintain quality standards.[164]

To that end, agencies must "choose a peer review mechanism that is adequate, giving due consideration to the novelty and complexity of the science to be reviewed, the relevance of the information to decisionmaking, the extent of prior peer reviews, and the expected benefits and costs of additional review."[165] Agencies must "strive to ensure that their peer review practices are characterized by both scientific integrity and process integrity," including the "rationale and supportability" of the agency's findings and ensuring "avoidance of real or perceived conflicts of interest" and "a workable process for public comment and involvement."[166] Agencies are encouraged to "have the choice of input data and the specification of the model reviewed by peers before the agency invests time and resources in implementing the model and interpreting the results," in order to "focus attention on data inadequacies in time for corrections . . . before the agency becomes invested in a specific approach."[167] Additionally, peer reviewers must "ensure that scientific uncertainties are clearly identified and characterized," and "ensure that the potential implications of the uncertainties for the technical conclusions drawn are clear."[168] OMB IQA guidelines also require agencies to evaluate "the sensitivity of the agency's conclusions to analytic assumptions."[169] These steps of peer review determine a report's "fitness . . . for policy purposes."[170]

DOE IQA guidelines further note that "in disseminating certain types of information to the public, other information must also be disseminated in order to ensure an accurate, clear, complete, and unbiased presentation."[171] Agencies should provide open access to data and modeling information underlying a report.[172]

Quality Act Guidelines (2019) (hereinafter "DOE IQA Guidelines 2019 Update"), available at https://www.energy.gov/cio/articles/2019-final-updated-version-doe-information-quality-guidelines.

[164] OMB, Final Information Quality Bulletin for Peer Review, 70 Fed. Reg. 2664, 2667 (Jan. 14, 2005); *see also* OMB Guidelines 2019 Update at 4.

[165] OMB Information Quality Bulletin for Peer Review, 70 Fed. Reg. at 2668.

[166] *Id.*

[167] *Id.*

[168] *Id.* at 2669.

[169] OMB Guidelines 2019 Update at 4.

[170] *Id.*

[171] DOE IQA Guidelines 2019 Update at 16.

[172] OMB Guidelines 2019 Update at 8; *See also*, e.g., *Chem. Mfrs. Ass'n v. U.S. EPA*, 870 F.2d 177, 200 (5th Cir. 1989) ("fairness requires that the agency afford interested parties an opportunity to challenge the underlying factual data relied on by the agency."); *United States v. Nova Scotia Food*

Additionally, DOE is "responsible for ensuring that the information [being disseminated in a report] is consistent with the OMB and DOE guidelines and that the information is of adequate quality for dissemination."[173] For reports containing "influential financial, scientific, or statistical information," DOE must "identify for the [Chief Information Officer] a high ranking official" who is responsible for higher level review of the report's conclusions.[174]

OMB's IQA guidelines recognized that the "[f]ederal government's assessment of risk can directly or indirectly influence the response actions of state and local agencies or international bodies."[175] Thus, under the OMB and DOE guidelines, influential information—information routinely embargoed because of "potential effect on markets" or information "on which a regulatory action with a $100 million per year impact is based"—must meet the highest standards of quality and transparency, and should undergo the rigorous review procedures outlined above.[176]

Here, the RAR does not comply with IQA requirements, rendering any further reliance on it to be arbitrary and capricious. For example, the RAR appears to be inconsistent with internal review processes required: it should have undergone peer review because of its "influential" nature, particularly if the RAR is, as it purports to be, a "uniform methodology" to guide reliability interventions, such as Federal Power Act Section 202(c) orders, which have outsize economic impacts. However, there is no evidence that the RAR underwent any peer review, and, given the time constraints, it is unlikely it did. The Department further failed to make available all underlying data and modeling information used to create the RAR. Additionally, as described in detail below, the RAR relies on improper analytic assumptions, including overstated demand and understated supply forecasts. The RAR includes faulty analysis based on these improper assumptions despite DOE's acknowledgment of significant informational limitations regarding regional- and utility-level engineering data. In addition, the RAR contains numerous errors, such as referring to appendices that do not exist or incorrect appendices,[177] stating

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Prods. Corp., 568 F.2d 240, 251-53 (2d Cir. 1977) (holding that regulation was promulgated in arbitrary and capricious manner where agency failed to disclose data on which it relied).

[173] DOE IQA Guidelines 2019 Update at 22.

[174] *Id.* at 22-23.

[175] OMB Information Quality Bulletin for Peer Review, 70 Fed. Reg at 2667.

[176] DOE IQA Guidelines 2019 Update at 7.

[177] *See* RAR, Ex. 1, at 12 (referring to nonexistent "Outputs" section of an unnamed appendix); *id.* (referring to Appendix B for further detail regarding retirement assumptions, whereas Appendix B describes Canadian transfer limits).

inaccurate units for generation capacity,[178] and falsely asserting bulk power system load shedding occurred in regions during certain events.[179]

2. In the RAR, the Department overstates assumptions about demand.

In the RAR, the Department assumes 101 GW of load growth by 2030—a 15% increase over 2025 load. This increase is more than double the high case in the U.S. EIA 2025 Annual Energy Outlook, which forecasts 6% growth.[180] This extraordinarily high assumed load growth contributes substantially to the findings of low resource adequacy under the Plant Closures scenario in the RAR. As explained below, in the RAR, the Department omits consideration of many factors that will likely dampen load growth in the coming 5 years, thus undermining the validity and usefulness of its results.

The Department assumes 50 GW of load growth from data centers by 2030, which it characterizes as the midpoint among other available forecasts.[181] However, it does not appear that DOE's forecast accounts for load flexibility at these data centers, which would significantly reduce the overall demand that these centers place upon the grid during the periods of peak system risk. While certain data centers may not be capable of load curtailment due to their purpose, many can be flexible. Even a small amount of data center load flexibility provides significant benefits. A recent study by experts at Duke University found that curtailment at data centers during only 0.25% of the year would enable 76 GW of data center power demand to be added to the system today, without triggering resource adequacy problems or requiring further expansion.[182] The White House recently issued an AI Action Plan endorsing demand flexibility as a means to maintain resource adequacy as data center capacity expands: "the United States should investigate new and novel ways for large power consumers to manage their power consumption during critical grid periods to enhance reliability and unlock additional power on the system."[183]

The Electric Power Research Institute has begun an initiative to enhance data center flexibility in light of its benefits for grid reliability, under which

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[178] *Id.* at 9 (text stating that PJM has a shortfall of 2.4 MW).

[179] *See infra* subsection C.6.

[180] *See* GridLab Analysis, Ex. 14 at 2.

[181] RAR, Ex. 1 at 2.

[182] Norris, T. H., T. Profeta, D. Patino-Echeverri, and A. Cowie-Haskell. 2025. Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in US Power Systems at 20. Durham, NC: Nicholas Institute for Energy, Environment & Sustainability, Duke University, https://nicholasinstitute.duke.edu/publications/rethinking-load-growth (attached as Ex. 15).

[183] White House, Winning the Race: America's AI Action Plan 15 (July 2025), https://www.whitehouse.gov/wp-content/uploads/2025/07/Americas-AI-Action-Plan.pdf.

demonstration projects were set to deploy in the first half of 2025.[184] Early results from other projects to test data center flexibility have been promising.[185] Evaluations of the RAR by GridLab and the NYU Institute for Policy Integrity ("IPI") both have concluded that the Department's failure to account for data center load flexibility renders its findings of elevated reliability risk in 2030 suspect.[186] This is particularly true for DOE's findings concerning the ERCOT region, considering that in June 2025, Texas enacted a law allowing curtailment of these loads during grid emergencies.[187]

Furthermore, it is unclear whether the RAR's data center load forecasts account for potential constraints on the growth of data centers, such as shortages of critical semiconductor chips,[188] and other grid equipment like transformers and switchgears.[189] In addition to the Texas policy mentioned above, states and utilities are proposing new tariff designs for data centers to ensure that data centers don't

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[184] Elec. Power Rsch. Inst., EPRI Launches Initiative to Enhance Data Center Flexibility and Grid Reliability (Oct. 29, 2024), https://perma.cc/75LY-PSP5 ("Led by EPRI, DCFlex will coordinate real-world demonstrations of flexibility in a variety of existing and planned data centers and electricity markets, creating reference architectures and providing shared learnings to enable broader adoption of flexible operations that benefit all electricity consumers. Specifically, DCFlex will establish five to ten flexibility hubs, demonstrating innovative data center and power supplier strategies that enable operational and deployment flexibility, streamline grid integration, and transition backup power solutions to grid assets. Demonstration deployment will begin in the first half of 2025, and testing could run through 2027.").

[185] *See* Anuja Ratnayake, Unlocking AI Potential with Data Center Flexibility, ENERGYCENTRAL (June 12, 2025), https://www.energycentral.com/intelligent-utility/post/unlocking-aipotential-with-data-center-flexibility-PtPoXIAuRMzs5Ff ("In a preliminary test of the depth of computational flexibility possible in an AI data center, the Arizona demonstration site experienced some early success. It showcased the potential for an AI data center to provide grid relief during a peak system event—such as a hot summer day with high power demand—by temporarily and precisely ramping down its electricity consumption without compromising data center performance.").

[186] NYU Institute for Policy Integrity, *Enough Energy*, at 25 (attached as Ex. 16) (hereinafter "IPI Report"); *see also* GridLab Analysis, Ex. 14 at 2 ("It does not address flexibility of this load, however, which was recently demonstrated in a report from Duke University to allow for 100 GW of large load additions today with minimal grid impact.").

[187] S.B. No. 6 § 4, 89th Legislature (Tex. 2025) (to be enacted at Tex. Util. Code § 39.170), https://perma.cc/4Z7H-9XKQ; Brian Martucci, Texas Law Gives Grid Operator Power to Disconnect Data Centers During Crisis, UTILITY DIVE (June 25, 2025), https://perma.cc/SYK3-V4XX; Waleed Aslam & Robin Hytowitz, Elec. Power Rsch. Inst., Texas SB6 Explained: Addressing Large Load Impacts (2025), https://perma.cc/QD8S-3M5C.

[188] *See, e.g.* London Economics International LLC, *Uncertainty and Upward Bias Are Inherent in Data Center Electricity Demand Projections* at 39 (July 7, 2025) (attached as Ex. 17), https://www.selc.org/wp-content/uploads/2025/07/LEI-Data-Center-Final-Report-07072025-2.pdf.

[189] How big tech plans to feed AI's voracious appetite for power, The Economist (July 28, 2025), https://www.economist.com/business/2025/07/28/how-big-tech-plans-to-feed-ais-voracious-appetite-for-power.

pose risks to the distribution system or shift costs to other consumers, all of which could slow or redirect the forecasted data center load growth.[190] The Department fails to evaluate any of these dynamics in the RAR.

In addition to the overall rate of data center load growth, the Department also uses a poorly described and supported methodology to allocate data center load to different regions. As the IPI observes, DOE used state-level growth ratios to allocate the projected data center load across regions, "[b]ut it is unlikely that all the computing demand needs to be processed close to load centers (i.e., proportional to a region's current electric load)."[191] IPI posits that "some computing demand may be served from other regions if it will be cheaper to integrate the data center elsewhere," and observes that "[g]iven the scale of DOE's projected data center load compared to the relatively small resource adequacy shortfalls that the study identifies, these assumptions may have made the difference between whether a region achieves DOE's resource adequacy targets."[192] Figure 8 in the RAR (New Data Center Build) shows that DOE's estimates for the percentage of data center load growth that will be built in various RTOs in some cases differs substantially from the percentages in the various forecasts that DOE used to calculate its overall data center load growth estimate. DOE does not explain why it discards these studies' more geographically specific estimates and instead relies on a single state-level growth ratio derived from a different study.

The Department's approach to estimating non-data center load growth by 2030 is also poorly explained in the RAR and likely flawed. DOE relies upon NERC's 2024 Long-Term Reliability Assessment forecast for overall load growth, but because the Department otherwise seeks to include elevated levels of data center load growth in the RAR, it must back out an estimate of data center load growth from the overall forecast.[193] The estimate that DOE chooses to back out is a "low-growth" case for data center load from a different source (which DOE presents in volumetric consumption terms, rather than peak demand). This approach, without further information to understand DOE's analysis, could have resulted in DOE over-estimating non-data center load growth. This effect is likely exacerbated by recent changes in federal law that will reduce electricity consumption from

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[190] Jason Plautz, *Rulemakers play catch-up as data centers multiply*, E&ENews by Politico (July 18, 2025), https://www.eenews.net/articles/rulemakers-play-catch-up-as-data-centers-multiply/.

[191] IPI Report, Ex. 16 at 26.

[192] *Id.*

[193] RAR, Ex. 1 at 17 ("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 [Long-Term Reliability Assessment] forecast, for example, the 2024 [Long-Term Reliability Assessment] 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.").

specific sectors, including vehicles and hydrogen electrolysis. The utility forecasts included in the NERC Long-Term Reliability Assessment included projections of vehicle and building electrification that depend in part on tax credits and incentives that were revoked prior to publication of the RAR as part of the One Big Beautiful Bill Act ("OBBBA"). Recent analysis shows that the elimination or reduction of tax credits that supported new sources of electricity load growth will have a meaningful effect by 2030.[194] As a result, DOE's non-data center load growth projections are likely overstated.

3. Assumptions about supply are unsupported.

a. In the RAR, the Department Overstates Likely Retirements.

The Department finds the most dire resource adequacy shortfalls occur in the Plant Closures case, in which it assumes 104 GW of retirements by 2030.[195] This estimate is much higher than the most recent data from the EIA released in June 2025 in its authoritative Form 860, which shows 50 GW fewer retirements than assumed in the RAR.[196] As GridLab experts explained, DOE assumed not only "these 50 GW of likely retirements, but [also] included another 50 GW of *announced* retirements."[197] While it may be appropriate to include announced retirements in certain long-term planning exercises, it is unreasonable to assume such retirements will happen as the basis for extraordinary emergency actions. Without more detail about any formal or binding characteristics of those announcements, or the factors purportedly driving those announcements, it is impossible to verify the validity of this input that doubles the amount of otherwise projected resource retirements. Even EIA's Annual Energy Outlook, which does model projected retirements beyond those already formally noticed, finds 10 GW fewer thermal retirements by 2030 than does DOE.[198] Without further support for the 50 GW assumed retirement

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[194] *See, e.g.,* Princeton NetZero Lab and Evolved Energy Research, A Fork in The Road: Impacts of Federal Policy Repeal on the U.S. Energy Transition, at Tab 12 (last updated July 3, 2025), https://public.tableau.com/app/profile/evolvedenergyresearch/viz/AForkinTheRoad_ImpactsofFederalPolicyRepealontheU_S_EnergyTransition_June/1Title (showing approximately 100 TWh annual energy use reduction in 2030 compared to mid-range estimates of the status quo ante).

[195] RAR, Ex. 1 at 5.

[196] U.S. EIA, Annual Energy Outlook 2025: Table 9. Electricity generating capacity (March 2025), https://www.eia.gov/outlooks/aeo/data/browser/#/?id=9-AEO2025&region=0-0&cases=ref2025&start=2025&end=2030&f=A&linechart=ref2025-d032025a.4-9-AEO2025&map=&sourcekey=0. *See also* GridLab Analysis, Ex. 14 at 2.

[197] GridLab Analysis, Ex. 14 at 2; *see also* IPI Report, Ex. 16 at 24 (explaining that DOE's "number includes both 'confirmed' retirements—resources that have notified their system operators of their impending retirements and begun the retirement process—and 'announced' retirements—which are publicly stated but not officially noticed.").

[198] According to the U.S. EIA's 2025 Annual Energy Outlook, coal-fired generating capacity is projected to decline by 93.6 GW between 2025 and 2030 in the Reference case, approximately 10

value, the Plant Closures case is nothing more than speculation about what might happen if certain assumptions were to come true.

Such assumptions are particularly unjustified given that, as GridLab notes, "[m]ost likely many plants will choose not to retire due to the changing regulatory and economic landscape."[199] The IPI makes a similar point in their critique of DOE's retirement assumptions, noting that "the economics of energy production have changed since 2024. The combined effect of new demand from data centers and the elimination of federal tax credits for new wind and solar resources improves the financial outlook for thermal resources."[200] As one snapshot of this trend, high capacity prices in the PJM region led to 1.1 GW of resources withdrawing formal deactivation notices since last summer.[201] IPI also observes that the Trump Administration is seeking to rescind or reexamine many federal environmental regulations that would have required thermal resources to make investments reducing their pollution or else retire before 2030, "which could cause resources to delay their retirements."[202]

b. In the RAR, the Department Understates Likely New Entry by 2030 and Other Sources of Supply.

Among the most impactful and unsupported assumptions in the RAR is that "only [generation] projects that are very mature in the pipeline (such as those with a signed interconnection agreement) will be built" by 2030.[203] DOE thus constrains its analysis to include only projects designated as Tier 1 in the NERC 2024 Long Term Resource Assessment, which it then maps to Interregional Transfer Capability Study regions. Because Tier 1 includes only resources that are already under construction, have signed construction service agreements, and similar

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fewer GW of retirements than modeled in the DOE report. No other fossil fuel technology shows a net decrease in generating capacity in the 2025 Annual Energy Outlook analysis. U.S. EIA, Annual Energy Outlook 2025: Table 9. Electricity generating capacity (March 2025), https://www.eia.gov/outlooks/aeo/data/browser/#/?id=9-AEO2025&region=0-0&cases=ref2025&start=2025&end=2030&f=A&linechart=ref2025-d032025a.4-9-AEO2025&map=&sourcekey=0.

[199] GridLab Analysis, Ex. 14 at 2.

[200] IPI Report, Ex. 16 at 24.

[201] PJM Inside Lines, PJM Auction Procures 134,311 MW of Generation Resources; Supply Responds to Price Signal (July 22, 2025) https://insidelines.pjm.com/pjm-auction-procures-134311-mw-of-generation-resources-supply-responds-to-price-signal/ ("Since the 2025/2026 Base Residual Auction results were posted on July 30, 2024, 17 generating units totaling approximately 1,100 MW worth of Capacity Interconnection Rights have withdrawn their retirements").

[202] IPI Report, Ex. 16 at 24-25.

[203] RAR, Ex. 1 at 12.

characteristics,[204] this assumption "results in minimal capacity additions beyond 2026."[205] As experts at GridLab observe, the assumption that "no projects are built post 2026, [] is not realistic for a report forecasting to 2030."[206] This is especially true given rising energy prices due to increased demand, which is attracting more investment to the market and driving new construction of generation resources.

The Department also states in the RAR that of these Tier 1 additions, just 22 GWs of generator additions are "firm" (thermal) resources, which severely underestimates new gas generation compared to other projections. According to GridLab, "a more reasonable assumption for forecasted capacity additions is the EIA 860 released in June 2025, which has 35 GW of gas additions, and another 53 GW of batteries [for a total of] 88 GW of firm additions by 2030."[207] Other federal government projections are even higher: EIA's 2025 Annual Energy Outlook projects 90 GWs of new fossil generators added to the system through 2030.[208] 80 GWs of the EIA-projected natural gas growth are in earlier development stages and likely did not meet the 2024 NERC Long-Term Reliability Assessment Tier 1 criteria to be included in the RAR.

As researchers at the IPI conclude, DOE departed from best practice in declining to include any resources classified by NERC as "Tier 2" resources[209] in the overall resource adequacy analysis for 2030, even those at advanced stages of the interconnection process.[210] A reasonable process could have involved "examin[ing]

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[204] *See* IPI Report, Ex. 16 at n.155 (citing NERC, 2024 Long Term Reliability Assessment, 137 (last updated July 15, 2025) https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf).

[205] RAR, Ex. 1 at A-5.

[206] GridLab Analysis, Ex. 14 at 3.

[207] *Id.*

[208] According to the U.S. EIA, the policy-neutral reference case projects a 93.29 GW increase in combined cycle, fossil steam, and combustion turbine capacity between 2025 and 2030. U.S. EIA, Annual Energy Outlook 2025: Table 9. Electricity generating capacity (March 2025), https://www.eia.gov/outlooks/aeo/data/browser/#/?id=9-AEO2025&region=0-0&cases=ref2025&start=2025&end=2030&f=A&linechart=ref2025-d032025a.4-9-AEO2025&map=&sourcekey=0.

[209] NERC defines Tier 2 resources as those having one of the following characteristics: "Signed/approved Completion of a feasibility study, Signed/approved Completion of a system impact study, Signed/approved Completion of a facilities study, Requested Interconnection Service Agreement, Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to RTOs/ISOs)." NERC, 2024Long Term Reliability Assessment, 137 (Dec. 2024, updated July 15, 2025) https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

[210] IPI Report, Ex. 16 at 23.

historical statistics of interconnection queue time by region, resource type, and resource size, along with differentiated queue withdrawal rates, estimating Tier 2 resource additions for each region."[211] For example, for the PJM region, the Independent Market Monitor's analysis shows that 15% of generation projects (on an energy basis) successfully enter service.[212] As of late 2024, PJM had over 44 GW of accredited capacity in its interconnection queue.[213] To assume that none of this capacity would enter service by 2030, as DOE's analysis does, is unreasonable.

Such an analysis should also consider factors pointing towards even faster queue times than those seen in the historical data, given factors now expediting interconnection queues such as implementation of FERC Order 2023, streamlining of tools to better utilize existing points of interconnection (e.g., surplus interconnection service), and various interconnection fast tracks that FERC has recently approved.[214] For example, it is unreasonable for DOE to exclude from consideration the over 9 GW of accredited capacity that PJM selected in May 2025 to participate in its Reliability Resource Initiative—the vast majority of these projects (primarily gas and battery energy storage systems) are committed to be online by 2030,[215] but are omitted in DOE's analysis because they do not yet have a signed interconnection agreement. DOE paints an inaccurate picture of new entry by ignoring recently adopted policies designed to address the very same tightening supply and demand conditions that DOE describes.

DOE also underestimates the extent to which interregional transfers of energy could help to prevent or address any shortfalls. Noting that it relies upon the interregional transfer capacities identified by NERC in its Interregional Transfer Capability Study, DOE explains that "[i]mports are assumed to be available up to the minimum total transfer capacity and spare generation in the

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[211] *Id.*

[212] Monitoring Analytics, 2024 State of the Market Report, at 705 (2024) https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2024/2024q2-som-pjm-sec12.pdf (noting 14.9% completion rate).

[213] PJM, Reliability Resource Initiative MRC Update, at slide 6 (Nov. 7, 2024) https://www.pjm.com/-/media/DotCom/committees-groups/committees/mrc/2024/20241107-special/item-04---reliability-resource-initiative---presentation.ashx.

[214] *Id. See also* Prefiled Statement of Manu Asthana on Behalf of PJM Interconnection, L.L.C., FERC Docket No. AD25-7, at 4 (May 27, 2025), https://www.ferc.gov/media/manu-asthana-pjm-president-and-ceo (touting recent improvements to PJM's interconnection queue by noting that "[a]n additional approximately 18 GW is being processed to move to the final study phase for completion this year, and an additional 56 GW (including projects from Transition Cycle 2 and Reliability Resource Initiative) will be through the queue by late 2026.").

[215] PJM, Reliability Resource Initiative Results Summary, at slide 9 (May 6, 2025) https://www.pjm.com/-/media/DotCom/committees-groups/committees/pc/2025/20250506/20250506-item-06---reliability-resource-initiative---summary-results.pdf.

neighboring subregion."[216] Because the Interregional Transfer Capability Study calculated interregional transfer capacities for both summer and winter, and for each direction of flow, it is unclear what DOE means regarding allowing transfers up to the minimum. As the IPI observes: "If DOE picked the lesser of the summer and winter transfer capacities and applied that annually, doing so would inaccurately underestimate the amount of interregional transfer capacity."[217] This is yet another example of where DOE fails to explain its methodology with sufficient detail to enable an evaluation of whether its approach is reasonable, or is supported by substantial evidence.

4. DOE's use of a deterministic analysis provides an incomplete and inaccurate picture.

For the RAR, DOE employs a deterministic approach in examining resource adequacy; that is one that "evaluate[s] resource adequacy using relatively stable or fixed assumptions about the representation of the power system," rather than a probabilistic approach that "incorporate[s] data and advanced modeling techniques to represent uncertainty that require more computing power."[218] DOE explains it chose a deterministic approach "for transparency and to model detailed historic system conditions."[219] However, deterministic approaches have significant limitations; as NERC explained in the Interregional Transfer Capability Study on which DOE otherwise heavily relies, because that study did not employ a probabilistic approach, it "should not be considered a North American resource adequacy assessment."[220] The problem, as IPI explains, is that "[b]y examining whether regions would be resource adequate only under conditions that resemble the recent past, DOE's study does not sufficiently account for uncertainty."[221] Furthermore, as NERC itself has explained, under a deterministic approach, "some regions may look resource adequate because they happened to do well during the twelve years of data, while others look resource inadequate but be unlikely to perform as poorly in the future."[222] As IPI concludes, neither of DOE's professed reasons for using a deterministic approach justifies departing from best practices, as "DOE could document a probabilistic approach in a transparent way, and relying on a small sample of historic years is less accurate than a probabilistic approach."[223]

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[216] RAR, Ex. 1 at 12.

[217] IPI Report, Ex. 16 at 26.

[218] RAR, Ex. 1 at 2 n.2.

[219] *Id.*

[220] IPI Report, Ex. 16 at 21 (citing NERC, Interregional Transfer Capability Study, at 4 (2024) (hereinafter "NERC ITCS")).

[221] IPI Report, Ex. 16 at 21.

[222] *Id.* (citing NERC ITCS at 138).

[223] *Id.* at 21.

DOE may have chosen a less sophisticated and rigorous approach given the limited amount of time in which the Grid EO required this analysis to be completed, but regardless of the reason, the limitations inherent in DOE's deterministic methodology mean that its findings should not be taken as conclusive or form the basis for further extraordinary actions.[224]

5. DOE uses an elevated threshold for determining when outages will occur.

In the RAR, the Department projects a shortfall if "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."[225] This approach, and the particular values used as thresholds, come from the NERC Interregional Transfer Capability Study, which uses 3% as the default threshold and 6% only in a sensitivity analysis. NERC explains that the 3% value "was established based on an evaluation of average reserve requirements where load shed may occur" in order for a Balancing Authority to continue to hold the minimum reserves needed to protect the system from cascading or widespread outages.[226] In the sensitivity examined by NERC, using the 6% threshold "significantly altered the existence and extent of predicted outages in many regions, such as producing a 690% increase in the size of the maximum outage event in SERC-Florida."[227]

As the IPI analysis notes, DOE provides no further explanation for when and how it uses 6% as a threshold versus 3%.[228] While the Department directs readers to an appendix with further detail, the appendices do not in fact provide any further information regarding this critical assumption.[229] Furthermore, "the fact that DOE listed 6% first may suggest that 6% was not limited to a sensitivity analysis," and that if "DOE's model instead identifies shortage events even when a region still has 6% of load available as spare capacity, then DOE's results depart from NERC's practice and may overstate the extent of expected outages."[230] DOE's failure to explain its own methodology concerning such a critical input to its analysis, including through the failure to provide information in an appendix that the RAR states exists, renders the RAR arbitrary and capricious. Insofar as the RAR's results for 2030 scenarios depend upon the 6% threshold, DOE must explain why

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[224] *Id.* ("Given the high stakes associated with resource adequacy planning, any future DOE resource adequacy assessment should prioritize accuracy over expediency.")

[225] RAR, Ex. 1 at 12.

[226] IPI Report, Ex. 16 at 22 (citing NERC ITCS, at 91 n.90, 85).

[227] IPI Report, Ex. 16 at 22 (citing NERC ITCS at 105 tbl.8.4); *see also id.* ("Under the 6% sensitivity, NERC also recommended 58 GW of transmission additions to address resource adequacy instead of 35 GW, illustrating the sizable influence of shifting this assumption from 3% to 6%.")

[228] IPI Report, Ex. 16 at 22.

[229] *Id.*

[230] *Id.*

such a threshold is appropriate, given the departure from NERC's practice and the evidence in the NERC report considering the propriety of a far lower threshold.

6. DOE inconsistently applies its own methodology.

Several of the findings in the RAR are inconsistent with the methodology that DOE develops. For instance, DOE states that "[a]nalysis 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" (the standards DOE developed for this study).[231] DOE further explains that "[w]hen 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."[232] Despite these clear findings, DOE goes on to state that "PJM, ERCOT, 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," and asserts that this "results in a concentration of lost load within certain years such that some regions exceeded 3-hours-per-year of lost load."[233] As an initial matter, the PJM system did not experience any lost load due to resource inadequacy during Winter Storms Uri or Elliott.[234] Second, DOE's focus on whether a region had lost load or a risk of lost load in a particular weather year is inconsistent with DOE's own articulation of its resource adequacy standards, as "average indicators" assessed across all scenarios and years.[235] As the IPI notes, these standards are "not a requirement that must be achieved in each and every scenario."[236]

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[231] RAR, Ex. 1 at 7.

[232] *Id.*

[233] *Id. See also Id.* at 9 ("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.").

[234] PJM Inside Lines, PJM Releases Winter Storm Elliott Report (July 17, 2023) https://insidelines.pjm.com/pjm-releases-winter-storm-elliott-report/ ("PJM maintained system reliability and served customers throughout the extreme weather that affected the region Dec. 23–25 [2022], and even was able to support its neighbors during certain periods."); *see also* FERC, NERC and Regional Entity Staff Report, *The February 2021 Cold Weather Outages in Texas and the South Central United States* (Nov. 16, 2021), https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and (noting that PJM was exporting power to neighboring regions during Winter Storm Uri, and investigating rolling blackouts only in Texas and south central states).

[235] RAR, Ex. 1 at 5.

[236] IPI Report, Ex. 16 at 20.

D. Notice and Comment Procedures Are Required for Any "Uniform Methodology" the Department Uses to Guide Reliability Interventions.

Under the Administrative Procedure Act, federal agencies must provide notice and an opportunity for public comment when issuing rules, with limited exceptions not applicable here.[237] If the RAR is, as the Department claims on page vi, a "uniform methodology" for agency decisionmaking on reliability interventions, then the Department needed to provide notice and seek and respond to public comment on this methodology. The Department cannot slip in "entirely new information critical" to its "determination[s]" without taking and responding to public comment.[238]

In the past, when the Department sought to create uniform triggers for reliability intervention within its authority, it issued notice and sought comment.[239] If the RAR is a "uniform methodology" for reliability interventions, then the Department has effectively amended those prior regulations on reliability interventions without following legally required procedures. For example, the Department has regulations defining "emergency" and setting forth procedures for an applicant to demonstrate an "emergency" in the context of Federal Power Act Section 202(c) orders.[240] If the RAR is now a mandatory factor in determining whether there is an "emergency," the Department has changed its existing regulations without following required notice and comment procedures.

E. NEPA Procedures Must Be Followed for Any RAR on Legislative Proposals or "Uniform Methodology" the Department Uses to Guide Reliability Interventions.

Under the National Environmental Policy Act ("NEPA"), agencies must include a "detailed statement" on the environmental impacts of a proposed action "in every recommendation or report on proposals for legislation and other major Federal actions significantly affecting the quality of the human environment."[241] If the RAR is a "uniform methodology" for agency decisionmaking on reliability interventions, it qualifies as a major federal action requiring, at a minimum, an Environmental Assessment and most likely, under the circumstances, a full

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[237] 5 U.S.C. §§ 553(b), (c).

[238] *Am. Pub. Gas Assoc. v. DOE*, 72 F.4th 1324, 1338 (D.C. Cir. 2023) (cleaned up).

[239] *See* Grid Security Emergency Orders: Procedures for Issuances, 83 Fed. Reg. 1174 (Jan. 10, 2018) (final rule on Federal Power Act section 215A procedures issued after notice and comment); Emergency Interconnection of Electric Facilities and the Transfer of Electricity to Alleviate an Emergency Shortage of Electric Power, 46 Fed. Reg. 39,984 (Aug. 6, 1981) (final rules concerning emergency interconnections under Federal Power Act sections 202(c) and 202(d) issued after notice and comment).

[240] 10 C.F.R. §§ 205.371; 205.373.

[241] 42 U.S.C. § 4332(C).

Environmental Impact Statement. However, the RAR does not contain any statement whatsoever, and certainly no "detailed statement," on environmental impacts.

Yet the RAR purports to guide "government decisionmakers" on one of the most significant issues that affect the environment—electricity generation. The electricity sector is responsible for wide-ranging environmental impacts—from smog to greenhouse gas emissions to toxic metals to acid rain.[242] Uniform rules on reliability interventions would significantly affect the environment because some of these reliability interventions allow environmental rules for electricity generators to be waived.[243]

VI. CONCLUSION

For the reasons set forth above, the undersigned Public Interest Organizations respectfully request that the Department withdraw the RAR. In the alternative, the Department should not use the RAR as support for any reliability intervention or other action until and unless it (1) provides notice of the statutory authority under which DOE issued the RAR and publishes all data underlying the RAR, (2) provides a detailed explanation of the specific uses for the methodology, and (3) allows interested parties to comment on the RAR before finalizing it.

Dated: August 8, 2025

Respectfully submitted,

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[242] *See* EPA, Human Health & Environmental Impacts of the Electric Power Sector (Feb. 6, 2025) https://www.epa.gov/power-sector/human-health-environmental-impacts-electric-power-sector.

[243] *See* 16 U.S.C. § 824a(c)(4)(A).

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-7

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

Filed September 5, 2025

Exhibit 100

Curran Testimony

Testimony of Jennifer Curran

Senior Vice President, Planning and Operations

Midcontinent Independent System Operator, Inc. (MISO)

Before the House Committee on Energy and Commerce,
Subcommittee on Energy

" Keeping the Lights On: Examining the State of
Regional Grid Reliability."

March 25, 2025

Executive Summary

Today, several factors produce rising electricity resource adequacy and reliability concerns across the country, creating a complex policy landscape:

- Growing electric demand from continued electrification, a resurgence in manufacturing, and energy-hungry data centers to support artificial intelligence.
- The accelerated early retirement of existing electric generation.
- The growing preference for low or no carbon emission resources that often do not have the 24/7 availability, flexibility, and duration attributes of the power plants they are replacing.
- More frequent occurrences of extreme weather, particularly winter storms affecting large areas of the country, are creating challenging operating conditions.

For several years, MISO has been taking action through its ongoing Reliability Imperative initiative to help address these growing challenges. For example:

- Electric resource accreditation reforms to better identify a resource's ability to perform during hours of highest risk and updated real-time pricing signals to better incentivize availability during tight operating conditions.
- Over $30 billion in new transmission lines to substantially improve electric transfer capabilities and ensure electric reliability and associated economic growth.
- Improvements to the generator interconnection queue process to expedite the approval of new electric generation on the system.

More work remains to be done to ensure that our nation's bulk electric system remains reliable:

- Let reliability needs help inform the pace of retirement of existing electric generating resources, ensuring they aren't retired before adequate new electric generation is available.
- Continue developing new electric generation resources and transmission projects at a rapid pace; mitigate the regulatory, supply chain, and other challenges that hinder development.
- Leverage an approach that includes a mixture of present and new thermal resources as well as solar, wind, storage, emerging technologies, and transmission to achieve reliability.
- Support reforms, like MISO's Expedited Resource Adequacy Study and Demand Response and Emergency Resource reforms, that enhance the utilization of existing resources.

Introduction

Good morning Committee Chairman Guthrie, Ranking Member Pallone, Subcommittee Chairman Latta and Ranking Member Castor, and members of the Subcommittee. I am Jennifer Curran, Senior Vice President of Planning and Operations for the Midcontinent Independent System Operator (MISO). It is a pleasure to be here today as you consider the state of regional grid reliability and its impact on our nation. I hope MISO's insights and experience will be useful to your work of shaping U.S. energy policy.

MISO Overview

Before I share MISO's insights on some of the challenges facing our nation's bulk electric system and MISO's work to stay a step ahead of these challenges, I would like to provide a brief overview of MISO and our work.

MISO is a 501(c)(4) not-for-profit social welfare organization with an obligation to act in the public interest. MISO is responsible for ensuring the reliability of the high-voltage electric transmission system to deliver low-cost wholesale energy to consumers. The Federal Energy Regulatory Commission's (FERC) Order 2000 established Regional Transmission Organizations (RTOs), like MISO, to be independent entities that plan and operate the electric grid on a regional basis to maintain reliability and maximize efficiency. MISO was the first Independent System Operator to be recognized as an RTO, receiving FERC approval in 2001.

The wholesale electricity markets MISO manages are the largest in North America in terms of geographical scope, serving about 45 million people across all or parts of 15 states, stretching from the Canadian border to the Gulf Coast. The pricing rules in the MISO market are designed to reinforce the reliable operations of the bulk electric system. MISO's energy markets are also among the largest in the world, with more than 550 market participants and $40 billion in annual gross market charges. MISO also serves as the reliability coordinator for the Canadian province of Manitoba.

Currently, the MISO market region contains about 77,000 miles of high-voltage transmission lines and 203 gigawatts of electric generating capacity. MISO does not own any of these assets. Instead, with the consent of our 223 members and in accordance with our FERC-regulated tariff, MISO exercises functional control over the region's transmission and generation resources with the aim of utilizing them to ensure reliability in the most cost-effective manner possible. MISO has a robust and strong stakeholder process that allows asset owners, state regulators, load-serving entities, and end-use customers to provide input and guidance to MISO on a regular and ongoing basis.

The MISO region predominantly consists of vertically integrated utilities with responsibility for providing adequate electric generation to meet needed load for their area and states having jurisdiction over electric resource adequacy decisions. This is distinct from many other RTOs, which rely more heavily on competitive markets to shape electric resource adequacy needs. MISO works with the states, utilizing its regional perspectives and insights, to ensure they have an understanding of evolving system needs and conditions.

MISO puts a priority on maintaining our independence from individual market participants. We are fuel source and policy neutral, meaning we do not favor, prefer, or advocate any particular fuel or policy outcome. That doesn't mean, however, that we are disinterested observers. Our mission is to ensure the continued reliability of the bulk electric system.

MISO also creates significant value for the region, which is quantified in the MISO Value Proposition study. Our work to maintain reliability, administer wholesale markets and conduct transmission planning on a regional scale generates substantial benefits. In 2024 alone MISO created approximately $5.1 billion in savings for the region, and over $50 billion since 2007. Ultimately, this results in lower costs to consumers.

Electric System Challenges

Electricity plays a vital role in the lives of all Americans, and its importance is continuously growing. To ensure that our nation's bulk electric system remains reliable in our ever-changing world, it is important to recognize and stay ahead of the challenges and trends that could impact

electricity. Today, the MISO region faces resource adequacy and reliability challenges due to the changing characteristics of the electric generating fleet, inadequate transmission system infrastructure, growing pressures from extreme weather, and rapid load growth.

Driven by a combination of state and federal policies and consumer demand for carbon free energy, the MISO region is experiencing a rapid growth of wind and solar energy accompanied by the retirement of many coal and natural gas power plants. While weather-dependent resources like solar and wind are being added in large numbers and provide many benefits, including lower electricity production costs than natural gas or coal and lack of carbon emissions, they typically do not provide the 24/7 availability, flexibility, and duration attributes of the retiring power plants they are replacing. For example, MISO has experienced 11 wind droughts – extended periods of time with extremely low wind output – since 2020, including one lasting 40 consecutive hours. Similarly, solar output is dramatically reduced in overcast or cloudy weather conditions, as often occur in winter storms, and output is virtually zero in the overnight hours.

In order to understand potential impacts of a changing generation mix, MISO compiles our individual member plans and state policies. MISO then uses this information to develop a range of expected outcomes we call Future Planning Scenarios. MISO's Future Planning Scenarios estimate that while the total amount of installed electric generation will increase significantly over the next 20 years due to the rapid growth of wind and solar, the actual amount of electricity available to the system during critical hours could decline by about 32 GW due to the operational characteristics of these new resources. Emerging technologies with the needed characteristics, such as longer-duration battery storage and small modular nuclear reactors, hold great promise in the future but are likely years away from grid-scale viability.

We must also recognize that the existing electric transmission infrastructure is inadequate to meet future needs. It cannot carry the amount of energy that will be needed in future years, nor does it provide the connectivity to move energy from increasingly widespread generation fleets to population centers. It is notable too that approving and building new high-voltage transmission lines is a complex and lengthy process.

MISO's region, like most of the country, is also experiencing changing weather patterns, including more frequent occurrences of extreme weather, particularly winter storms affecting large areas of the country. These extreme weather events create challenging operating conditions, with high demand for electricity sometimes accompanied by reduced solar or wind output and, in some instances, challenges with adequate fuel supplies for natural gas and coal power plants. This highlights the need for a diverse electric generation fleet and a robust transmission system to move energy over long distances.

Finally, demand for electricity is growing at an accelerated pace. Over the last few decades, we have experienced growth in electrification through electronic devices, smart home products, and electric vehicles, but minimal growth in electric demand, largely due to increasing energy efficiency. Looking ahead, however, we expect much stronger growth from continued electrification efforts, a resurgence in manufacturing, and an unexpected demand for energy-hungry data centers to support artificial intelligence. In fact, based on the current trajectory, electric load in the MISO region is projected to grow by approximately 60% over the next 20 years, threatening to outpace new electric resource additions if urgent action isn't taken.

This combination of factors significantly increases operational challenges, uncertainty, and reliability risks to the electric grid. This, in turn, creates significant economic and security risks for our nation. If electricity production and delivery from all sources cannot keep up with growing demand, then the planned growth of manufacturing, artificial intelligence, and data centers cannot occur. A timely and coordinated approach is necessary if we are to continue meeting the nation's need for reliable and low-cost electricity.

Opportunities and Work-in-Progress

MISO continuously works with its members and states to gain a more accurate understanding of future electricity needs and timelines. Two of our most important tools are the Futures Planning Scenarios, which are MISO projections capturing a range of potential system conditions over a 20-year horizon, and the annual Organization of MISO States and MISO survey, a voluntary survey of generation owners to assess available resource capacity to serve the projected load over the next five years. These regularly updated studies provide the basis for long-term transmission

planning efforts and help inform the electric resource planning decisions, which are the purview of the states and utilities in the MISO region.

MISO's extensive analysis and operational experience make it clear that no single electric generating resource, transmission line, process improvement, emerging technology, or other solutions will solve all our challenges. Addressing our nation's future electricity needs requires a multi-faceted and coordinated approach that leverages all of these tools.

Improving existing market and operations processes and tools is a cost-effective and timely way to improve reliability in an efficient manner. Over the last few years MISO instituted, with FERC approval, electric resource accreditation reforms to better identify their ability to perform during hours of highest risk, and recently submitted a filing to update its shortage pricing to better incentivize electric resource availability during tight operating conditions. Looking ahead, MISO is currently working with its stakeholders to update the framework governing the usage of Demand Response and Emergency Resources to improve the ability of those existing entities to support system reliability during challenging operating conditions.

Other efforts include working to maximize electric flows on existing transmission lines, which can be enabled by utilizing certain grid-enhancing technologies, like advanced line ratings, that provide more accurate real-time data on the amount of electricity that can safely be transmitted without overheating a power line.

A substantial amount of new electric generation is also needed to help meet future electricity needs. While MISO supports the work of developers to continue accelerating the advancement of solar, wind, and emerging technologies, there is also a need to maintain existing and add new natural gas resources to provide flexibility and duration characteristics, thus serving as a reliability insurance policy for periods when electric demand is high and weather conditions aren't conducive to adequate solar and wind output. A growing reliability risk is that the rapid retirement of existing coal and gas power plants threatens to outpace the ability of new resources with the necessary operational characteristics to replace them. This can be addressed by letting local reliability requirements determine the pace of retirement of existing power plants. Having

the right mix of resources on the system means that we don't have to choose between decarbonization and reliability.

To ensure the necessary generation is there when needed, MISO is also working to improve the efficiency and timeliness of approving new electric generator interconnections. Currently, MISO's generator interconnection queue faces a significant backlog, with over 1,600 projects totaling over 296 GW of installed capacity currently under review. For comparison, MISO's region currently has less than 1,500 generating units and peak electric load in 2024 was 122 GW. While history has shown that not all projects submitted into the queue will be built, they all must be studied for potential system impact. Currently, queue cycles are taking three to four years, as a dramatic growth in the number of project requests in recent years has exponentially increased the difficulty of the detailed studies that must be conducted. MISO has instituted several reforms to speed up the queue cycles, including a cap on the number of projects that can enter the queue in a given cycle, and is working on several technology enhancements and process improvements to eventually get to a one-year queue cycle. In the interim, an Expedited Resource Addition Study process was recently submitted for FERC for consideration. If approved, this process would provide a temporary framework, sunsetting by the end of 2028, for the accelerated study of electric generation projects that are required to address urgent resource adequacy and reliability needs. A second challenge is the long timeline required for approved electric generation projects to be built and connected to the system. Currently, the MISO region has over 53 GW of projects that have been approved but are not yet operational, and project developers have indicated that more than half of those are delayed, often due to regulatory hurdles, supply chain challenges, and labor shortages.

As electric demand grows and electric generation shifts from large power plants to more dispersed solar and wind facilities, there is also a need for significant expansion of high-voltage transmission lines. To that end, over the last several years MISO has approved over $30 billion in new transmission lines through its Long-Range Transmission Planning efforts, with more expected in the coming years. These projects are projected to have a benefit-to-cost ratio of approximately 2.6 to 1 and will substantially improve electric transfer capabilities and enable the electric reliability and associated economic growth being planned across the nation.

Interregional collaboration with neighboring grid operators – including SPP, PJM, and TVA – is also a vital tool for meeting demand for electricity. MISO and our neighbors have various operating agreements and communications protocols in place to help support one another, as feasible, for both economic and reliability purposes. Additionally, MISO and SPP have collaborated on a Joint Targeted Interconnection Queue that includes five transmission projects along the shared border that is expected to enable 28 GW of new electric generation, providing reliability and economic benefits to both regions.

Looking Ahead

The operational challenges and reliability risks of the MISO region are largely mirrored across the country. To address them, we need to take several important steps to turn around the decline in available energy and to expedite the construction of new electric generation and the transmission lines necessary to move necessary energy from where it is produced to where it is needed. Specifically:

- A strong, working Federal Energy Regulatory Commission is vital to furthering policies and supporting reforms necessary to ensure a stable and reliable electric system.

- Ensure that states and utilities have the information they need to make prudent electric resource decisions to support resource adequacy.

- Let reliability needs help inform the pace of retirement of existing electric generating resources, ensuring they aren't retired before adequate new electric generation is available.

- Continue developing new resources at a rapid pace. Streamline the approval of new electric generation and transmission projects, and work to mitigate the regulatory, supply chain, and workforce challenges that can hinder development of these projects.

- Leverage an "all of the above" approach that includes a mixture of solar, wind, natural gas, storage, emerging technologies, and transmission to achieve reliability.

- Support reforms, like MISO's Expedited Resource Adequacy Study and Demand Response and Emergency Resource reforms, that enable the more effective and efficient utilization of existing resources and capabilities.

- Continue to support and encourage interregional collaboration on future transmission needs and operational protocols that maximize the use of the existing system.