Planning Year 2026-2027 Loss of Load Expectation Study Initial Report

The Planning Year 2026-2027 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 (CIL/CEL) values.

Highlights

- For Planning Year 2026-2027, the Planning Reserve Margins (PRM) are as follows, Summer (7.9%), Fall (11.6%), Winter (18.9%), and Spring (23.4%).

- The LOLE study indicated a partial shift in annual risk from the Summer to the Winter season, a new development when compared to previous years' analyses.

- Increases in load forecasts and a significant volume of new solar resources were the primary driving factors for change. Additionally, shifting risk hours and ongoing enhancements to better represent correlated extreme cold weather forced outages impacted this year's results.

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Executive Summary

Each year, in compliance with Module E-1 of its Tariff, MISO performs its annual Loss of Load Expectation (LOLE) study to prepare for the Planning Resource Auction's (PRA) upcoming Planning Year (PY). MISO's LOLE analysis for the 2026-2027 Planning Year reflects the organization's continued commitment to reliability, transparency and continuous improvement. Building on lessons learned from prior cycles, MISO has proactively enhanced its LOLE methodology and quality assurance processes to ensure the most accurate and dependable assessment of system risk. These enhancements include refined modeling of storage and demand response, improved cold weather outage profiles, and validation of model inputs and outputs.

The study determined Planning Reserve Margins (PRMs) and Local Reliability Requirements (LRR) that will be used for the PRA. PRMs are used to calculate seasonal capacity requirements, and the Local Reliability Requirement (LRR) for each Local Resource Zone (LRZ) are used to determine the Resource Adequacy Requirements for MISO Load Serving Entities (LSEs). [1] This report provides the resulting PRMs for the upcoming year—Summer (7.9%), Fall (11.6%), Winter (18.9%), and Spring (23.4%), which reflect a more nuanced understanding of evolving seasonal risks, particularly the growing impact of winter conditions. These updates enhance the transparency and reliability of the PRA process and reflect MISO's ongoing efforts to support system-wide resource adequacy.

Methodology Enhancements Following Software Issue

In 2025, MISO identified an issue with a third-party software tool used in its LOLE calculations, which led to a deviation from the LOLE definition in the Tariff. While the error had implications for prior market outcomes, MISO responded promptly and thoroughly to address the root cause and reinforce the integrity of its LOLE process. To prevent recurrence and improve future assessments, MISO implemented a series of corrective and preventive measures. These included a detailed analysis of raw software outputs to verify results, as well as comprehensive quality assurance and quality control (QA/QC) of model inputs and outputs. Year-over-year validation was also introduced to ensure consistency and accuracy in representing system risk. These actions reflect MISO's commitment to continuous improvement and to providing stakeholders with reliable, data-driven resource adequacy assessments.

Key Insights from the 2026-2027 LOLE Study

The seasonal PRMs for PY 2026-2027 show modest year-over-year changes across all seasons as reflected in the table below: Summer (7.9%), Fall (11.6%), Winter (18.9%), and Spring (23.4%) (Table ES-1). This year's LOLE analysis highlights a continued shift in system risk—from traditional summer peak periods to colder months and off-peak times—reflecting the evolving nature of load patterns and the resource fleet. Key factors contributed to these shifts and underscore the importance of seasonal planning and continued refinement of reliability assessments:

- **Load Growth:** Member-submitted forecasts indicate a 2–3 GW increase in system peak demand across all seasons.
- **Modeling Enhancements:** Updates to the dispatch modeling of storage and demand response resources led to a ~1.5% reduction in capacity requirements, particularly in Summer.
- **Cold Weather Risk:** Refined cold weather outage profiles using the most recent five years of historical data and aligned with Direct Loss of Load (DLOL) resource classes.

[1] All PRM and LRR references in this document refer to Planning Reserve Margin and Local Reliability Requirements in terms of Unforced Capacity, unless stated otherwise explicitly. (i.e. PRM ICAP)

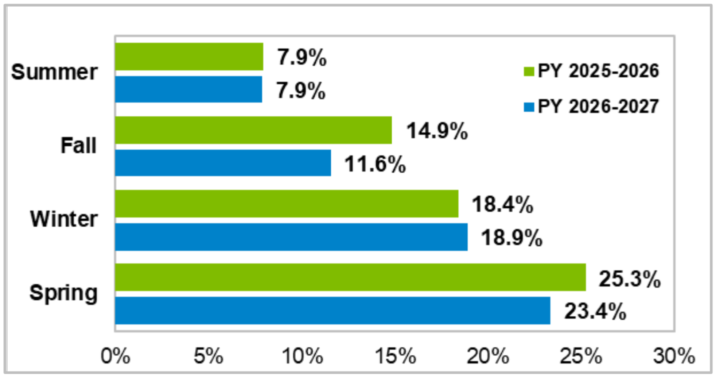


Table ES-1: Planning Reserve Margin Comparison with Prior Planning Year

The Expected Unserved Energy (EUE) heatmap (Figure ES-1) illustrates MISO's system risk for PY 2026-2027 compared to PY 2025-2026. Any EUE that materialized for each month and hour after the annual risk calibrations were conducted, but before Fall and Spring were calibrated to LOLE seasonal criteria. While a small amount of risk was observed in the morning hours of January in the PY 2025-2026 model, risk in the PY 2026-2027 model was observed in all three Winter months and February evening hours, as well as a small amount of risk in March morning hours.

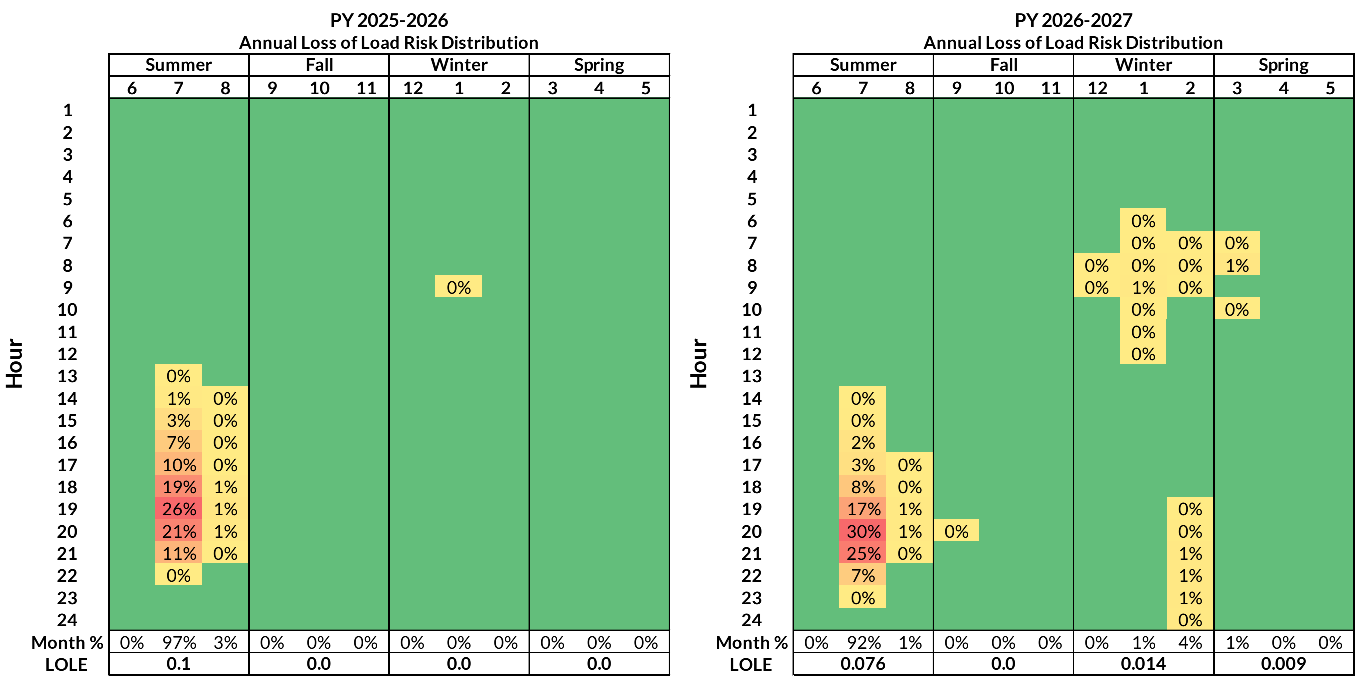


Figure ES-1: Annual Loss of Load Risk Distribution Year-Over-Year Comparison

In addition to the temporal distribution of risk, the supplemental risk metrics in Table ES-2 help explain changes in system risk[2]. Like LOLE, loss of load hours (LOLH) is measured across all hours where system risk occurs, and the values remained relatively stable year over year. EUE is the magnitude of the shortfall when demand exceeds generation and is also measured during all hours of simulation. EUE values increased in all four seasons, which indicates that the risk-calibrated model is of larger magnitude for PY 2026-2027 compared to PY 2025-2026.

[2] Additional information about resource adequacy risk metrics can be found in MISO's [Resource Adequacy Metrics and Criteria Roadmap report]

After accounting for the demand response and storage resource modeling enhancements, the adjustment needed to calibrate the system to 1 day in 10 years annual LOLE criterion was smaller in PY 2026-2027 for all four seasons, meaning that the system had less excess capacity than the prior year.[3]

MISO LOLE Risk Metrics	Summer		Fall		Winter		Spring	
	PY 25-26	PY 26-27	PY 25-26	PY 26-27	PY 25-26	PY 26-27	PY 25-26	PY 26-27
Loss of Load Expectation (LOLE) [days/year]	0.100	0.076	0.010	0.010	0.010	0.014	0.010	0.010
Loss of Load Hours (LOLH) [hours/season]	0.252	0.235	0.015	0.014	0.021	0.030	0.013	0.011
Expected Unserved Energy (EUE) [megawatt-hours/season]	626.161	983.783	18.936	22.066	24.378	53.921	12.807	17.793
Normalized EUE [parts per million/season]	0.926	1.402	0.028	0.031	0.036	0.077	0.019	0.025
MW Adjustment to LOLE Criteria	-960	-1,440	-9,590	-7,550	-6,110	-1,440	-10,000	-1,820

Table ES-2: Additional Risk Metrics

Table ES-3 summarizes how year-over-year changes in the generation fleet, load shapes, and the modeling assumptions of storage, demand response, cold weather outages, and non-firm imports impact system risk and its distribution across the studied prompt Planning Year.

Model Input / Assumption	System Risk	Notes
Generation Fleet Changes	↓	Some older, less efficient thermal units were replaced with new units with better performance which reduced risk and the PRM. Solar capacity increased as well, which shifted risk to periods with lower solar generation, like into the Winter season and later in the day during Summer.
Load	↑	Peak load forecasts increased significantly, and load shapes were updated with the latest five years of historical data, which resulted in increased system risk.
Cold-Weather Outages	↑	Updating the cold weather outages with the most recent 5 years of historical GADS and temperature data resulted in higher amounts of modeled outages at extremely cold temperatures, especially for southern MISO zones. System risk increased in Winter and Spring as a result.
Planned Maintenance	↓	With some new thermal units replacing older and less efficient units, planned maintenance fell overall, which reduced the system risk. Additionally, with the increase in solar resource capacity, the planned maintenance shape shifted to account for the change in net peak load observed. The Fall season saw a reduction in planned maintenance compared to that in the prior Planning Year.
Non-firm Support	↑	Non-firm support decreased when compared to last year, which increased system risk and increased the UCAP MW required to achieve the target LOLE.
Storage/Demand Response Dispatch	↓	Updates to the modeling software aligned Demand Response (DR) dispatch with expected unserved energy, which allowed DR resources to better offset system risk. The update was most significant for the Summer season.

Table ES-3: Year-Over-Year System Risk Drivers from Model Inputs and Assumptions

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). These variables are covered in Section 4 of this report.

[3] The annual adjustment that would have occurred in the PY 2025-2026 LOLE model with the software updates that improve the accounting for demand response and storage modeling is -2,740: PY 2025-2026 Indicative DLOL Results

1 MISO System Planning Reserve Margin

1.1 Planning Year 2026-2027 MISO Planning Reserve Margin Results

For Planning Year 2026-2027, the ratio of MISO Unforced Capacity to forecasted MISO system peak demand yielded a Planning Reserve Margin of 7.9 percent for the Summer season and 18.9 percent for the Winter season. The MISO system PRM calculation is presented in Table 1-1.

MISO Planning Reserve Margin (PRM)	PY 2026-2027 Summer	PY 2026-2027 Fall	PY 2026-2027 Winter	PY 2026-2027 Spring	Formula Key
MISO System Peak Demand (MW)	125,531	111,042	106,248	101,854	**[A]**
Unforced Capacity (MW)	135,743	130,395	126,514	126,438	**[B]**
Thermal	105,905	105,649	108,831	104,295	[B.1]
Run of River/Biomass	1,130	984	1,048	1,135	[B.2]
Wind	5,207	6,610	8,863	5,542	[B.3]
Solar	5,584	2,685	2,628	4,213	[B.4]
Battery Storage	706	706	702	706	[B.5]
Demand Response	8,162	6,649	6,798	6,708	[B.6]
BTMG	4,334	3,831	3,301	4,236	[B.7]
New Thermal	3,082	3,041	3,434	4,203	[B.8]
New Wind and Solar	1,633	1,069	2,228	3,250	[B.9]
Cold Weather Outage Impacts	0	(830)	(11,320)	(7,850)	[B.10]
Firm External Support UCAP (MW)	1,088	1,034	1,282	1,036	**[C]**
Adjustment to UCAP (MW)	(1,440)	(7,550)	(1,440)	(1,820)	**[D]**
UCAP PRM Requirement (PRMR) (MW)	135,391	123,878	126,356	125,654	**[E]** = [B]+[C]+[D]
MISO PRM	**7.9%**	**11.6%**	**18.9%**	**23.4%**	**[F]** = [E]-[A]/[A]

Table 1-1: Planning Year 2026-2027 MISO System Planning Reserve Margin

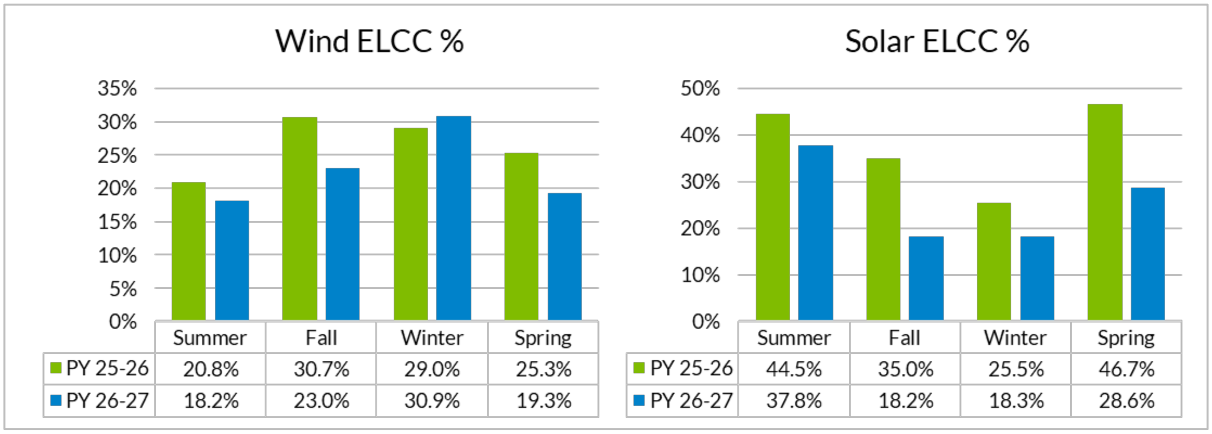
The actual effective Initial Planning Reserve Margin Requirement (PRMR) for each season of the 2026-2027 Planning Resource Auction will be determined after the updated peak demand forecasts have been submitted by the Load Serving Entities and reviewed by MISO following the November 1, 2025 submission deadline.

1.1.1 Effective Load Carrying Capability (ELCC) Results

In addition to the annual analysis of the prompt Planning Year's PRM, MISO performs seasonal Effective Load Carrying Capability (ELCC) analyses for front-of-meter wind and solar resources to quantify their average capacity contribution to determine season-wide capacity values for use in the seasonal PRM and LRR calculations. Wind and solar generation is represented in the model with 30-year hourly generation potential profiles.

Seasonal wind ELCC determines the allocable Seasonal Accredited Capacity (SAC) for in-service CPNode wind resources for the prompt Planning Year's PRA. Solar ELCC is not used for accreditation and is only used for calculating Resource Adequacy Requirements (RAR).

Figure 1-1 details the resulting LOLE study ELCC as percentages of Installed Capacity over the last two Planning Years.



Wind ELCC %	Summer	Fall	Winter	Spring
PY 25-26	20.8%	30.7%	29.0%	25.3%
PY 26-27	18.2%	23.0%	30.9%	19.3%

Solar ELCC %	Summer	Fall	Winter	Spring
PY 25-26	44.5%	35.0%	25.5%	46.7%
PY 26-27	37.8%	18.2%	18.3%	28.6%

Figure 1-1: Planning Year 2026-2027 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, resulting in shifts in the timing of risk hours observed from each year's model. Additionally, due to the Summer season having a higher share of the annual LOLE at the system-wide level, there is a greater volume of observed loss of load hours 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 and typically results in more stable ELCC values for this season.

Seasonal drivers of change from PY 2025-2026 to PY 2026-2027 are detailed below:

- **Summer**: In PY 2026-2027, there were long events observed in July and August. Additional solar capacity shifted risk hours slightly later in the day to the point where both wind and solar resources had a lower capability of producing energy. This resulted in lower wind and solar ELCC.
- **Fall**: In PY 2026-2027, system risk was distributed across more weather years and months within the season when compared to PY 2025-2026. This translated into a wider range of generating conditions for both wind and for solar resources and resulted in a reduction in ELCC.
- **Winter**: In PY 2026-2027, risk in Winter shifted from morning and mid-day to, primarily, evening hours. This resulted in a reduction in solar ELCC and a slight increase in wind ELCC.
- **Spring**: In PY 2026-2027, Spring risk continued to almost exclusively concentrate in March. Risk was most concentrated into fewer hours, where wind and solar performance was more limited. As a result, MISO saw a decrease in both wind and solar ELCC.

More details regarding wind and solar accreditation will be provided in the PY 2026-2027 Wind and Solar Capacity Credit Report.

2 Local Resource Zone Analysis – LRR Results

2.1 Planning Year 2026-2027 Local Resource Zone Analysis

When determining the Local Reliability Requirements (LRR) per zone for the upcoming PY, each of the 10 LRZs are modeled as if they were an island, without the benefit of support from other LRZs and neighboring external systems. This method is used to determine the quantity of Unforced Capacity that is needed internal to each LRZ to achieve seasonal LOLE criteria for each season. For the PRA, LRR is reduced by each LRZ's seasonal Capacity Import Limit (CIL) to calculate the zonal Local Clearing Requirement (LCR) of each season.

MISO is divided into the following 10 Local Resource Zones (LRZs), as shown in Figure 2-1. Those LRZs are composed by the Local Balancing Authorities listed in Table 2-1.

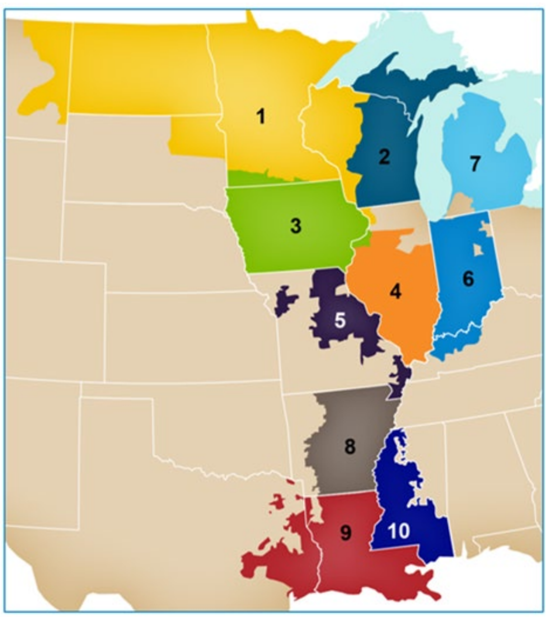


Figure 2-1: Map of MISO Local Resource Zones

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, LAGT, LEPA
10	EMBA, SME

Table 2-1: Local Balancing Authority to Local Resource Zone Designations

To reach the target LOLE per season, the solution methodology remains the same as what is used for the system-wide Planning Reserve Margin analysis[4]. First, the LOLE analysis across the entire Planning Year will be conducted by either adding or removing capacity until the LOLE reaches 0.1 day per year for the LRZ. If the LOLE for the Planning Year is less than 0.1 day per year, a perfect negative unit with zero forced outage rate will be added until the LOLE reaches 0.1 day per year. If the LOLE for the Planning Year is greater than 0.1 day per year, proxy units based on a unit of typical size and forced outage rate will be added to the model until the LOLE reaches 0.1 day per year. If the LOLE for a season is equal to or greater than 0.01 day per year for the LRZ, the LRR for that season will be calculated based on this LOLE analysis. If the LOLE for any season is less than 0.01 day per year for the LRZ, an additional LOLE analysis will be performed to determine the LRR for that season by adding a perfect negative unit with zero forced outage rate to that season until the LOLE in that season reaches 0.01 day per year for the LRZ.

[4] Module E-1 defines the PRM methodology in Section 68A.2.1 and LRR methodology in Section 65A.5.

The annual distribution of LOLE across the four seasons at the target metric of 1 day in 10 years, or 0.1 day per year, determined through the PY 2026-2027 LOLE study, is shown in Table 2-2. The MISO-wide seasonal LOLE distribution results from the PRM analyses, and the zonal distributions result from the LRR analyses. The blue LOLE values represent seasons that met the minimum seasonal LOLE criteria of 0.01 day per year during the annual analysis for that zone/region. The black values denote the seasons that had not achieved the minimum seasonal LOLE criteria from the annual simulation and required additional negative adjustment in the model to reach 0.01 day per year of LOLE.

Region	Summer	Fall	Winter	Spring
MISO-wide	0.076	0.01	0.014	0.01
LRZ 1	0.093	0.01	0.01	0.01
LRZ 2	0.083	0.01	0.018	0.01
LRZ 3	0.097	0.01	0.01	0.01
LRZ 4	0.01	0.01	0.094	0.01
LRZ 5	0.01	0.01	0.079	0.013
LRZ 6	0.087	0.011	0.01	0.01
LRZ 7	0.090	0.01	0.01	0.01
LRZ 8	0.01	0.01	0.100	0.01
LRZ 9	0.01	0.01	0.079	0.01
LRZ 10	0.01	0.01	0.083	0.01

Table 2-2: Planning Year 2026-2027 Seasonal LOLE Distribution

The results of the per-unit LRR of LRZ seasonal peak demand for PY 2026-2027 on a seasonal basis are found in Tables 2-3 through 2-6. The values in these tables show the components of the seasonal UCAP LRR values within each LRZ, including Coordinating Owner External Resources and Border External Resources. The adjustments to UCAP values are the adjustments to capacity needed to bring each LRZ to the seasonal criteria in the model. 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 calculated as the ratio of each LRZ's forecasted seasonal peak demand.

This ration will be multiplied by the updated LRZ seasonal peak demand forecasts submitted for the 2026-2027 PRA to determine 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[5].

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

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 2026-2027 Local Reliability Requirements - Summer 2026											
Installed Capacity (MW)	20,304	14,275	11,539	9,157	7,858	18,261	22,302	11,965	22,735	6,232	[A]
Unforced Capacity (MW)	19,351	13,651	10,873	8,738	7,289	16,761	20,681	11,337	21,278	5,784	[B]
Adjustment to UCAP (MW)	1,516	494	2,594	2,759	3,319	5,125	2,472	-5	3,879	1,417	[C]
Local Reliability Requirement (LRR) UCAP (MW)	20,867	14,145	13,467	11,496	10,608	21,886	23,154	11,332	25,157	7,201	[D]=[B]+[C]
Peak Demand (MW)	18,927	12,874	10,567	8,795	8,225	17,728	21,012	8,217	21,801	5,185	[E]
LRR UCAP per-unit of LRZ Peak Demand	**110.3%**	**109.9%**	**127.4%**	**130.7%**	**129.0%**	**123.5%**	**110.2%**	**137.9%**	**115.4%**	**138.9%**	[F]=[D]/[E]

Table 2-3: Planning Year 2026-2027 LRZ Local Reliability Requirements for Summer 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 2026-2027 Local Reliability Requirements - Fall 2026											
Installed Capacity (MW)	19,437	14,198	12,066	8,676	7,803	17,123	21,974	11,591	22,892	6,302	[A]
Unforced Capacity (MW)	18,412	13,189	11,328	8,123	7,189	15,640	20,061	10,652	20,319	5,482	[B]
Adjustment to UCAP (MW)	1,023	-480	2,106	2,150	2,585	4,971	2,398	878	3,904	1,050	[C]
Local Reliability Requirement (LRR) UCAP (MW)	19,435	12,709	13,434	10,273	9,773	20,611	22,459	11,530	24,224	6,532	[D]=[B]+[C]
Peak Demand (MW)	16,137	11,069	9,420	8,156	7,139	15,955	18,715	7,472	20,487	4,793	[E]
LRR UCAP per-unit of LRZ Peak Demand	**120.4%**	**114.8%**	**142.6%**	**126.0%**	**136.9%**	**129.2%**	**120.0%**	**154.3%**	**118.2%**	**136.3%**	[F]=[D]/[E]

Table 2-4: Planning Year 2026-2027 LRZ Local Reliability Requirements for Fall 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 2026-2027 Local Reliability Requirements - Winter 2026-2027											
Installed Capacity (MW)	20,121	14,665	13,692	9,300	8,043	18,840	22,624	12,337	24,916	6,630	[A]
Unforced Capacity (MW)	18,310	11,935	12,390	6,328	5,592	15,250	20,664	9,397	21,067	5,581	[B]
Adjustment to UCAP (MW)	1,029	487	2,130	2,817	3,371	4,101	-540	2,243	3,993	1,444	[C]
Local Reliability Requirement (LRR) UCAP (MW)	19,339	12,422	14,520	9,145	8,963	19,351	20,124	11,640	25,060	7,025	[D]=[B]+[C]
Peak Demand (MW)	15,972	9,877	8,984	7,538	7,303	15,541	14,367	7,641	20,045	4,675	[E]
LRR UCAP per-unit of LRZ Peak Demand	**121.1%**	**125.8%**	**161.6%**	**121.3%**	**122.7%**	**124.5%**	**140.1%**	**152.3%**	**125.0%**	**150.3%**	[F]=[D]/[E]

Table 2-5: Planning Year 2026-2027 LRZ Local Reliability Requirements for Winter 2026-2027

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 2026-2027 Local Reliability Requirements - Spring 2027											
Installed Capacity (MW)	18,920	14,564	12,126	9,256	7,343	18,205	21,937	12,035	24,470	6,452	[A]
Unforced Capacity (MW)	17,733	12,855	11,217	7,471	6,020	15,815	19,480	10,027	20,032	5,787	[B]
Adjustment to UCAP (MW)	947	-618	1,432	2,153	3,428	3,043	1,291	1,356	3,872	1,468	[C]
Local Reliability Requirement (LRR) UCAP (MW)	18,680	12,237	12,649	9,624	9,448	18,858	20,771	11,383	23,904	7,255	[D]=[B]+[C]
Peak Demand (MW)	16,051	10,428	8,640	6,832	6,888	14,721	16,531	6,826	19,879	4,550	[E]
LRR UCAP per-unit of LRZ Peak Demand	**116.4%**	**117.4%**	**146.4%**	**140.9%**	**137.2%**	**128.1%**	**125.7%**	**166.8%**	**120.2%**	**159.5%**	[F]=[D]/[E]

Table 2-6: Planning Year 2026-2027 LRZ Local Reliability Requirements for Spring 2027

3 Loss of Load Expectation Analysis

MISO uses a program maintained by PowerGEM called Strategic Energy & Risk Valuation Model (SERVM) to calculate LOLE for the applicable PY. 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. For each hour in the simulation SERVM takes into account generation, load, load modifying resources, generator forced outages, generator planned maintenance outages, weather and economic uncertainty, and external support from neighboring regions.

This section provides a description of the data, sources, and updates in this year's model.

3.1 Capacity Resource Qualification and Model Validation

3.1.1 Resource Inclusion

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 includes resources for each season if that resource is included in a Fixed Resource Adequacy Plan (FRAP) or offered into the prior year's PRA, with an exception for external resources.

External resources are included in the LOLE model for each season if such 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 Quality Assurance and Quality Control

Last year, MISO discovered a third-party software error that caused its LOLE calculations to deviate from the LOLE definition in its Tariff[6]. This error persisted over multiple periods and had material impacts on market outcomes. To prevent a recurrence of the LOLE miscalculation issue, MISO has taken several corrective and preventive actions. MISO filed a Tariff revision with FERC to update its definition of LOLE and FERC approved it on October 24, 2025. The new definition of LOLE is used in this study and matches the calculations provided by the software. LOLE represents an estimate of the average number of days with supply interruption to end use customers, whether for a single hour or multiple hours in a day.

MISO is continuously enhancing its LOLE study methodology to better reflect actual resource availability and is reviewing its software validation and quality assurance processes to strengthen internal controls and prevent similar issues in the future. To better understand the checks that MISO conducts each year, these are broken out into the two categories of inputs and outputs and are detailed below.

Input Data Validation

- Year-over-year checks were conducted to ensure that weather-based inputs and daily profiles were reasonable.
- The load development process was reviewed and validated after every step of the six-step process and then again prior to the import of the load shapes into the LOLE model.
- Planned maintenance profiles were exported from the model prior to any simulations for the MISO system-wide and LRZ runs and compared with the prior year. Inputs for planned maintenance rates and the corresponding planned maintenance schedule inputs generated and optimized by SERVM were analyzed to

[6] LOLE continuing error presentation at the August 2025 RASC: https://cdn.misoenergy.org/20250820%20RASC%20Item%2005%20LOLE%20Continuing%20Error714224.pdf

ensure that either set of inputs resulted in consistent planned maintenance schedules for each year and region being studied.
- Supporting resource capability assumptions including outage rates, seasonal availability, ICAP, UCAP, and unit categories were verified by several MISO staff members.
- Prior to importing any new data into the SERVM model, MISO staff reviewed and discussed these inputs and made any necessary changes.

In addition to the checks mentioned above, MISO publishes much of this supporting data on its ShareFile for stakeholders to review and analyze. MISO also discusses model input and assumptions during the model build updates at the LOLEWG meetings.

Output Data Validation

- Calibration checks were conducted in partnership with PowerGEM each time a new major version of SERVM was released to confirm that unintended deviations in simulation results did not occur.
- Resource type dispatch order and behavior during EUE events were reviewed and validated.
- Multiple risk metrics were analyzed from model results to better understand changes in LOLE, LOLH, EUE hours, EUE magnitude, and EUE duration.
- Examinations were conducted on high-risk days that drive seasonal risk. This was done by comparing the load and generation observed on these days along with their corresponding hours of risk.

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 2020 to December 2024) 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 weighted class average forced outage rates as well as the current Planning Year's MISO system-wide forced outage rates are provided in Tables 3-1, 3-2, 3-3, and 3-4. These tables show the year-over-year trends for a resource class's forced outages, while Table 3-5, displays the year-over-year trends on an annual basis for planned maintenance per resource class over the last five Planning Years. Data presented in these tables is only able to be made public when a resource class has more than 30 units.

Pooled EFORd GADS Years	2020-2024 (%)	2019-2023 (%)	2018-2022 (%)	2017-2021 (%)	2016-2020 (%)
LOLE Study Planning Year	**PY 2026-2027** Summer	**PY 2025-2026** Summer	**PY 2024-2025** Summer	**PY 2023-2024** Summer	**PY 2022-2023** Annualized
Combined Cycle	4.59	5.26	5.92	5.54	5.85
Combustion Turbine (0-50 MW)	16.08	10.80	7.65	7.37	15.25
Combustion Turbine (50+ MW)	5.85	4.72	4.88	4.07	4.36
Diesel Engines	30.65	17.52	17.14	12.79	7.25
Steam – Coal (0-400 MW)	9.53	11.76	8.22	7.03	9.91
Steam - Coal (400-1,000 MW)	9.86	8.84	8.62	8.06	9.00
Steam - Gas	11.74	11.32	14.04	12.48	11.84
MISO Weighted System-wide	7.45	7.76	8.24	8.23	9.04

Table 3-1: Historical Class Average Forced Outage Rates for Summer Season

Pooled EFORd GADS Years	2020-2024 (%)	2019-2023 (%)	2018-2022 (%)	2017-2021 (%)	2016-2020 (%)
Fall Season / Annual	**Fall 2026**	**Fall 2025**	**Fall 2024**	**Fall 2023**	**PY 2022-2023 Annualized**
Combined Cycle	6.55	6.95	7.43	8.32	5.85
Combustion Turbine (0-50 MW)	28.55	13.42	18.86	21.22	15.25
Combustion Turbine (50+ MW)	8.67	7.96	7.23	6.60	4.36
Diesel Engines	33.17	31.84	14.26	9.32	7.25
Steam – Coal (0-400 MW)	11.08	15.27	10.66	8.96	9.91
Steam - Coal (400-1,000 MW)	9.93	9.20	8.73	8.40	9.00
Steam - Gas	14.06	12.91	13.26	13.66	11.84
MISO Weighted System-wide	8.93	8.93	9.15	9.48	9.04

Table 3-2: Historical Class Average Forced Outage Rates for Fall Season

Pooled EFORd GADS Years	2020-2024 (%)	2019-2023 (%)	2018-2022 (%)	2017-2021 (%)	2016-2020 (%)
Winter Season / Annual	**Winter 2026-2027**	**Winter 2025-2026**	**Winter 2024-2025**	**Winter 2023-2024**	**PY 2022-2023 Annualized**
Combined Cycle	4.67	5.16	5.38	4.70	5.85
Combustion Turbine (0-50 MW)	47.18	33.67	49.76	55.87	15.25
Combustion Turbine (50+ MW)	7.33	12.50	10.53	9.68	4.36
Diesel Engines	28.59	24.53	24.94	14.84	7.25
Steam – Coal (0-400 MW)	10.60	12.68	9.13	7.76	9.91
Steam - Coal (400-1,000 MW)	10.49	9.83	9.63	8.49	9.00
Steam - Gas	13.71	9.83	11.11	8.28	11.84
MISO Weighted System-wide	10.85	10.48	11.23	12.47	9.04

Table 3-3: Historical Class Average Forced Outage Rates for Winter Season

Pooled EFORd GADS Years	2020-2024 (%)	2019-2023 (%)	2018-2022 (%)	2017-2021 (%)	2016-2020 (%)
Spring Season / Annual	**Spring 2027**	**Spring 2026**	**Spring 2025**	**Spring 2024**	**PY 2022-2023 Annualized**
Combined Cycle	5.84	5.93	6.55	6.19	5.85
Combustion Turbine (0-50 MW)	35.06	15.79	35.65	28.54	15.25
Combustion Turbine (50+ MW)	5.78	5.31	5.15	4.81	4.36
Diesel Engines	40.92	23.91	8.89	8.07	7.25
Steam – Coal (0-400 MW)	10.02	11.17	10.59	9.45	9.91
Steam - Coal (400-1,000 MW)	9.60	9.94	9.98	9.54	9.00
Steam - Gas	11.34	9.32	12.07	11.26	11.84
MISO Weighted System-wide	9.29	9.70	10.33	11.42	9.04

Table 3-4: Historical Class Average Forced Outage Rates for Spring Season

Pooled Planned Outage Rate (%) GADS Years	2020-2024 (%)	2019-2023 (%)	2018-2022 (%)	2017-2021 (%)	2016-2020 (%)
LOLE Study Planning Year	**PY 2026-2027** Summer	**PY 2025-2026** Summer	**PY 2024-2025** Summer	**PY 2023-2024** Summer	**PY 2022-2023** Annualized
Combined Cycle	10.74	9.80	10.56	11.89	10.47
Combustion Turbine	8.79	8.78	8.88	9.12	8.78
Diesels	3.29	4.34	4.94	5.02	7.34
Fossil Steam	12.89	12.07	12.57	12.82	12.78
Behind-the-Meter Generator	5.48	5.91	5.91	5.33	5.33

Table 3-5: Annual Historical Class Average Planned Maintenance 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, 2025) through MISO's Attachment Y process. Any resource with an approved retirement or suspension in Planning Year 2026-2027 was excluded from the prompt year 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 well as resources that had a valid Generator Replacement Request filed with MISO (as of June 1, 2025). 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 season, beginning the season 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 that have not been previously delayed 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 (COD Dashboard).

3.2.5 Intermittent Resources

Intermittent resources include solar, wind, biomass, 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 resources are exceptions to this and only submit historical output data for the top eight unique-day seasonal coincident demand peak hours 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 281 front-of-meter wind resources from 2013 to 2024, 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 (1995 – 2024), synthetic shapes were developed by PowerGEM for the 1995 – 2012 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 PowerGEM using historical solar irradiance data from the NREL National Solar Radiation Database (NSRDB) from 1998 – 2024.

3.2.6 Battery Storage

Battery storage resources are modeled based on their reservoir capacity and on their hourly equivalent discharge capabilities, performed annually and provided as part of their annual registration in the MECT tool. Battery storage resources are dispatch-limited resources and are the second-to-last set of resources dispatched by the SERVM tool in an effort to avoid loss of load or unserved energy. Battery storage dispatch is also limited in the model by the simulated operating margins which determines when these resources are able to recharge before being dispatched again.

3.2.7 Demand Response

Demand response programs and their capabilities came from their corresponding registrations in the MECT tool. These resources are modeled as dispatch-limited resources and are the last set of resources dispatched by the SERVM tool in an effort to avoid loss of load or unserved energy. Each demand response program was modeled individually with a seasonal 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 list the total ICAP value by resource type and LRZ in the PY 2026-2027 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 2026-2027 ICAP MW, Summer												
Resource Type	**LRZ1**	**LRZ2**	**LRZ3**	**LRZ4**	**LRZ5**	**LRZ6**	**LRZ7**	**LRZ8**	**LRZ9**	**LRZ10**	**Firm Externals**	**MISO**
Thermal	15,000	11,696	7,771	6,509	6,880	13,950	18,294	9,790	21,482	5,827	968	118,168
ROR/Biomass	269	197	18	0	126	190	160	32	228	0	166	1,386
Wind	7,244	898	13,029	2,323	406	1,480	3,593	180	0	185	0	29,338
Solar	768	2,145	674	3,336	1,069	4,082	1,861	2,498	1,687	651	0	18,772
Battery Storage	0	306	0	223	0	346	214	0	25	0	0	1,114
BTMG	1,491	365	619	316	95	351	1,157	17	14	81	0	4,506
Demand Response	1,939	736	512	425	280	1,611	1,120	1,148	348	45	0	8,162
Total	**26,712**	**16,345**	**22,622**	**13,133**	**8,856**	**22,011**	**26,400**	**13,665**	**23,784**	**6,788**	**1,133**	**181,447**

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

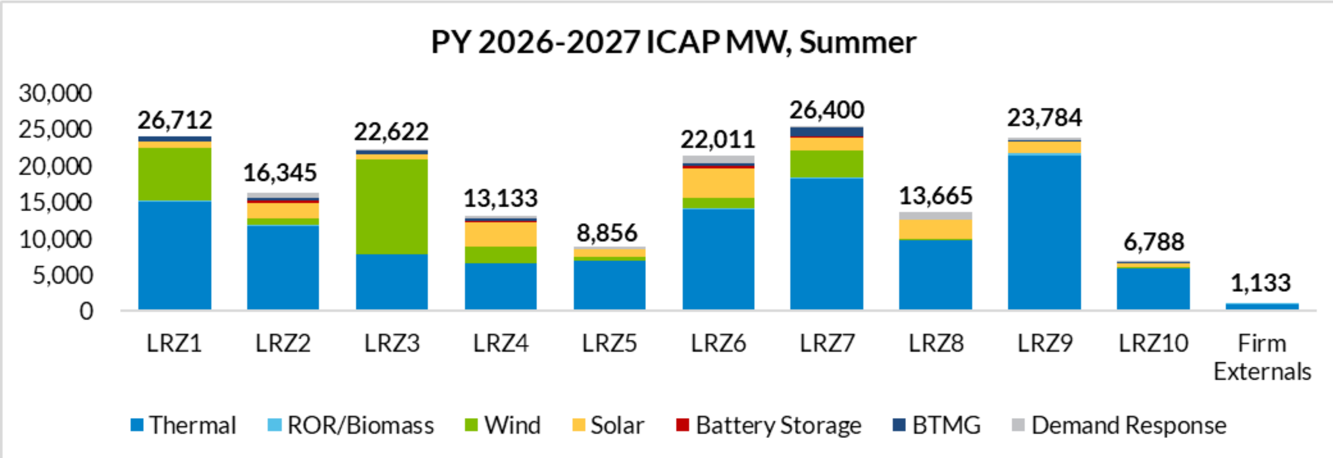


Figure 3-1: Summer Total Installed Capacity by Resource Type and Local Resource Zone

PY 2026-2027 ICAP MW, Fall												
Resource Type	**LRZ1**	**LRZ2**	**LRZ3**	**LRZ4**	**LRZ5**	**LRZ6**	**LRZ7**	**LRZ8**	**LRZ9**	**LRZ10**	**Firm Externals**	**MISO**
Thermal	14,665	12,019	7,864	6,619	7,078	13,923	18,668	9,981	21,998	6,027	960	119,803
ROR/Biomass	253	189	5	0	127	175	163	23	132	0	151	1,217
Wind	7,264	898	13,029	2,323	406	1,480	3,593	180	0	185	0	29,358
Solar	768	2,145	918	3,306	1,069	4,182	1,961	2,598	2,037	797	0	19,782
Battery Storage	0	326	0	223	0	346	214	0	25	0	0	1,134
BTMG	1,248	356	613	312	95	197	1,068	13	19	82	0	4,003
Demand Response	1,458	710	417	385	214	1,378	676	1,059	346	5	0	6,649
Total	**25,657**	**16,643**	**22,845**	**13,168**	**8,990**	**21,682**	**26,343**	**13,854**	**24,557**	**7,095**	**1,111**	**181,946**

Table 3-7: Fall Total Installed Capacity by Resource Type and Local Resource Zone

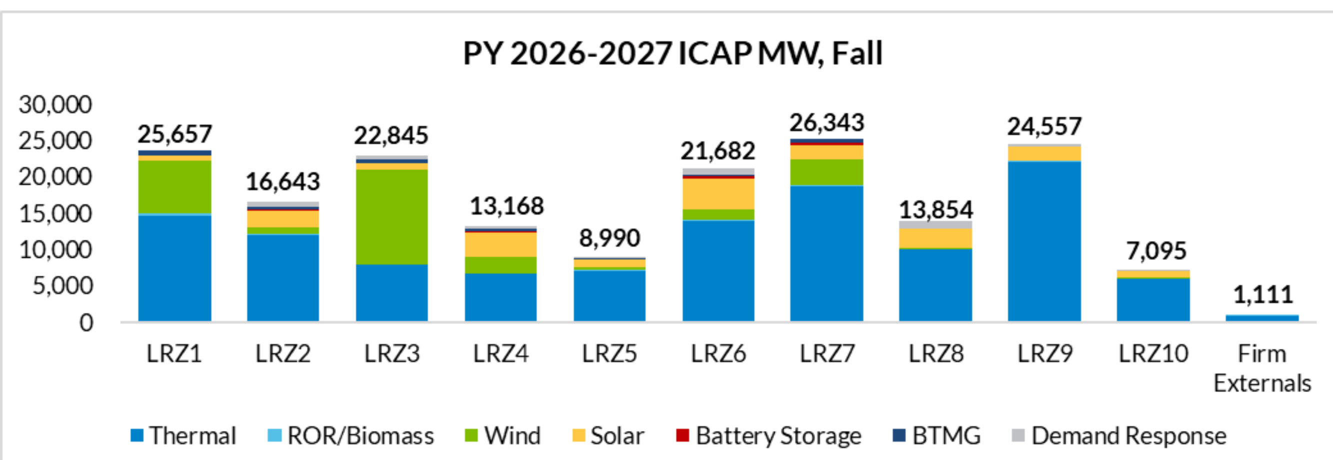


Figure 3-2: Fall Total Installed Capacity by Resource Type and Local Resource Zone

PY 2026-2027 ICAP MW, Winter											
Resource Type	**LRZ1**	**LRZ2**	**LRZ3**	**LRZ4**	**LRZ5**	**LRZ6**	**LRZ7**	**LRZ8**	**LRZ9**	**LRZ10**	**Firm Externals**	**MISO**
Thermal	14,876	12,383	8,146	7,028	7,379	15,187	18,951	10,534	23,724	6,285	1,228	125,719
ROR/Biomass	261	197	5	0	125	159	167	45	201	0	149	1,309
Wind	7,452	898	13,594	2,323	406	1,480	3,593	180	0	185	0	30,111
Solar	1,170	2,577	1,383	3,748	980	4,882	2,111	3,253	2,962	1,097	0	24,162
Battery Storage	0	326	75	219	0	346	414	0	95	0	0	1,475
BTMG	734	333	590	321	91	333	1,014	17	9	82	0	3,525
Demand Response	1,734	677	425	329	144	1,466	582	1,091	346	5	0	6,798
Total	**26,227**	**17,391**	**24,217**	**13,968**	**9,125**	**23,853**	**26,832**	**15,120**	**27,337**	**7,654**	**1,377**	**193,099**

Table 3-8: Winter Total Installed Capacity by Resource Type and Local Resource Zone

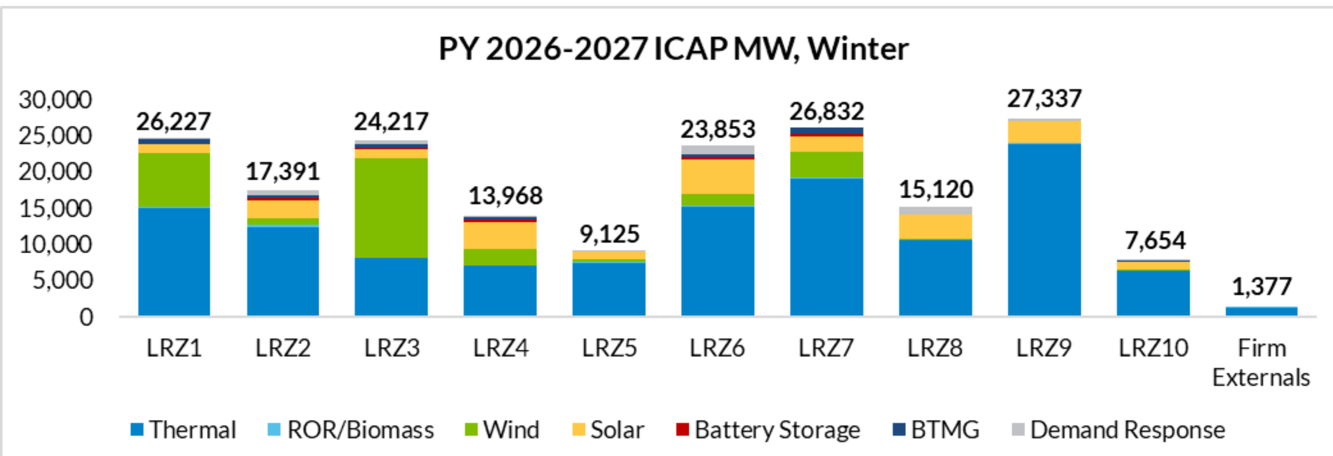


Figure 3-3: Winter Total Installed Capacity by Resource Type and Local Resource Zone

PY 2026-2027 ICAP MW, Spring											
Resource Type	**LRZ1**	**LRZ2**	**LRZ3**	**LRZ4**	**LRZ5**	**LRZ6**	**LRZ7**	**LRZ8**	**LRZ9**	**LRZ10**	**Firm Externals**	**MISO**
Thermal	13,980	11,992	7,991	6,783	6,541	14,087	18,242	9,691	22,914	5,973	953	119,147
ROR/Biomass	294	212	35	0	108	134	169	37	246	0	143	1,378
Wind	7,452	898	13,594	2,323	406	1,480	3,593	180	0	185	0	30,111
Solar	1,217	2,595	1,383	3,856	1,169	4,882	2,311	3,517	2,962	1,247	0	25,141
Battery Storage	0	326	75	223	0	464	414	136	95	0	0	1,733
BTMG	1,391	414	602	313	95	351	1,138	26	21	82	0	4,431
Demand Response	1,468	705	403	385	186	1,487	619	1,104	347	5	0	6,708
Total	**25,802**	**17,142**	**24,082**	**13,884**	**8,505**	**22,885**	**26,486**	**14,691**	**26,584**	**7,491**	**1,096**	**188,649**

Table 3-9: Spring Total Installed Capacity by Resource Type and Local Resource Zone

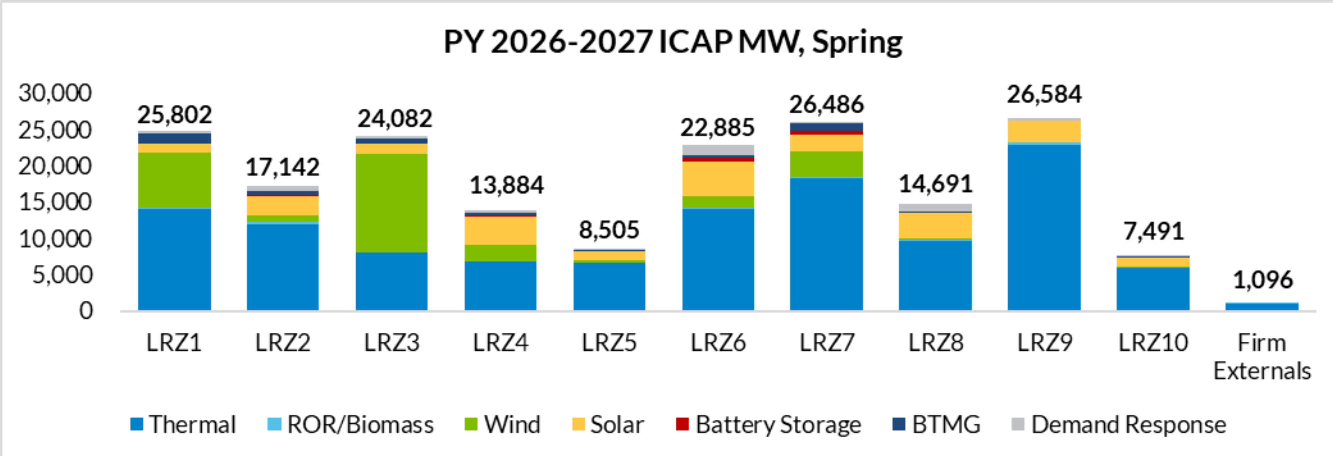


Figure 3-4: Spring Total Installed Capacity by Resource Type and Local Resource Zone

3.4 MISO Load Development Process

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 next LOLE study to align the load in the model with the anticipated load growth forecasted within each Local Resource Zone.

The LOLE analyses used a load training process paired with neural net software to establish a correlated relationship between the most recent five years of historical weather and load data. Correlated relationships are developed from the time of day, temperature, and load values observed in the five year data set. 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 and were then used to scale the load shapes so that the average monthly peak of the 30-year load shapes matched these forecasts. The results of this process are shown as the MISO System Peak Demand (Table 1-1) and zonal Peak Demand (Table 2-3 through 2-6).

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.

I. The load development process includes data collection of the most recent year of historical hourly load data for each LRZ and 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 2026-2027 LOLE study, five years of historical data (2020 - 2024) was used in the neural net training/prediction portion of the load development process.

   Historical load data used in this step of the load development process are gathered from MISO's Resource Assessment team and are 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 weather stations for each zone, as listed in Table 3-10.

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 3-10: Local Resource Zone Weather Stations

II. The next step of the process is to normalize the five historical 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 and provide an appropriate band of uncertainty.

III. After the most recent five historical years of load and weather data has been normalized, neural network software is utilized 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.

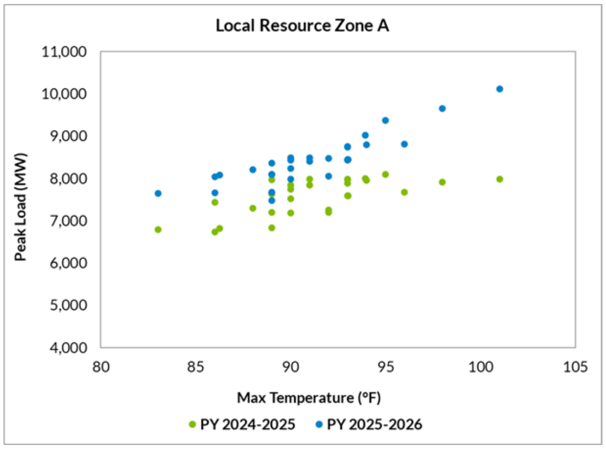
During the temperature and load training portion of this process, MISO evaluates each of the 10 LRZs by the following seasonal groupings: Summer, Winter, and off-season. Starting in the PY 2025-2026 LOLE study, the off-season grouping included both the Fall and Spring seasons. This was done to ensure 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 through 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 3-5 show how load responds to higher observed temperatures for months within the Fall and Spring seasons for the PY 2024-2025 and PY 2025-2026, this is because PY 2024-2025 was the last year with the older method and PY 2025-2026 displays the improvements found in this new methodology change.

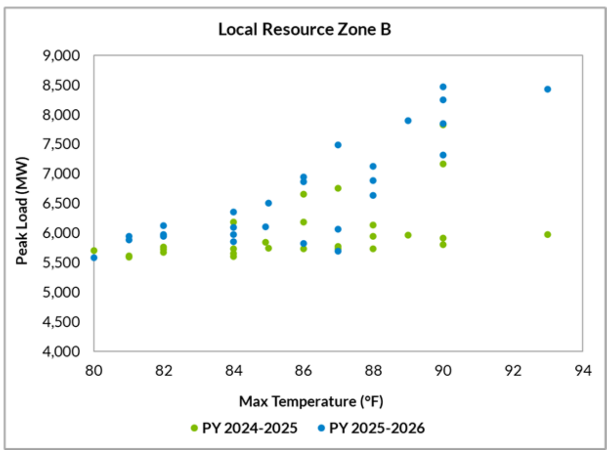
Comparable to off-season periods, the neural net software established functional relationships between historical temperature and load for the Summer and Winter seasons. However, unlike the off-season periods, the correlations between temperature and load for Summer and Winter seasons remained stable with the change in methodology that was implemented in the PY 2025-2026 LOLE study. When comparing the new method 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 3-6 show how load responds to higher observed temperatures for months within the Summer and Winter seasons.

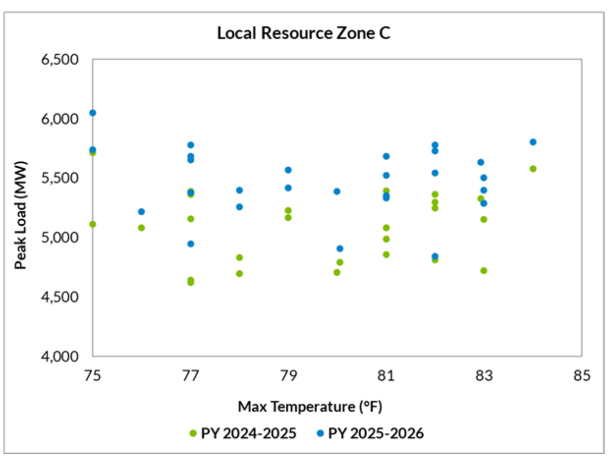
Fall Season
Temperature and Load Correlation
September



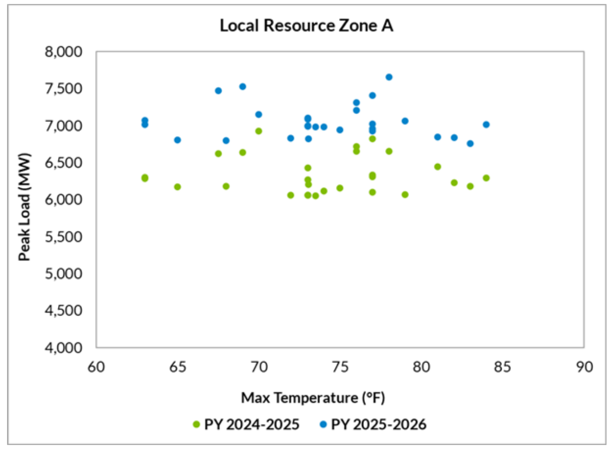
October



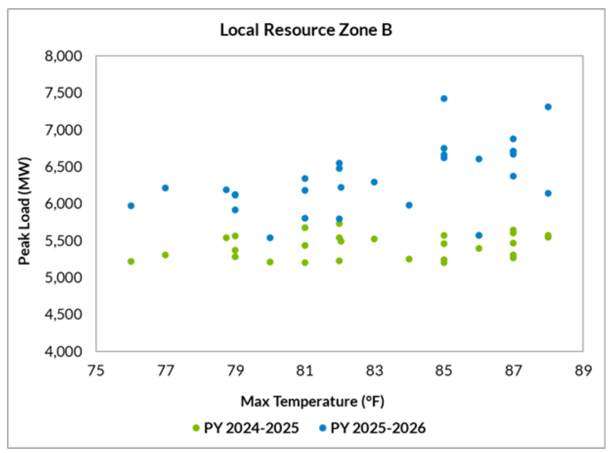
November



Spring Season
Temperature and Load Correlation
March



April



May

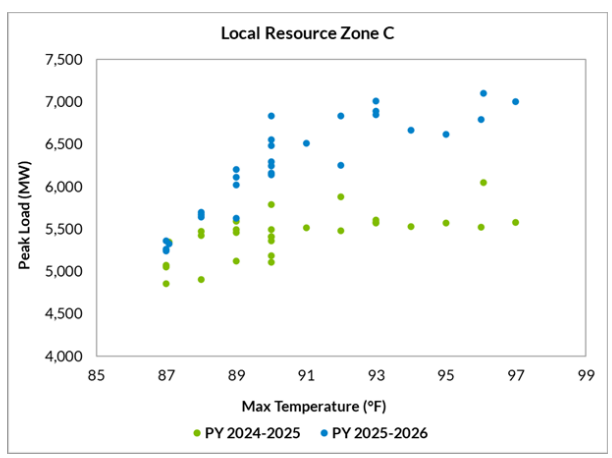
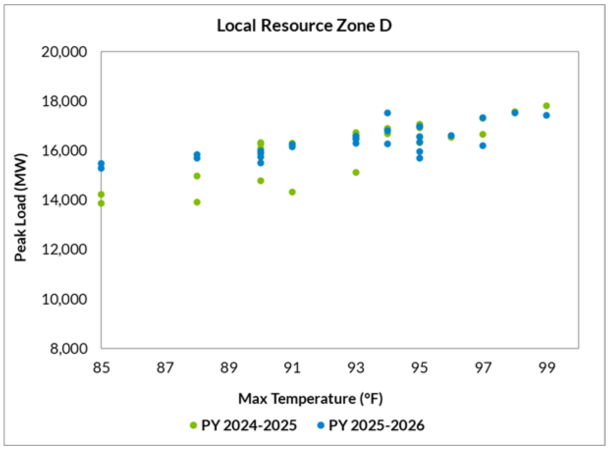
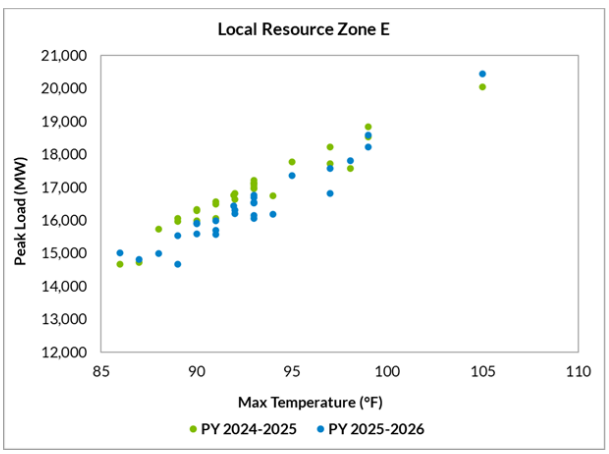


Figure 3-5: Temperature and Load Correlation for Fall and Spring Months

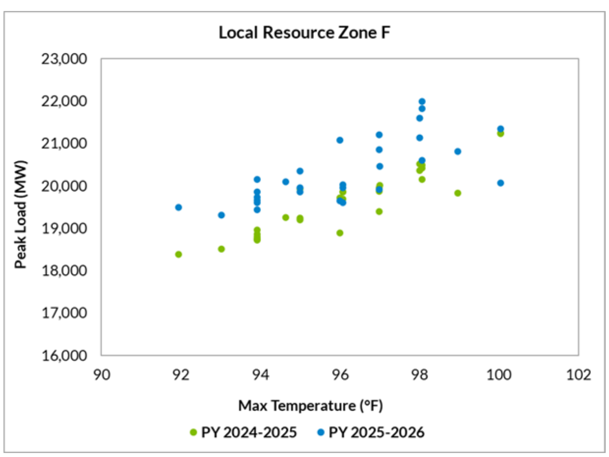
Summer Season
Temperature and Load Correlation
June



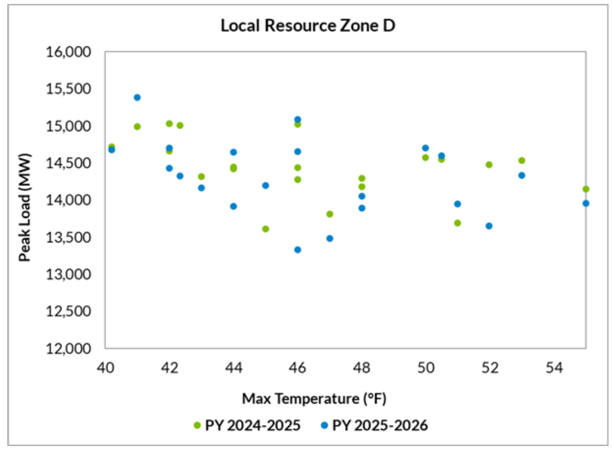
July



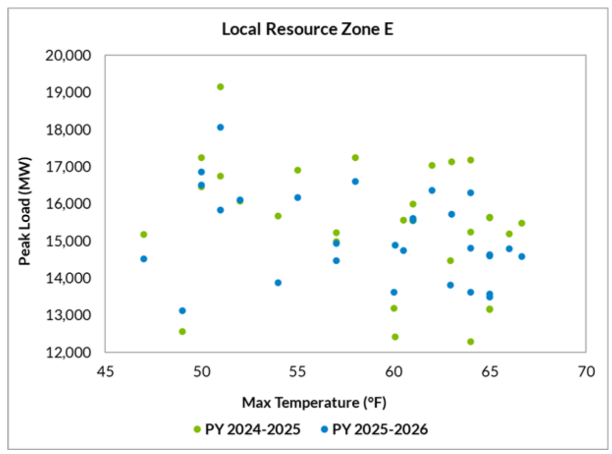
August



Winter Season
Temperature and Load Correlation
December



January



February

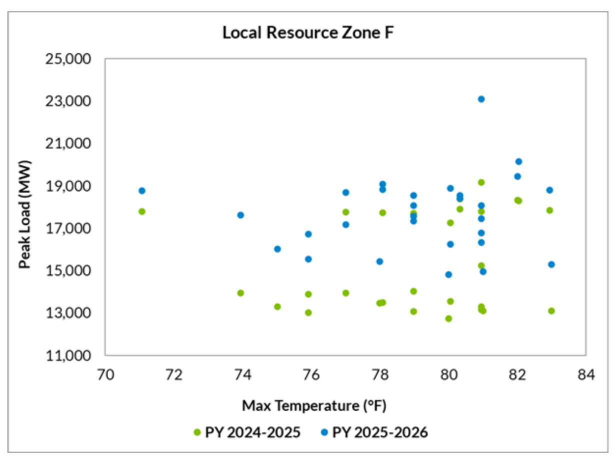


Figure 3-6: Temperature and Load Correlation for Summer and Winter Months

IV. After the neural net has finished, MISO validates 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 synthetic historical correlated load and weather data. During this step of the process, MISO creates 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. However, during model simulations for the PY 2026-2027 LOLE analysis, MISO saw additional risk materialization during cold morning hours of several weather years when the regression slopes were too steep, and this caused a prediction of unreasonably high load in some hours. Due to this, MISO staff softened the cold morning hours regression to allow for a more gradual increased load prediction during extreme cold temperatures. This change developed more realistic predictions during these affected periods and reduced the likelihood of EUE risk hour skewing toward these extreme events. Examples of this regression change can be seen in Figure 3-7.

Figure 3-7: Load Predictions Before and After Cold Morning Hour Regression Softening

V. Once adjustments to load during extreme temperatures are complete, 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 from the last five years, but they should be slightly higher to account for any load reductions that were included in the historical five-year 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.

VI. The final step of the load training process is to ensure that the average monthly peak load across all 30 years of the predicted load shape matches each LRZ's total monthly zonal Coincident Peak Demand forecast provided by the Load Serving Entities for each study year. 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 year 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, the standard deviation is calculated from the electric utility load growth forecast error, which equals 0.65%. This standard deviation is used to create a normal distribution representing the probabilities of the load forecast errors (LFE) as shown in Table 3-11.

LFE Levels	-2%	-1%	0%	1%	2%
Probability assigned to each LFE	1.05%	21.0%	55.8%	21.0%	1.05%

Table 3-11: Economic Uncertainty for Prompt Year

3.4.2 Final Load Details for the Prompt Planning Year

The following section provides additional detail on the outputs from the Planning Year 2026-2027 load development process that was used in the LOLE analysis for the upcoming Planning Year. The average seasonal peak demand by zone is shown in Table 3-12, the average monthly peak demand by zone is shown in Table 3-13, and the final load scaling factors that were developed in step six of the load development process per zone may be found in Table 3-14. The MISO system-wide and zonal peak demand timestamps for all 30 years modeled in the LOLE study are shown in Table 3-15 and the seasonal peak load variability for the prompt year MISO-wide system is shown in Figure 3-8. The peak demand timestamps are subject to the load development process and are not necessarily the actual historical peak days and times that occurred during these years.

Zone	Summer (MW)	Fall (MW)	Winter (MW)	Spring (MW)
MISO	125,531	111,042	106,248	101,854
LRZ 1 (DPC, GRE, MDU, MP, NSP, OTP, SMP)	18,927	16,137	15,972	16,051
LRZ 2 (ALTE, MGE, MIUP, UPPC, WEC, WPS)	12,874	11,069	9,877	10,428
LRZ 3 (ALTW, MEC, MPW)	10,567	9,420	8,984	8,640
LRZ 4 (AMIL, CWLP, GLH, SIPC)	8,795	8,156	7,538	6,832
LRZ 5 (AMMO, CWLD)	8,225	7,139	7,303	6,888
LRZ 6 (BREC, CIN, HE, HMPL, IPL, NIPS, SIGE)	17,728	15,955	15,541	14,721
LRZ 7 (CONS, DECO)	21,012	18,715	14,367	16,531
LRZ 8 (EAI)	8,217	7,472	7,641	6,826
LRZ 9 (CLEC, EES, LAFA, LAGT, LEPA)	21,801	20,487	20,045	19,879
LRZ 10 (EMBA, SME)	5,185	4,793	4,675	4,550

Table 3-12: Average Seasonal Peak Demand by Zone

Month	LRZ1	LRZ2	LRZ3	LRZ4	LRZ5	LRZ6	LRZ7	LRZ8	LRZ9	LRZ10	MISO
January	15,852	9,792	8,883	7,358	7,016	15,407	14,248	7,426	19,778	4,553	105,206
February	15,145	9,452	8,545	7,234	6,774	14,536	13,965	6,763	17,391	4,055	98,776
March	14,782	9,155	7,815	6,039	6,183	13,528	12,617	6,195	17,471	3,720	93,358
April	13,252	8,614	7,367	5,323	5,317	11,968	12,430	5,764	17,517	3,535	83,599
May	15,144	10,376	8,516	6,726	6,609	14,453	16,531	6,666	19,654	4,512	100,387
June	17,398	11,742	9,589	8,017	7,525	16,178	19,910	7,550	20,734	4,800	116,169
July	18,627	12,658	10,412	8,623	7,909	17,157	20,416	8,136	21,708	5,052	124,456
August	18,083	12,433	10,001	8,426	7,892	17,117	20,108	7,942	21,296	5,055	120,598
September	16,130	11,069	9,342	8,124	7,072	15,898	18,715	7,418	20,351	4,775	111,042
October	13,468	8,952	7,784	6,181	5,705	12,842	13,407	6,457	18,554	4,116	91,049
November	14,034	8,961	7,918	6,543	5,697	13,016	13,169	6,026	16,717	3,780	90,176
December	15,330	9,669	8,539	6,903	6,326	14,041	14,128	6,757	18,244	4,158	99,274

Table 3-13: Average Monthly Peak Demand by Zone (MW)

Month	LRZ1	LRZ2	LRZ3	LRZ4	LRZ5	LRZ6	LRZ7	LRZ8	LRZ9	LRZ10
January	108.8%	109.7%	115.8%	104.5%	104.3%	109.3%	110.4%	112.0%	106.7%	114.7%
February	105.6%	108.1%	114.1%	107.7%	107.7%	107.0%	108.6%	110.1%	101.4%	113.1%
March	108.6%	108.2%	110.1%	96.5%	109.7%	106.8%	100.4%	111.6%	109.0%	117.3%
April	104.3%	105.7%	108.3%	89.4%	102.5%	106.5%	102.6%	113.2%	110.1%	116.1%
May	109.1%	114.8%	109.9%	91.9%	109.0%	109.2%	109.8%	108.7%	103.9%	117.7%
June	107.2%	105.6%	107.8%	94.3%	104.9%	102.4%	105.0%	108.1%	102.6%	112.1%
July	112.5%	110.8%	112.4%	100.1%	103.9%	106.3%	107.1%	111.5%	106.2%	113.2%
August	113.9%	111.0%	110.4%	99.2%	104.4%	106.8%	106.3%	107.5%	103.7%	112.8%
September	106.7%	104.3%	109.8%	99.9%	104.4%	104.2%	108.2%	107.0%	102.5%	112.1%
October	107.5%	106.9%	111.4%	96.4%	109.7%	110.2%	107.6%	114.5%	105.6%	118.4%
November	104.0%	107.2%	111.3%	110.1%	108.0%	107.7%	108.7%	112.2%	110.2%	122.1%
December	107.3%	110.1%	114.1%	103.0%	101.5%	104.1%	110.4%	107.7%	104.7%	114.8%

Table 3-14: Final Load Scaling Factors by Zone

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
1995	7/13/95 17:00	7/13/95 18:00	7/13/95 16:00	7/13/95 17:00	7/13/95 16:00	8/18/95 17:00	7/14/95 18:00	7/14/95 16:00	7/28/95 18:00	7/28/95 18:00	7/28/95 16:00
1996	6/30/96 16:00	7/18/96 16:00	8/5/96 17:00	7/19/96 15:00	6/16/96 16:00	2/3/96 19:00	7/19/96 16:00	6/30/96 16:00	6/30/96 22:00	1/8/96 8:00	2/5/96 9:00
1997	7/26/97 17:00	7/16/97 19:00	7/17/97 14:00	7/25/97 18:00	7/27/97 17:00	7/26/97 16:00	7/27/97 15:00	7/26/97 17:00	7/27/97 17:00	7/25/97 18:00	7/23/97 15:00
1998	7/21/98 16:00	7/14/98 18:00	7/21/98 17:00	7/20/98 19:00	7/21/98 17:00	7/21/98 17:00	9/6/98 18:00	7/21/98 15:00	7/7/98 19:00	8/1/98 18:00	8/27/98 17:00
1999	7/30/99 17:00	7/24/99 18:00	7/30/99 17:00	7/29/99 17:00	7/18/99 18:00	7/29/99 18:00	7/30/99 17:00	7/6/99 15:00	8/19/99 18:00	8/28/99 17:00	8/19/99 17:00
2000	8/31/00 16:00	6/9/00 19:00	7/13/00 18:00	9/2/00 17:00	8/30/00 17:00	8/17/00 18:00	9/1/00 17:00	6/10/00 16:00	8/30/00 18:00	7/14/00 17:00	8/30/00 17:00
2001	8/9/01 16:00	8/7/01 19:00	8/9/01 16:00	7/22/01 16:00	7/7/01 19:00	8/22/01 16:00	8/6/01 17:00	8/8/01 16:00	7/11/01 17:00	7/10/01 17:00	7/11/01 16:00
2002	7/2/02 16:00	7/6/02 17:00	7/31/02 17:00	7/20/02 17:00	8/22/02 17:00	8/1/02 17:00	8/3/02 17:00	7/31/02 17:00	7/6/02 18:00	8/2/02 16:00	7/10/02 16:00
2003	8/21/03 17:00	8/24/03 19:00	8/21/03 17:00	8/20/03 16:00	8/21/03 17:00	8/21/03 17:00	8/27/03 17:00	8/21/03 17:00	1/24/03 8:00	1/24/03 9:00	1/24/03 10:00
2004	7/21/04 17:00	7/21/04 18:00	7/22/04 14:00	7/21/04 17:00	7/22/04 18:00	8/18/04 18:00	1/30/04 18:00	8/27/04 16:00	7/14/04 18:00	7/24/04 18:00	7/14/04 16:00
2005	7/24/05 18:00	7/17/05 18:00	8/10/05 13:00	7/23/05 17:00	7/24/05 18:00	7/24/05 18:00	8/11/05 16:00	6/28/05 17:00	7/22/05 19:00	7/28/05 17:00	8/21/05 15:00
2006	8/2/06 17:00	7/28/06 16:00	8/1/06 15:00	7/19/06 18:00	8/2/06 19:00	8/2/06 18:00	8/2/06 17:00	8/1/06 14:00	7/19/06 18:00	7/21/06 17:00	8/15/06 17:00
2007	8/8/07 17:00	7/7/07 18:00	7/31/07 16:00	7/18/07 17:00	8/28/07 17:00	8/15/07 17:00	8/29/07 17:00	7/31/07 18:00	8/16/07 17:00	8/8/07 17:00	8/14/07 17:00
2008	7/16/08 17:00	7/11/08 19:00	8/23/08 18:00	8/3/08 19:00	7/18/08 18:00	7/20/08 17:00	8/23/08 17:00	8/24/08 13:00	8/2/08 19:00	7/25/08 16:00	7/27/08 16:00
2009	6/23/09 17:00	5/19/09 19:00	6/24/09 18:00	8/8/09 17:00	8/9/09 18:00	8/9/09 17:00	6/24/09 17:00	8/9/09 16:00	1/16/09 8:00	7/2/09 16:00	7/4/09 16:00
2010	8/3/10 17:00	8/3/10 19:00	7/6/10 15:00	7/14/10 18:00	8/10/10 17:00	8/4/10 17:00	8/10/10 18:00	7/28/10 15:00	8/4/10 21:00	7/30/10 18:00	8/3/10 16:00

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
2011	7/20/11 18:00	7/19/11 18:00	7/20/11 19:00	7/19/11 17:00	9/1/11 17:00	9/1/11 17:00	9/2/11 18:00	7/21/11 14:00	8/3/11 22:00	6/15/11 17:00	8/31/11 17:00
2012	7/6/12 16:00	7/6/12 18:00	7/5/12 14:00	7/25/12 16:00	7/6/12 17:00	6/28/12 19:00	7/7/12 17:00	7/6/12 15:00	7/30/12 20:00	6/26/12 17:00	7/29/12 17:00
2013	7/17/13 16:00	8/24/13 17:00	7/17/13 16:00	8/30/13 19:00	7/19/13 17:00	8/31/13 17:00	7/18/13 16:00	9/11/13 14:00	6/27/13 19:00	7/29/13 17:00	8/9/13 16:00
2014	7/22/14 17:00	7/21/14 18:00	7/8/14 17:00	9/4/14 16:00	8/25/14 17:00	8/25/14 17:00	1/6/14 20:00	6/17/14 16:00	1/7/14 8:00	1/6/14 21:00	1/7/14 10:00
2015	7/29/15 17:00	8/14/15 18:00	8/14/15 17:00	7/17/15 18:00	7/28/15 18:00	7/28/15 17:00	9/4/15 16:00	9/2/15 17:00	7/29/15 18:00	7/29/15 17:00	7/30/15 14:00
2016	7/21/16 16:00	7/21/16 17:00	8/4/16 16:00	7/10/16 15:00	7/23/16 16:00	7/23/16 16:00	8/10/16 16:00	8/4/16 14:00	7/21/16 15:00	7/3/16 14:00	7/20/16 15:00
2017	7/20/17 16:00	7/15/17 17:00	7/20/17 14:00	7/21/17 17:00	7/21/17 16:00	7/22/17 17:00	8/20/17 16:00	9/21/17 14:00	7/21/17 17:00	7/27/17 15:00	7/19/17 15:00
2018	7/10/18 15:00	7/12/18 15:00	8/4/18 15:00	7/12/18 16:00	9/5/18 16:00	7/14/18 14:00	7/13/18 16:00	9/5/18 15:00	1/16/18 9:00	7/22/18 16:00	1/18/18 8:00
2019	7/19/19 16:00	7/19/19 17:00	8/7/19 15:00	7/19/19 19:00	7/10/19 16:00	1/30/19 19:00	7/20/19 16:00	7/20/19 14:00	8/7/19 15:00	7/5/19 16:00	10/2/19 15:00
2020	7/2/20 15:00	8/26/20 16:00	7/8/20 16:00	8/28/20 15:00	7/9/20 16:00	7/11/20 16:00	7/5/20 15:00	7/3/20 15:00	7/2/20 17:00	7/11/20 15:00	7/22/20 15:00
2021	7/28/21 16:00	7/28/21 17:00	7/28/21 15:00	6/17/21 16:00	6/18/21 15:00	6/18/21 15:00	8/24/21 16:00	8/26/21 15:00	7/8/21 17:00	7/28/21 15:00	6/13/21 14:00
2022	6/21/22 16:00	8/2/22 18:00	6/21/22 16:00	7/23/22 14:00	7/5/22 16:00	7/23/22 16:00	7/5/22 16:00	6/21/22 16:00	7/26/22 16:00	12/23/22 9:00	6/25/22 15:00
2023	8/24/23 16:00	8/22/23 18:00	8/23/23 16:00	8/24/23 16:00	8/24/23 16:00	8/25/23 15:00	8/24/23 16:00	7/28/23 16:00	7/29/23 16:00	8/27/23 15:00	8/24/23 15:00
2024	7/31/24 15:00	8/25/24 18:00	7/31/24 15:00	8/4/24 16:00	8/27/24 17:00	6/25/24 14:00	8/30/24 16:00	8/1/24 15:00	1/16/24 8:00	1/17/24 8:00	8/18/24 15:00

Table 3-15: Modeled Peak Demand Days/Hours by Zone

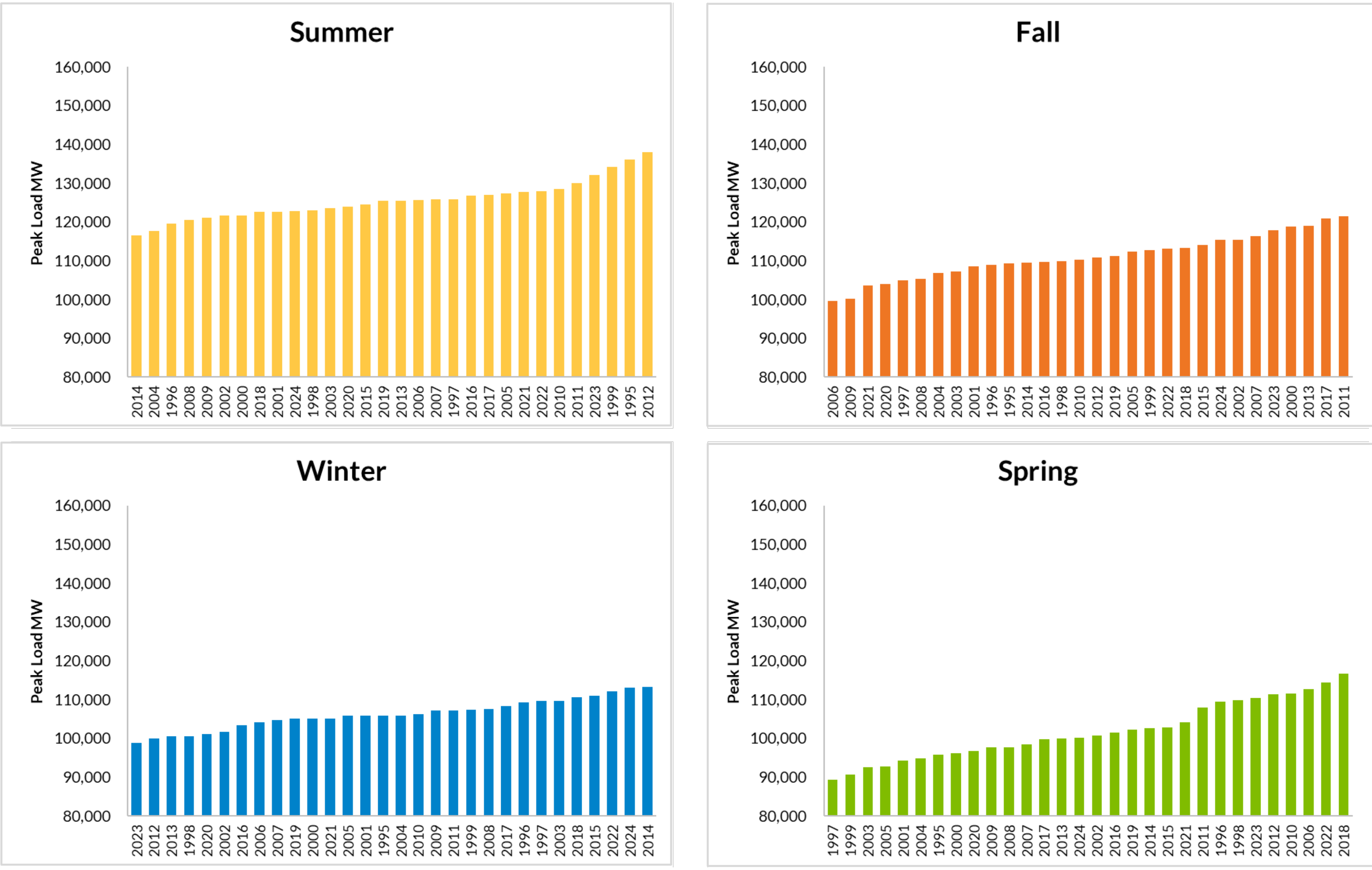


Figure 3-8: Seasonal Peak Load Variability for MISO in Prompt Planning Year

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), if applicable. 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 2025-2026 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 seasonal 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 3-16 shows the number of firm import and export MW values in this year's study. Based on data from the Planning Year 2025-2026 PRA, MISO became a net firm exporter which differed from the prior year's study and was largely driven by reductions in firm imports from the PJM region.

Contracts	Summer UCAP (MW)	Fall UCAP (MW)	Winter UCAP (MW)	Spring UCAP (MW)
Imports (MW)	-1,088	-1,034	-1,282	-1,036
Exports (MW)	1,161	1,155	1,842	1,639
Net	**73**	**121**	**560**	**603**

Table 3-16: Planning Year 2026-2027 Firm Imports and Exports

Non-firm imports in the Planning Year 2026-2027 LOLE study were modeled as a seasonal probabilistic distribution representing an average of the last five years of 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 historical seasonal Net Scheduled Interchange (NSI) data which accounted for imports into MISO during all pricing hours. Firm imports that FRAP'd or 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 3-17. Lastly, it is important to note that values of 0 in the distribution table represent periods when MISO would be exporting off system. However, since there is no load associated with the non-firm support region in the LOLE model, these exports do not occur. For this reason, hours of export have been replaced with a zero to display how they occur in the model simulations.

	Summer	Fall	Winter	Spring
p5	0	0	0	0
p10	311	0	0	2
p25	1,445	220	154	802
p50	2,867	1,478	1,349	1,848
p75	4,302	2,825	2,661	2,923
p90	5,369	4,014	3,974	4,113
p95	6,000	4,675	4,778	4,906

Table 3-17: Non-Firm External Import Distribution During All Pricing Hours (MW)

3.6 Cold Weather Outages

Additional thermal outages are added to the LOLE model during times of extreme cold temperature to better capture the magnitude of outages that occur across the MISO system outside of planned maintenance and standard forced outages. Profiles to represent these outages were developed by PowerGEM and are derived through correlated relationships from the most recent five years of forced outage historical GADS data and weather data (2020-2024). These profiles represent the incremental cold weather outages that may occur for six resource classes across MISO's ten LRZs. They are not assigned to any particular resource but instead represent the aggregate impact on the system for their assigned resource class.

To determine the values used in the PRM calculation, an average ELCC analysis is conducted on the cold weather outages, and the resulting UCAP is subtracted from the system-wide UCAP for each season. This impact is then distributed pro-rata to the zonal level based on the average magnitude of the zonal cold weather outages that were determined and is used in the LRR calculations. The ELCC analysis for the PY 2026-2027 LOLE Study resulted in increased impacts from these outages with comparison to the prior year's study and showed the largest effects occurring in the Winter (11.3 GW) and Spring (7.9 GW) seasons, with minimal effects on the Fall season (830 MW). The Summer season was not affected by these outages. Increases in cold weather outages occurred due to larger correlations between forced outages and cold weather seen in the 2020-2024 PowerGADs data.

Figure 3-9 shows an overall comparison of the profile changes that occurred across the MISO system in this year's prompt year analysis verse the prior year.

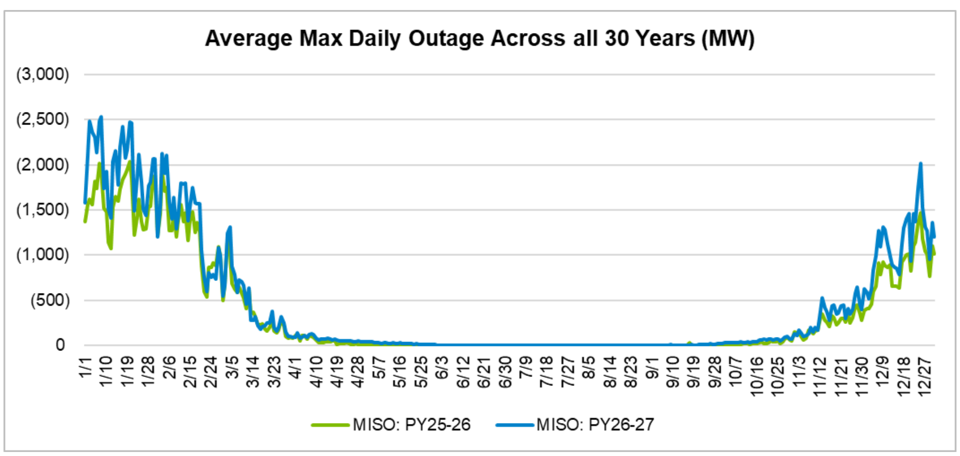


Figure 3-9: Prompt Year Cold Weather Outage Comparison with Prior Planning Year

Additionally, cold weather outages are included in the four- and six-year models. However, certain units were assumed unavailable in the outyear model and their impact on the cold weather outages were removed from the profiles. This resulted in slight reductions to cold weather outages observed in both the four- and six-year models, as shown in Figure 3-10.

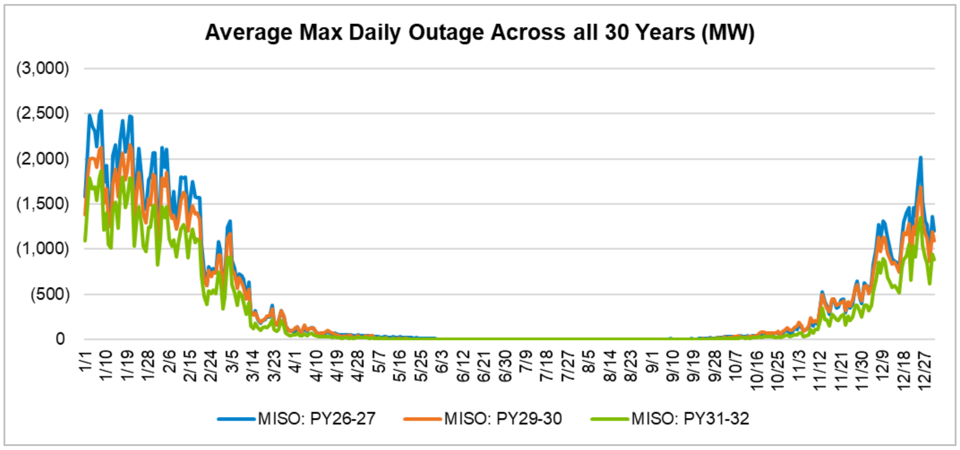


Figure 3-10: Cold Weather Outage Comparisons for all Study Years within PY 2026-2027 LOLE Study

3.7 Loss of Load Expectation Metric Calculation Definitions

Upon completion of the annual LOLE study, MISO performed probabilistic analyses to determine the seasonal PRM values for PY 2026-2027, as well as the seasonal LRR values for each of the 10 LRZs. The risk metrics were derived through probabilistic modeling of the system, first solving to the reliability metric threshold of annual LOLE risk criteria 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, or 1 day in 100 years, for seasons that did not meet that threshold in the annual simulation.

3.7.1 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 exhibited 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 an 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.*

Each year, MISO analyzes the seasonal risk distribution and represents this through a heatmap of the EUE that occurs in any hour throughout the entire 30-year simulation. The values in Figure 3-11 are weighted by the associated simulated probability and the number of iterations. Values of 0% represent hours where risk was observed but did not contain enough EUE to receive higher than 0% of the season's total EUE. Percentages in the Month % row represent the share of EUE for each month of its respective season.

PY 2025-2026
Seasonal Loss of Load Risk Distribution

Hour	Summer			Fall			Winter			Spring		
	6	7	8	9	10	11	12	1	2	3	4	5
1												
2												
3												
4												
5												
6												
7												
8								13%	0%	11%		
9						0%		42%	2%	30%		
10						0%		17%		2%		
11						0%		18%		1%		
12						0%		5%		17%		
13		0%				0%		2%		1%		
14		1%	0%									
15		3%	0%									
16		7%	0%	0%								
17		11%	0%	1%								0%
18		19%	1%	16%								3%
19		26%	1%	39%		1%		0%		2%		6%
20		21%	1%	33%		2%		0%	1%	17%		8%
21		11%	0%	0%		1%		0%	0%	1%		1%
22		0%				7%		0%				
23												
24												
Month %	0%	97%	3%	90%	0%	10%	0%	97%	3%	82%	0%	18%
LOLE	0.1			0.01			0.01			0.01		

PY 2026-2027
Seasonal Loss of Load Risk Distribution

Hour	Summer			Fall			Winter			Spring		
	6	7	8	9	10	11	12	1	2	3	4	5
1												
2												
3												
4												
5												
6						0%		0%				
7						1%		1%	0%	4%		
8						31%	0%	10%	6%	96%		
9						2%	0%	17%	3%			
10						0%		0%		0%		
11								0%				
12								0%				
13												
14		0%										
15		0%										
16		2%										
17		3%	0%									
18		9%	0%	0%								
19		18%	1%	14%	0%				2%			
20		32%	1%	35%		0%			6%			
21		27%	0%	10%		0%			13%			
22		8%		1%		1%			16%			
23		0%				2%			17%			
24						1%			9%			
Month %	0%	99%	1%	61%	0%	38%	0%	28%	72%	100%	0%	0%
LOLE	0.076			0.01			0.014			0.01		

Figure 3-11: Seasonal Loss of Load Risk Distribution Year-Over-Year Comparison

3.7.2 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 % = (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)

3.7.3 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 2026-2027 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 % = (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 2026-2027. 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 added to seasonal ZIA to determine seasonal CIL values. The objective of the transfer analysis 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
    - 208 new machines added to the system resulted in 19 GW of new nameplate
    - 107 machines removed resulted in 7 GW of lost nameplate, primarily due to cancelled GIAs
    - This turnover results in changes to generation dispatch, base flows, & transmission line loadings
- Transmission
    - 1000 + Transmission Projects at $16B coming online by June 1, 2027
- Demand
    - 4% increase in Summer, 8% Fall, 7% Winter, and 10% Spring

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. Sensitivities would only be accepted for a particular zone if they are in a situation like that seen in Figure 4-1.

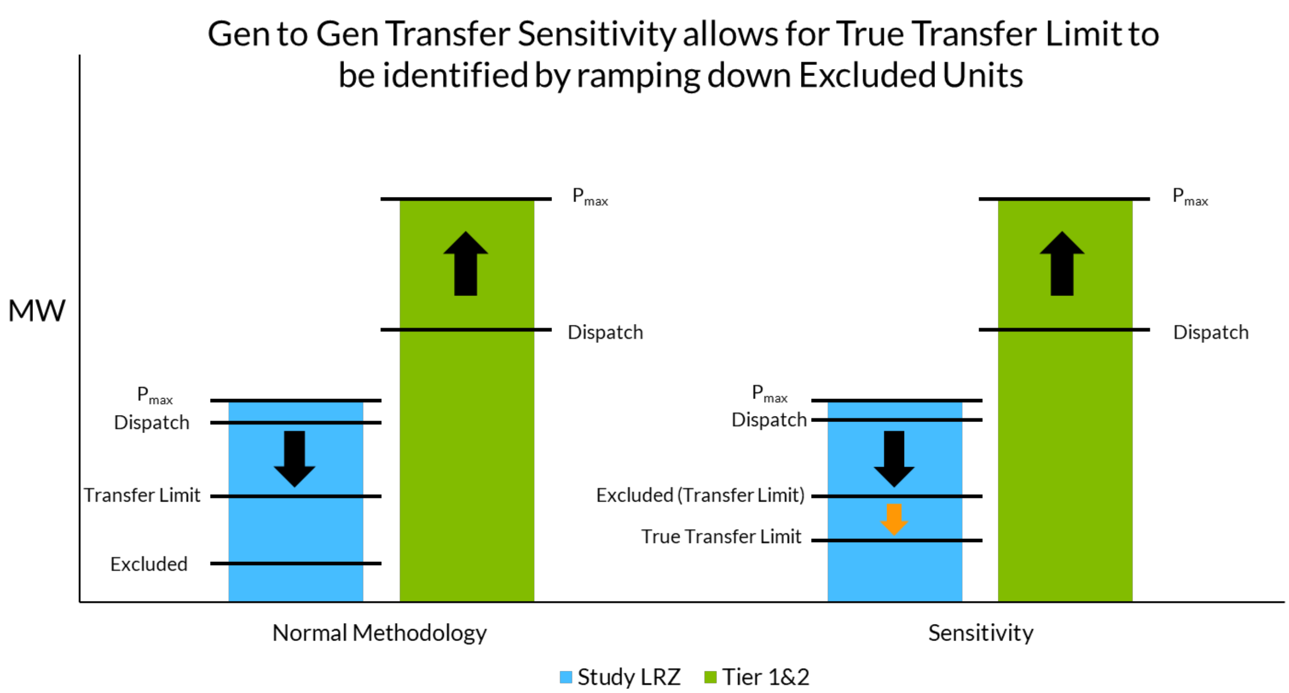


Figure 4-1: Generation-to-Generation Transfer Sensitivity

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 2026-2027.

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 2026-2027, 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 2026-2027.

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[7] 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 2026	July 15th	MTEP Appendix A and Target A	ERAG MMWG 2024 Series 2026 Summer Peak Load Model	Summer Peak	20.8%	50%
Fall 2026	October 15th	MTEP Appendix A and Target A	ERAG MMWG 2024 Series 2026 Spring Light Load Model	Fall Peak	30.7%	50%
Winter 2026-2027	January 15th	MTEP Appendix A and Target A	ERAG MMWG 2024 Series 2026 Winter Peak Load Model	Winter Peak	67%	0%
Spring 2027	April 15th	MTEP Appendix A and Target A	ERAG MMWG 2024 Series 2026 Spring Light Load Model	Spring Peak	25.3%	50%

Table 4-1: Powerflow 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 MTEP25 analyses, with study files made available on MISO ShareFile. 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.

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

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

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

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

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

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 2026-2027 presented at the October 30, 2025 meeting. Table 4-3 shows the Planning Year 2026-2027 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.

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

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

The ZIA, ZEA, CIL, and CEL values are subject to updates in March 2026 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.

LRZ1	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2026	Tiffin - Morgan Valley 345 kV	Salem - Rock Creek 345 kV	None	852 MWx2	7042	7044
Fall 2026	Stone Lake 345/161 kV Transformer	Superior - Stone Lake 345 kV	None	721 MWx2	7244	7296
Winter 2026-27	Pleasant Valley - Byron 161 kV	Pleasant Valley - Byron 345 kV	None	1000 MWx2	4533	5135
Spring 2027	Watertown - Erec-Blair 230 kV	Astoria - Astoria North 345 kV	None	580 MWx2	6690	6892
LRZ2	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2026	Elk Mound - Prairie View 161 kV	Eau Claire - AS King 345 kV	None	651 MWx2	5072	5072
Fall 2026	Arpin - Siegel 138 kV	Arpin - Rocky Run 345 kV	None	662 MWx2	6050	6050
Winter 2026-27	Elk Mound - Prairie View 161 kV	Eau Claire - AS King 345 kV	None	699 MWx2	5294	5381
Spring 2027	Arpin - Siegel 138 kV	Arpin - Rocky Run 345 kV	None	460 MWx2	6133	6133
LRZ3	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2026	Sub 3458 (Nebraska City) - Sub 3456 345 kV	Sub 3458 (Nebraska City) - Sub 3740 345 kV	None	265 MWx2	5400	5495
Fall 2026	None	None	None	1000 MWx2	9191	9284
Winter 2026-27	None	None	None	434 MWx2	9620	9712
Spring 2027	None	None	None	1000 MWx2	9311	9414
LRZ4	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2026	None	None	20%	N/A	8517	9285
Fall 2026	Palmyra - Marblehead North 161 kV	Herleman - Palmyra Tap 345 kV	None	893 MWx2	6491	7251
Winter 2026-27	Sandburg 161/138 kV Transformer	Sandburg - Oak Grove 345 kV	None	795 MWx2	5493	6268
Spring 2027	None	None	20%	N/A	6533	7302
LRZ5	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2026	Lansing - Genoa 161 kV	Lansing 161/69 kV Transformer	None	655 MWx2	4417	4417
Fall 2026	None	None	50%	N/A	4762	4762
Winter 2026-27	Overton 345/161 kV Transformer	McCredie - Overton 345 kV	None	265 MWx2	6379	6379
Spring 2027	None	None	50%	N/A	4733	4733
LRZ6	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2026	Joppa South - Joppa South Tap 161 kV	Joppa South - Grahmville 345 kV	None	865 MWx2	6440	6725
Fall 2026	Joppa South Tap - Mass 161 kV	Joppa North - Mass 161 kV	None	1000 MWx2	7012	7292
Winter 2026-27	Sugar Creek - Dresser 345 kV	Cayuga - Nucor 345 kV	None	1000 MWx2	8208	8445
Spring 2027	Sugar Creek - Dresser 345 kV	Merom #2 Generator	None	1000 MWx2	7999	8280
LRZ7	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2026	Pere Marquette 345/138 kV Transformer	Keystone - Ludington 345 kV	None	1000 MWx2	4628	4628
Fall 2026	Pere Marquette 345/138 kV Transformer	Keystone - Ludington 345 kV	None	1000 MWx2	5193	5193
Winter 2026-27	Univ. Pk. N. - P9701 West 345 kV	Dumont - Wilton 765 kV	None	1000 MWx2	4123	4123
Spring 2027	Argenta - 18OXBY 345 kV	Argenta - Battle Creek 345 kV	None	1000 MWx2	5338	5338
LRZ8	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2026	MEPS Clarkesdale - Moon Lake 230 kV	Tunica - J1440 POI 115 kV	None	579 MWx2	3981	4191
Fall 2026	West Memphis 500/161 kV Transformer	Sandy Bayou - Shelby 500 kV	None	1000 MWx2	6170	6334
Winter 2026-27	Little Gypsy - Fairview 230 kV	Michoud - Front Street 230 kV	None	762 MWx2	3366	3547
Spring 2027	Mount Olive - Vienna 115 kV	Mount Olive - El Dorado 500 kV	None	1000 MWx2	5374	5578
LRZ9	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2026	Danvile - Dodson 115 kV	Mount Olive - Layfield 500 kV	None	1000 MWx2	4309	4309
Fall 2026	Danvile - Dodson 115 kV	Mount Olive - Layfield 500 kV	None	1000 MWx2	4761	4761
Winter 2026-27	Greenville - Greenville Southeast 115 kV	Gerald Andrus - J1458 POI (Greer Solar) 230 kV	None	1000 MWx2	3690	3690
Spring 2027	Franklin - McKnight 500 kV	River Bend Unit 1 Generator	None	1000 MWx2	4657	4657
LRZ 10	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2026	Moon Lake - Six Mile Lake 230 kV	Batesville Unit 3 Generator	None	542 MWx2	5322	5322
Fall 2026	Perryville - Baxter Wilson 500 kV	Grand Gulf Generator	None	404 MWx2	4379	4379
Winter 2026-27	Perryville - Baxter Wilson 500 kV	Grand Gulf Generator	None	413 MWx2	3154	3154
Spring 2027	Perryville - Baxter Wilson 500 kV	Grand Gulf Generator	None	456 MWx2	4187	4187

Table 4-3: Planning Year 2026–2027 Import Limits

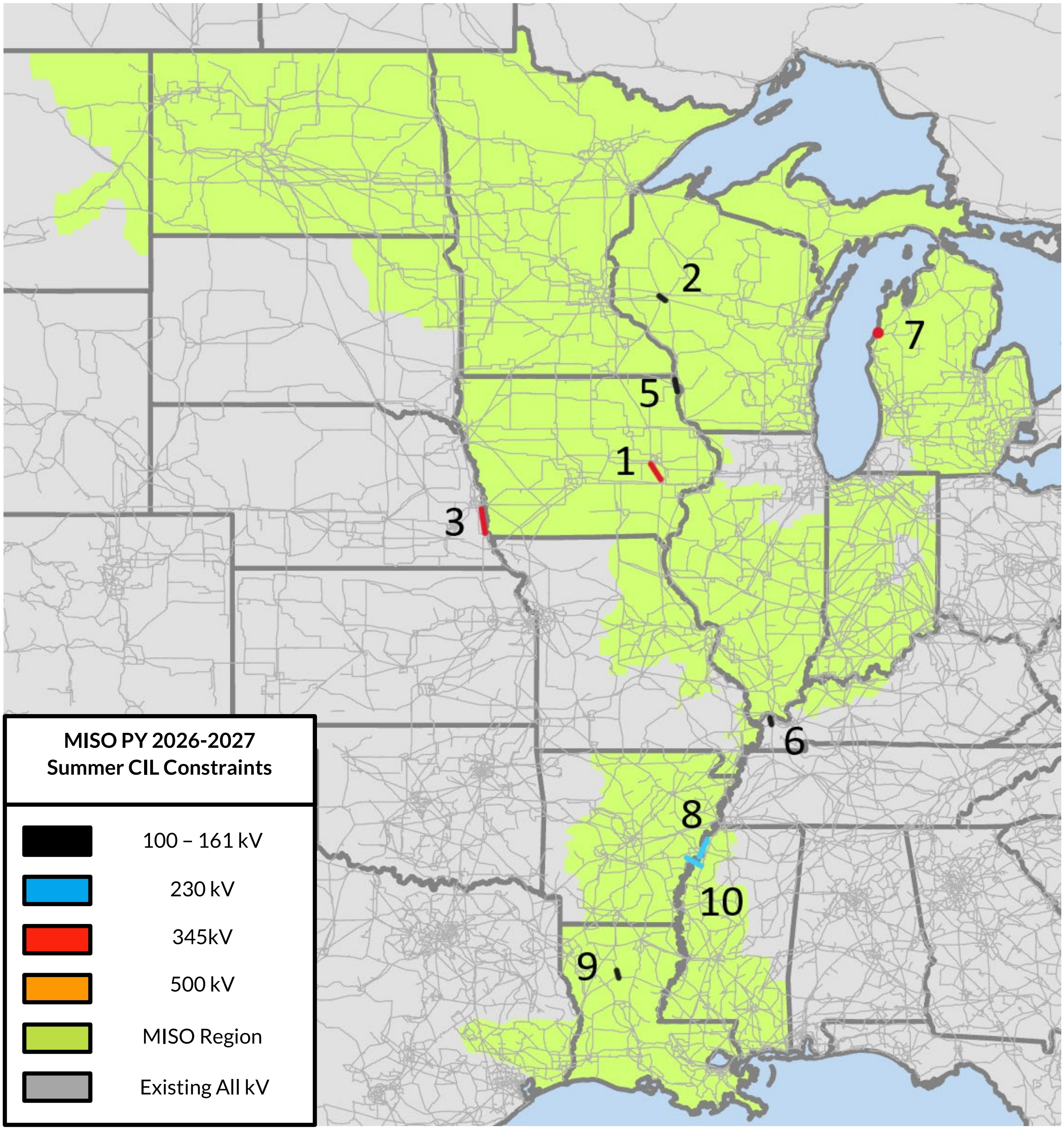


Figure 4-2: Planning Year 2026-2027 Summer Capacity Import Constraints Map

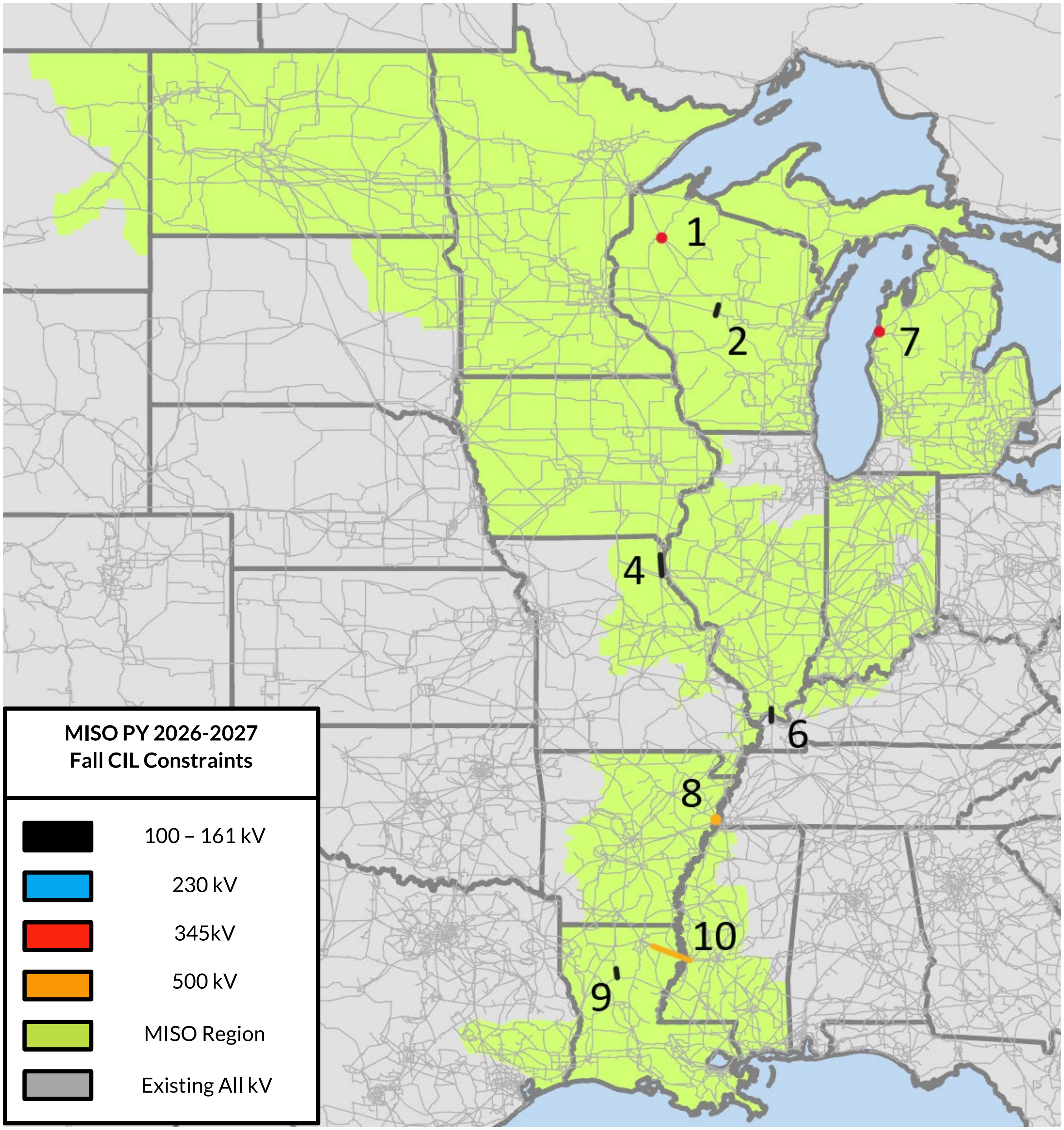


Figure 4-3: Planning Year 2026-2027 Fall Capacity Import Constraints Map

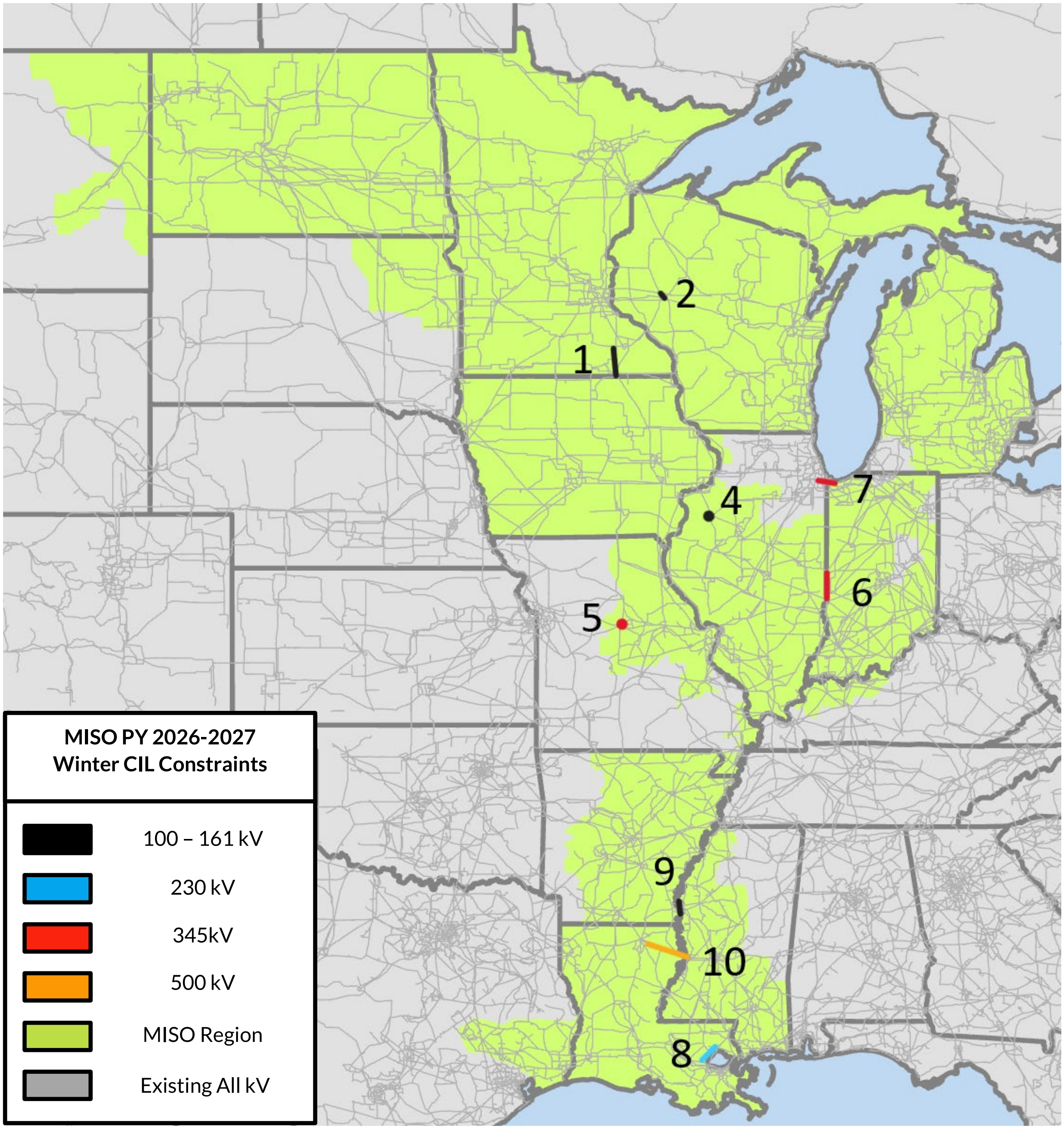


Figure 4-4: Planning Year 2026-2027 Winter Capacity Import Constraints Map

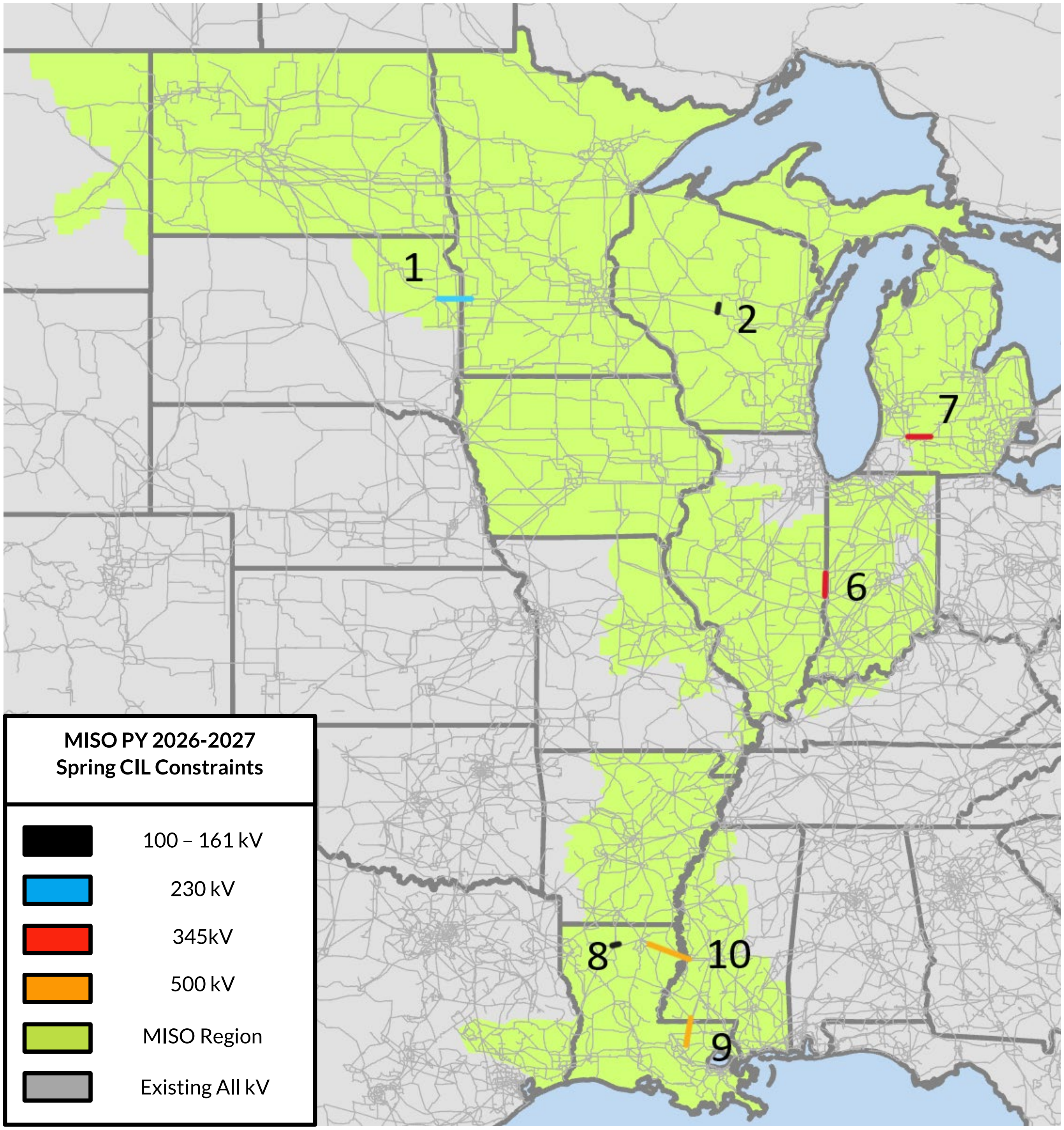


Figure 4-5: Planning Year 2026-2027 Spring Capacity Import Constraints Map

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 2026-2027 CEL and ZEA with corresponding constraint, GLT, and redispatch information.

LRZ1	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2026	Elk Mound - Prairie View 161 kV	Eau Claire - King 345 kV	15%	300 MWx2	3720	3718
Fall 2026	Adams 345/161 kV Transformer	Adams - Pleasant Valley 345 kV	None	1000 MWx2	4199	4147
Winter 2026-27	Raun - S3451 345 kV	Grimes - Beaver Creek 345 kV	None	811 MWx2	2987	2385
Spring 2027	Adams 345/161 kV Transformer	Adams - Pleasant Valley 345 kV	None	671 MWx2	3715	3513
LRZ2	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2026	Sherman Street - Sunnyvale 115 kV	Arpin - Rocky Run 345 kV	20%	330 MWx2	3088	3088
Fall 2026	Germantown Bus6 - Bark River 138 kV	Germantown - Maple 138 kV	15%	1000 MWx2	5034	5034
Winter 2026-27	Paris - Berryville 138 kV	Paris 345/138 kV Transformer	5%	1000 MWx2	3945	3858
Spring 2027	Paris - Berryville 138 kV	Paris 345/138 kV Transformer	None	1000 MWx2	4608	4608
LRZ3	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2026	Lansing East - Genoa 161 kV	Lasning East - Harmony 161 kV	40%	190 MWx2	5133	5038
Fall 2026	Lansing East - Genoa 161 kV	Harmony - Genoa 161 kV	30%	812 MWx2	5744	5651
Winter 2026-27	Univ. Pk. N. - P9701 West 345 kV	Dumont - Wilton 765 kV	None	1000 MWx2	9285	9193
Spring 2027	Sandburg 161/138 kV	Sandburg - Oak Grove 345 kV	30%	472 MWx2	6391	6288
LRZ4	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2026	None	None	50%	N/A	8225	7457
Fall 2026	Joppa South - Mass 161 kV	Joppa North - Mass 161 kV	15%	1000 MWx2	6611	5851
Winter 2026-27	Joppa South - Mass 161 kV	Joppa North - Mass 161 kV	None	1000 MWx2	4724	3949
Spring 2027	Joppa South - Mass 161 kV	Joppa North - Mass 161 kV	10%	118 MWx2	6447	5678
LRZ5	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2026	None	None	50%	N/A	5255	5255
Fall 2026	None	None	50%	N/A	3701	3701
Winter 2026-27	Spencer Creek - Vanhorn 345 kV	Palmyra Tap - Spencer Creek 345 kV	20%	1000 MWx2	6786	6786
Spring 2027	None	None	50%	N/A	5811	5811
LRZ6	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2026	Wilson - Matanzas 161 kV	Green River - Wilson 161 kV	40%	113 MWx2	7744	7459
Fall 2026	Whiting Clean Energy - Praxair 6 138 kV	Marktown East - Whiting Clean Energy 138 kV	None	313 MWx2	5461	5181
Winter 2026-27	Holland - Dubois 138 kV	Duff - Francisco 345 kV	10%	923 MWx2	3378	3141
Spring 2027	Luchtman Road - Flint Lake 138 kV	Shoreline - Ridgeway 138 kV	None	1000 MWx2	4465	4184
LRZ7	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2026	Segreto - Benton Harbor 345 kV	Cook - Segreto 345 kV	15%	445 MWx2	5745	5745
Fall 2026	Monroe 1&2 - Lallendorf 345 kV	Morocco - Allen Jct 345 kV	None	1000 MWx2	5305	5305
Winter 2026-27	Morocco - Allen Jct 345 kV	Monroe 1&2 - Lallendorf 345 kV	None	696 MWx2	5546	5546
Spring 2027	Segreto - Benton Harbor 345 kV	Cook - Segreto 345 kV	None	1000 MWx2	5497	5497
LRZ8	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2026	Arklahoma - Hot Springs East 115 kV	Arklahoma - Hot Springs West 115 kV	40%	1000 MWx2	5403	5193
Fall 2026	Arklahoma - Hot Springs East 115 kV	Arklahoma - Hot Springs West 115 kV	None	1000 MWx2	3947	3783
Winter 2026-27	Arklahoma - Hot Springs East 115 kV	Arklahoma - Hot Springs West 115 kV	25%	1000 MWx2	4609	4428
Spring 2027	Freeport - Cordova 500 kV	Sans Souci - Driver 500 kV	None	1000 MWx2	4144	3940
LRZ9	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2026	Winnfield 230/115 kV Transformer	Montgomery - Clarence 230 kV	None	1000 MWx2	3361	3361
Fall 2026	Winnfield 230/115 kV Transformer	Montgomery - Clarence 230 kV	None	1000 MWx2	3970	3970
Winter 2026-27	Moss Point East - North Theodore 230 kV	Big Creek - Daniel 230 kV	None	1000 MWx2	2096	2096
Spring 2027	Winnfield 230/115 kV Transformer	Montgomery - Clarence 230 kV	None	1000 MWx2	4633	4633
LRZ10	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2026	Plant Moselle - MS Solar 4 161 kV	Plant Mosell - Cole Road 161 kV	None	612 MWx2	2132	2132
Fall 2026	Andrus 230/115 kV Transformer	Andrus - Indianola 230 kV	None	945 MWx2	2459	2459
Winter 2026-27	Greenville - Leland 115 kV	Andrus - Indianola 230 kV	None	1000 MWx2	1602	1602
Spring 2027	Clarksdale - Lyon 115 kV	MEPS Clarksdale - Moon Lake 230 kV	None	581 MWx2	2725	2725

Table 4-4: Planning Year 2026–2027 Export Limits

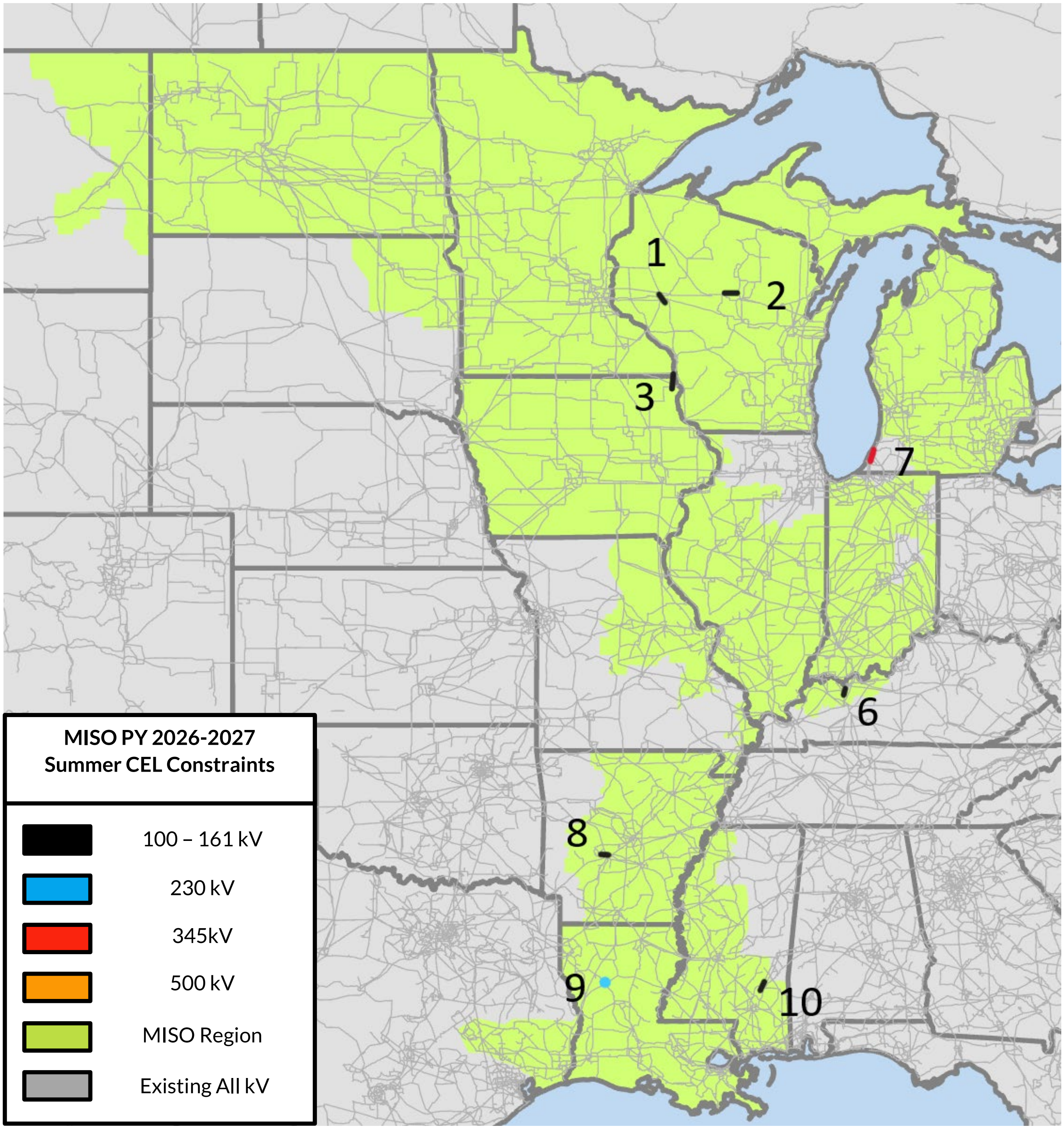


Figure 4-6: Planning Year 2026-2027 Summer Export Constraint Map

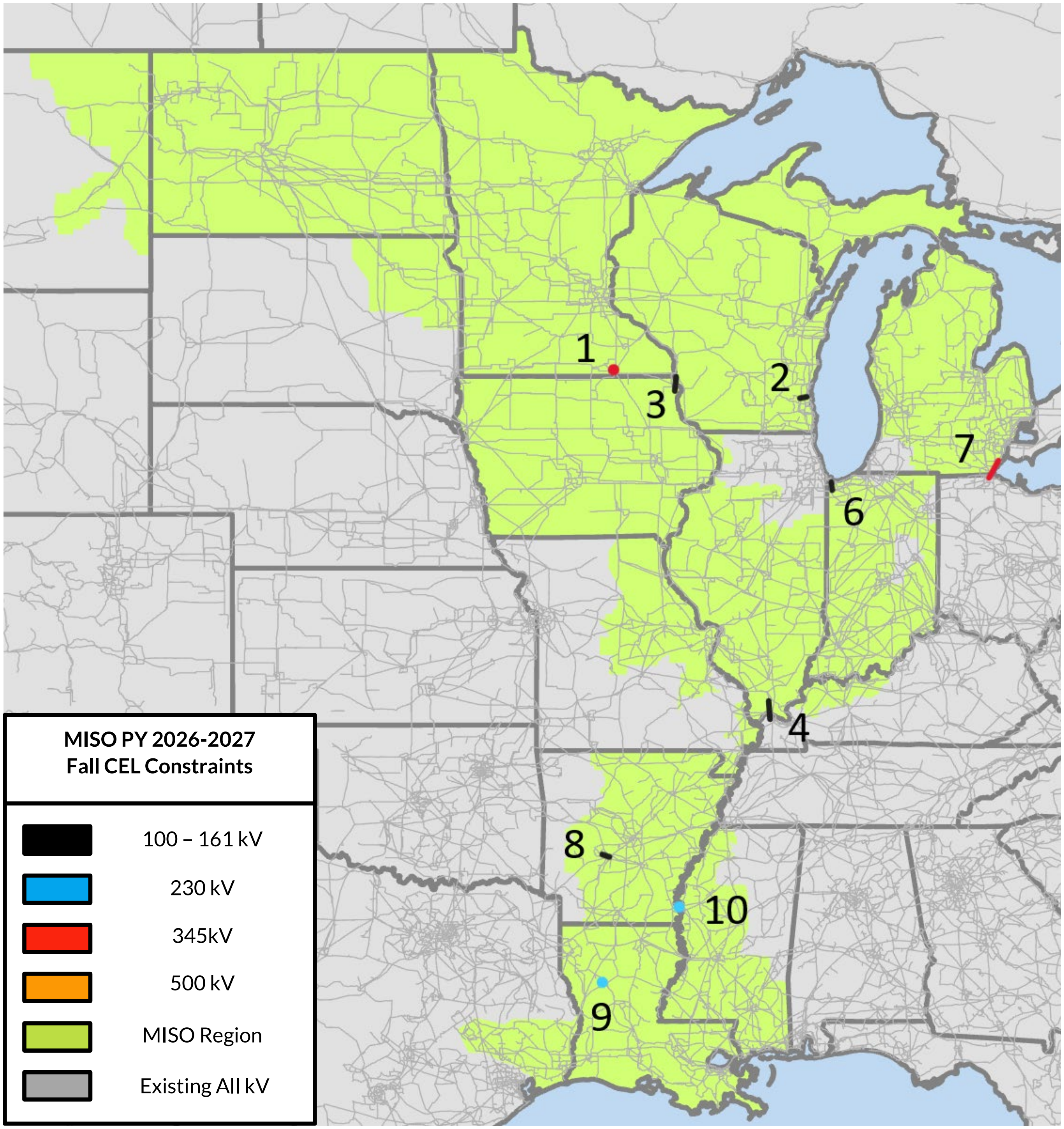


Figure 4-7: Planning Year 2026-2027 Fall Export Constraint Map

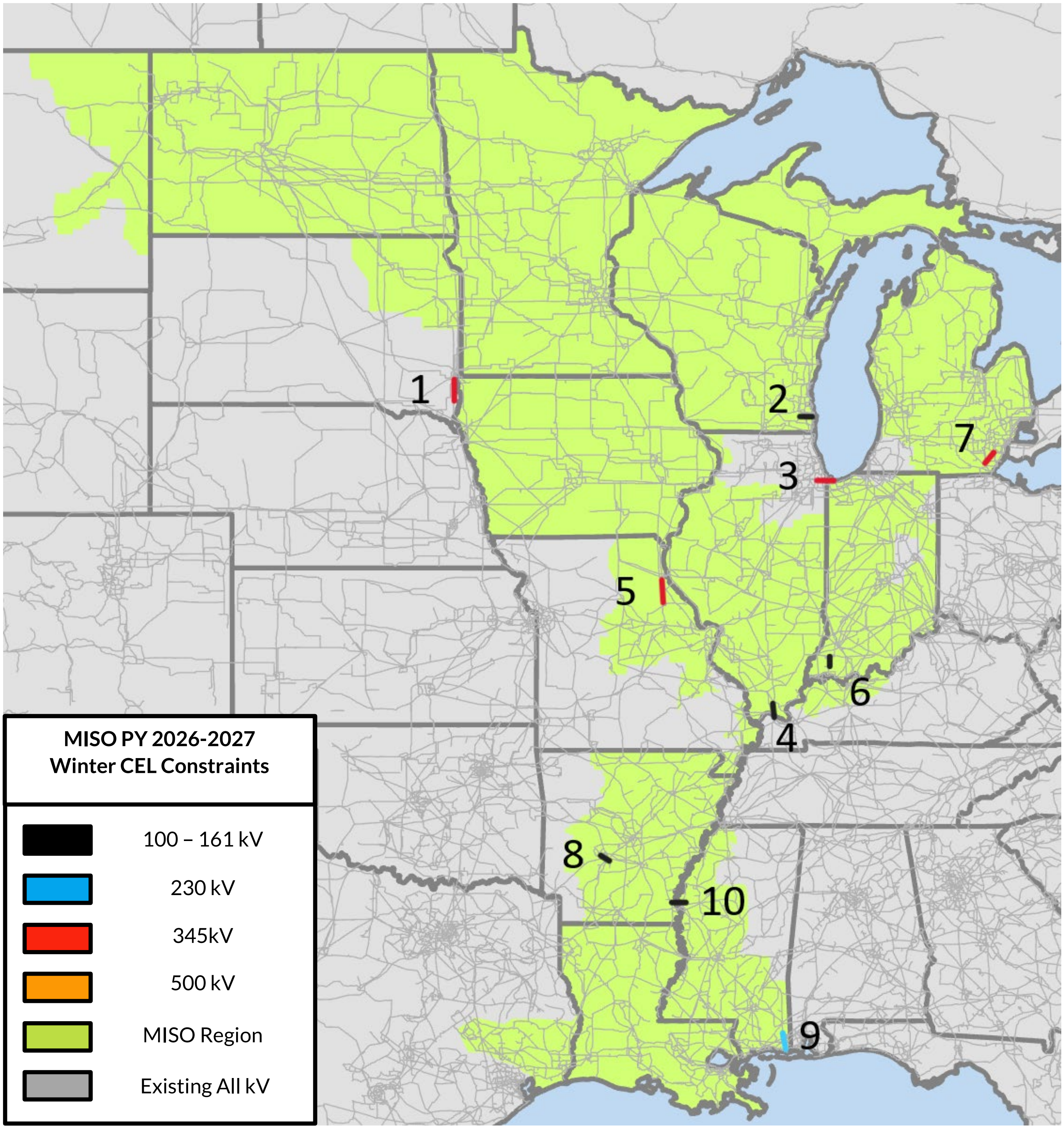


Figure 4-8: Planning Year 2026-2027 Winter Export Constraint Map

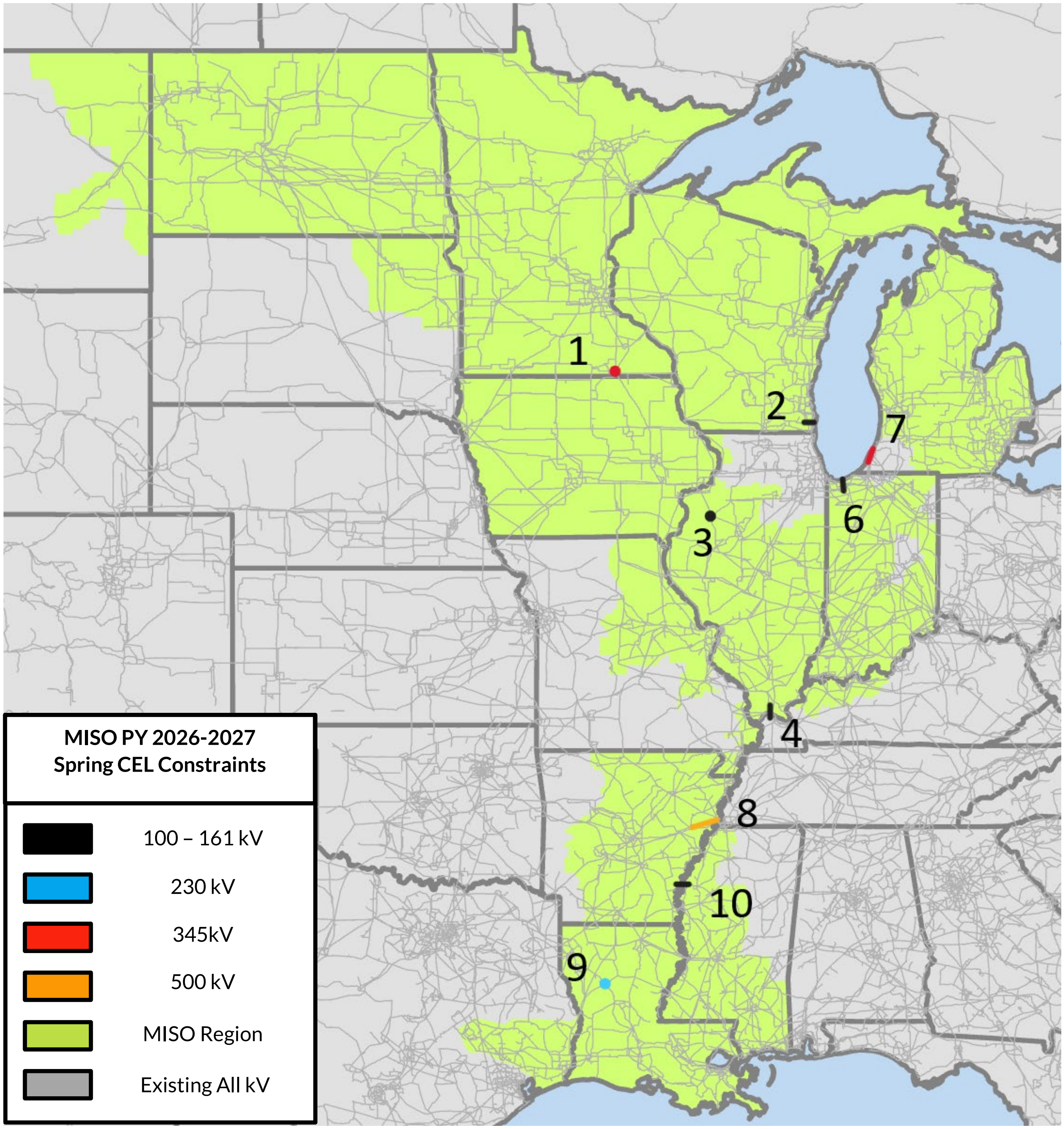


Figure 4-9: Planning Year 2026-2027 Spring Export Constraint Map

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	GLH / 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	
GLH / 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	XEL / 600
AMMO / 356	GLH / 362	DEI / 208	SMMPA / 613
	ALTW / 627	NIPS / 217	MPW / 633
	MEC / 635	BREC / 314	DPC / 680
		CWLP / 360	ALTE / 694
		SIPC / 361	

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	GLH / 362	CWLP / 360
NIPS / 217		ALTW / 627
BREC / 314		MEC / 635
HMPL / 315		

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	SMEPA / 349
	LAGT / 331	CLEC / 502
	EES / 351	LAFA / 503

MISO Local Resource Zone 9

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
LAGT / 331	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	LAGT / 331
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 2026-2027 LOLE Study Report is the annual Resource Adequacy Analysis for the peak season of June 2026 through May 2027 and beyond. Analysis of Planning Year 2026-2027 is in Sections 1 and 2. Analysis of Future Years 2026-2035 will be included in Appendix D as an addendum to the study report in Q1 2026.
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 3.7 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 reliability metric threshold of annual LOLE risk criteria 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, or 1 day in 100 years, for seasons that did not meet that threshold in the annual simulation."
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 of this report. "…the ratio of MISO Unforced Capacity to forecasted MISO system peak demand yielded a Planning 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 1 and 2, a full analysis was performed for Planning Year 2026-2027.
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 2029-2030 and 2031-2032 will be included in Appendix D as an addendum to the study report in Q1 2026.

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 final step of the load training process is to ensure that the average monthly peak load across all 30 years of the predicted load shape matches each LRZ's total monthly zonal Coincident Peak Demand forecast provided by the Load Serving Entities for each study year." 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 next LOLE study to align the load in the model with the anticipated load growth forecasted within each Local Resource Zone." "The LOLE analyses used a load training process paired with neural net software to establish a correlated relationship between the most recent five years of historical weather and load data. Correlated relationships are developed from the time of day, temperature, and load values observed in the five year data set. 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 3.2.7: "Each demand response program was modeled individually with a seasonal 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 3.2.7. The effects of resource outage characteristics on the reserve margin are outlined in Section 3.7.2 by examining the difference between PRM ICAP and PRM 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, 2, and 3.3.
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, 2, and 3.4.2.
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 amounts of resources for Planning Year 2026-2027 are shown. This includes the details for each transmission constrained sub-area.
R2.1 This documentation covers each of the years in year one through ten.	Appendix D will detail the future Planning Year analyses in Q1 2026.

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. The outyear Planning Years 4 (2029-2030) and 6 (2031-2032) will be covered in Appendix D in Q1 2026.
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 Planning Year 2026-2027 LOLE Study Report was posted publicly in November 2025, 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 2026-2027. The amount of planning reserves needed for the outyear Planning Years 4 (2029-2030) and 6 (2031-2032) will be covered in Appendix D in Q1 2026.

Appendix C: Acronyms List Table

CEL	Capacity Export Limit
CIL	Capacity Import Limit
CPNode	Commercial Pricing Node
DF	Distribution Factor
DLOL	Direct Loss of Load
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
FRAP	Fixed Resource Adequacy Plan
GADS	Generator Availability Data System
GLT	Generation Limited Transfer
GVTC	Generation Verification Test Capacity
GW	Gigawatt
GWh	Gigawatt hours
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
LOLH	Loss of Load Hours
LRR	Local Reliability Requirement
LRZ	Local Resource Zones
LSE	Load Serving Entity
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	PRM Unforced Capacity
PRMR	Planning Reserve Margin Requirement
PSSE	Power System Simulator for Engineering
RAR	Resource Adequacy Requirements
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

Planning Year 2029-2030 and Planning Year 2031-2032 Planning Reserve Margin and supporting values will be published in Q1 2026.

D.1 MISO Outyear Projected Capacity

The following charts and tables below detail the total Installed Capacity (ICAP) values by resource type and LRZ in the PY 2029-2030 and PY 2031-2032 LOLE models. Starting with the PY 2026-2027 LOLE study, it was decided through conversations with stakeholders that MISO-OMS high certainty retirements would be included in MISO's outyear LOLE models to better represent the changing dynamics of the energy system in the coming years. This topic was introduced to stakeholders at the April LOLEWG and feedback was requested. The resulting feedback was supportive of this direction and resulted in additional retirements of 13.5 ICAP GW in outyear four and 22.5 ICAP GW of retirements in outyear six. These retirements are reflected in the following charts and tables.

D.1.1 Outyear 4 (PY 2029-2030) Projected Installed Capacity

PY 2029-2030 ICAP MW, Summer												
Resource Type	**LRZ1**	**LRZ2**	**LRZ3**	**LRZ4**	**LRZ5**	**LRZ6**	**LRZ7**	**LRZ8**	**LRZ9**	**LRZ10**	**Firm Externals**	**MISO**
Thermal	13,752	12,734	7,823	7,674	7,667	10,162	17,486	8,028	18,780	5,153	961	110,219
ROR/Biomass	269	197	18	0	126	190	90	32	228	0	166	1,316
Wind	7,517	997	13,842	3,513	942	1,350	3,886	180	0	185	0	32,412
Solar	2,287	4,981	3,368	6,079	2,443	7,057	5,698	4,027	5,602	1,397	0	42,940
Battery Storage	236	526	755	866	495	1,049	2,358	161	145	0	0	6,590
BTMG	1,468	365	617	316	95	348	1,157	17	14	81	0	4,478
Demand Response	1,939	736	512	425	280	1,611	1,120	1,148	348	45	0	8,162
Total	**27,467**	**20,536**	**26,934**	**18,873**	**12,048**	**21,767**	**31,795**	**13,593**	**25,117**	**6,860**	**1,126**	**206,117**

Table D-1: Summer Total Installed Capacity by Resource Type and Local Resource Zone

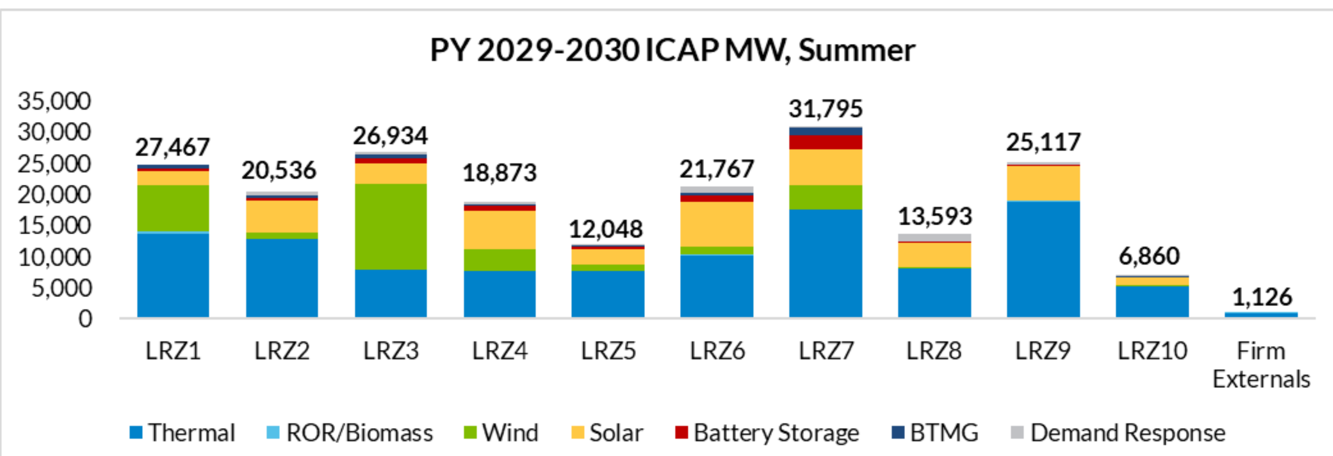


Figure D-1: Summer Total Installed Capacity by Resource Type and Local Resource Zone

PY 2029-2030 ICAP MW, Fall												
Resource Type	**LRZ1**	**LRZ2**	**LRZ3**	**LRZ4**	**LRZ5**	**LRZ6**	**LRZ7**	**LRZ8**	**LRZ9**	**LRZ10**	**Firm Externals**	**MISO**
Thermal	13,441	13,057	7,923	7,784	7,865	10,197	17,872	8,213	19,276	5,331	953	111,913
ROR/Biomass	253	189	5	0	127	175	93	23	132	0	151	1,147
Wind	7,536	1,096	14,042	3,513	1,322	1,350	3,886	180	0	185	0	33,110
Solar	2,512	5,130	3,368	6,065	2,443	7,057	5,698	4,027	5,602	1,397	0	43,300
Battery Storage	236	526	755	866	495	1,049	2,358	161	145	0	0	6,590
BTMG	1,225	356	608	312	95	195	1,068	13	19	82	0	3,973
Demand Response	1,458	710	417	385	214	1,378	676	1,059	346	5	0	6,649
Total	**26,662**	**21,064**	**27,118**	**18,925**	**12,562**	**21,402**	**31,651**	**13,676**	**25,520**	**7,000**	**1,104**	**206,682**

Table D-2: Fall Total Installed Capacity by Resource Type and Local Resource Zone

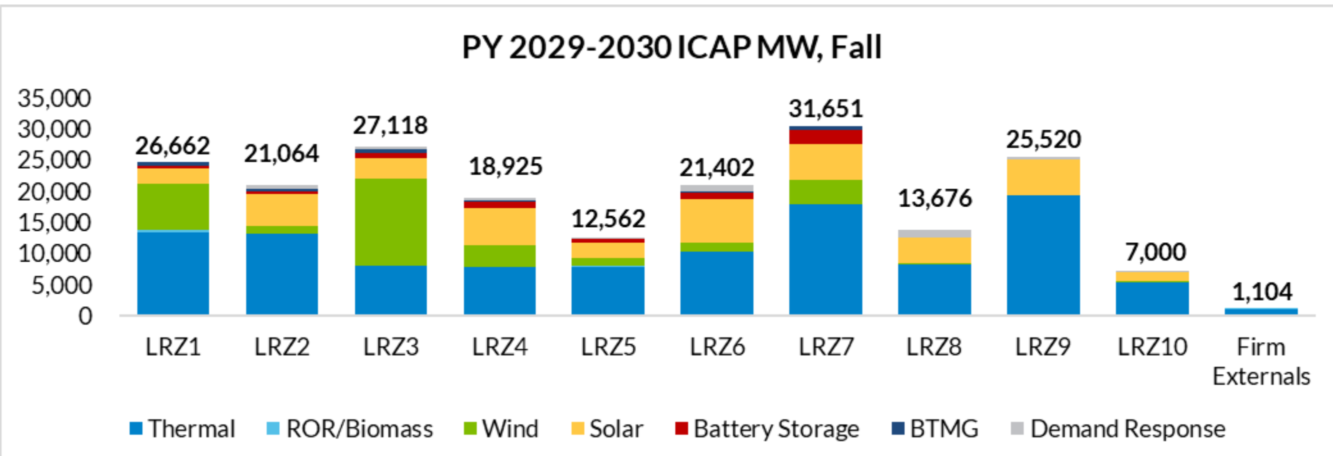


Figure D-2: Fall Total Installed Capacity by Resource Type and Local Resource Zone

PY 2029-2030 ICAP MW, Winter												
Resource Type	**LRZ1**	**LRZ2**	**LRZ3**	**LRZ4**	**LRZ5**	**LRZ6**	**LRZ7**	**LRZ8**	**LRZ9**	**LRZ10**	**Firm Externals**	**MISO**
Thermal	13,509	12,291	8,200	8,193	8,166	11,430	18,193	8,755	20,938	5,555	1,221	116,451
ROR/Biomass	261	197	5	0	125	159	98	45	201	0	149	1,240
Wind	7,536	1,096	14,042	3,513	1,322	1,350	4,084	180	0	185	0	33,308
Solar	2,463	5,112	3,368	5,956	2,254	7,057	5,698	4,027	5,602	1,397	0	42,934
Battery Storage	311	526	755	866	495	1,049	2,358	161	145	0	0	6,665
BTMG	717	333	586	321	91	333	1,014	17	9	82	0	3,503
Demand Response	1,734	677	425	329	144	1,466	582	1,091	346	5	0	6,798
Total	**26,530**	**20,232**	**27,380**	**19,178**	**12,597**	**22,843**	**32,027**	**14,276**	**27,241**	**7,224**	**1,370**	**210,899**

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

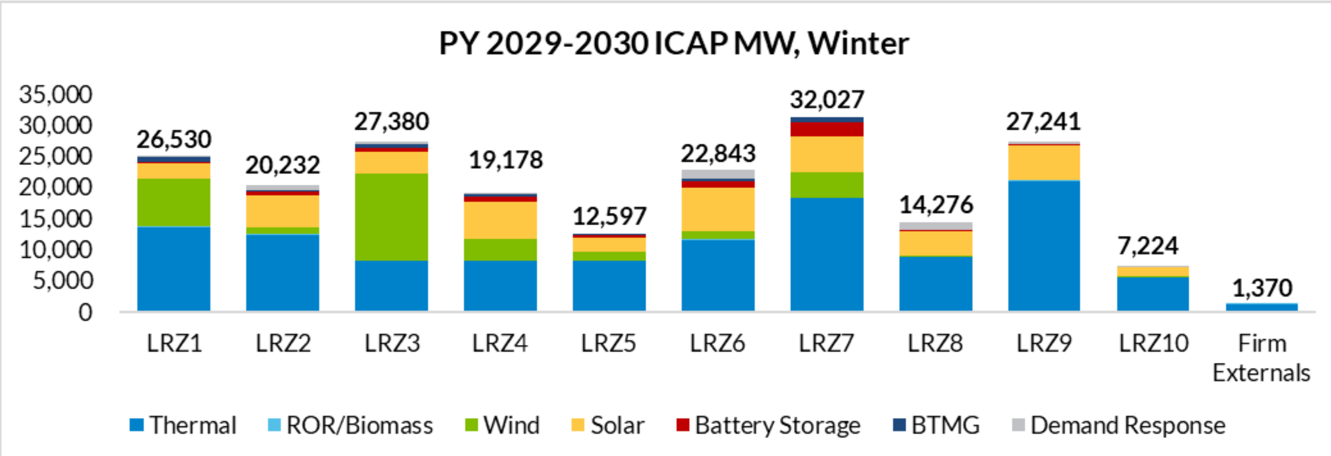


Figure D-3: Winter Total Installed Capacity by Resource Type and Local Resource Zone

PY 2029-2030 ICAP MW, Spring												
Resource Type	**LRZ1**	**LRZ2**	**LRZ3**	**LRZ4**	**LRZ5**	**LRZ6**	**LRZ7**	**LRZ8**	**LRZ9**	**LRZ10**	**Firm Externals**	**MISO**
Thermal	12,086	11,901	8,046	7,948	7,328	11,298	16,663	8,339	20,161	5,258	946	109,974
ROR/Biomass	294	212	35	0	108	134	99	37	246	0	143	1,308
Wind	7,536	1,096	14,042	3,513	1,322	1,350	4,084	180	0	185	0	33,308
Solar	2,510	5,340	3,803	6,065	2,443	7,057	5,698	4,027	5,602	1,397	0	43,943
Battery Storage	311	526	755	870	495	1,049	2,358	161	145	0	0	6,669
BTMG	1,373	412	599	313	95	348	1,138	26	21	82	0	4,405
Demand Response	1,468	705	403	385	186	1,487	619	1,104	347	5	0	6,708
Total	**25,579**	**20,191**	**27,682**	**19,095**	**11,977**	**22,722**	**30,659**	**13,874**	**26,521**	**6,927**	**1,089**	**206,315**

Table D-4: Spring Total Installed Capacity by Resource Type and Local Resource Zone

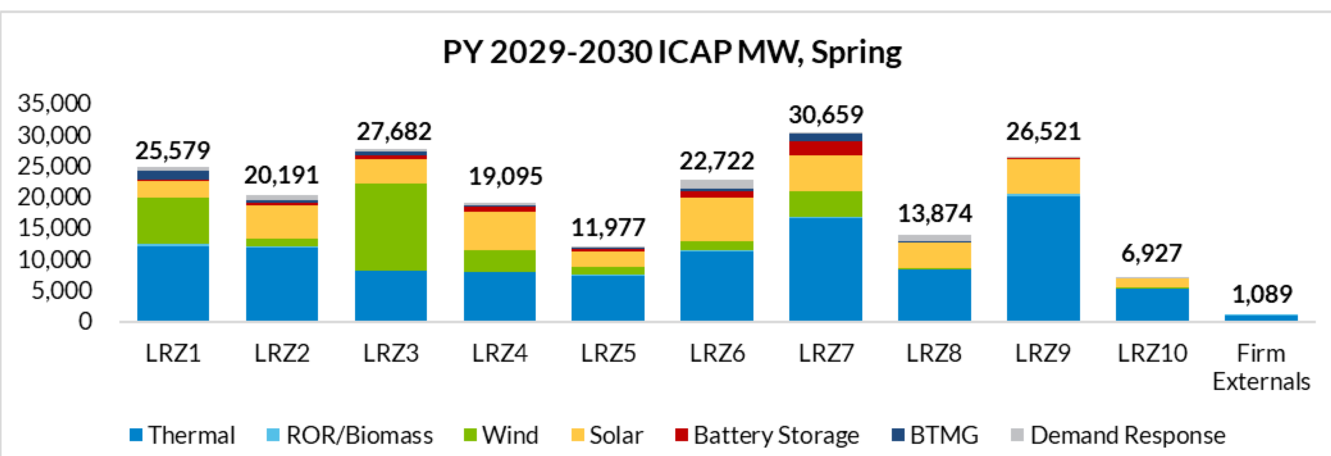


Figure D-4: Spring Total Installed Capacity by Resource Type and Local Resource Zone

D.1.2 Outyear 6 (PY 2031-2032) Projected Installed Capacity

PY 2031-2032 ICAP MW, Summer												
Resource Type	**LRZ1**	**LRZ2**	**LRZ3**	**LRZ4**	**LRZ5**	**LRZ6**	**LRZ7**	**LRZ8**	**LRZ9**	**LRZ10**	**Firm Externals**	**MISO**
Thermal	11,681	11,278	7,647	7,259	7,667	9,772	16,328	6,382	18,780	5,153	961	102,907
ROR/Biomass	269	197	13	0	126	187	57	32	101	0	166	1,148
Wind	7,330	1,642	14,032	3,513	1,322	1,300	4,084	180	0	185	0	33,588
Solar	2,512	5,490	3,803	6,095	2,443	7,057	5,698	4,327	5,602	1,397	0	44,425
Battery Storage	311	616	755	870	495	1,334	2,358	161	145	0	0	7,044
BTMG	1,450	283	617	314	95	348	1,151	17	14	81	0	4,370
Demand Response	1,939	736	512	425	280	1,611	1,120	1,148	348	45	0	8,162
Total	**25,492**	**20,242**	**27,379**	**18,476**	**12,428**	**21,609**	**30,796**	**12,247**	**24,989**	**6,860**	**1,126**	**201,644**

Table D-5: Summer Total Installed Capacity by Resource Type and Local Resource Zone

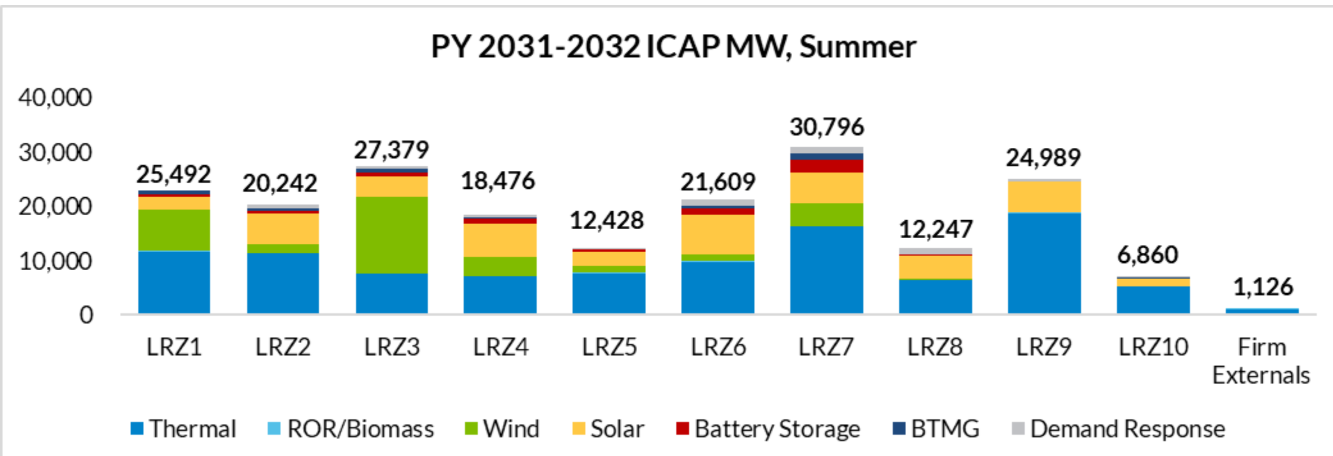


Figure D-5: Summer Total Installed Capacity by Resource Type and Local Resource Zone

PY 2031-2032 ICAP MW, Fall												
Resource Type	**LRZ1**	**LRZ2**	**LRZ3**	**LRZ4**	**LRZ5**	**LRZ6**	**LRZ7**	**LRZ8**	**LRZ9**	**LRZ10**	**Firm Externals**	**MISO**
Thermal	11,909	11,608	7,741	7,345	7,865	9,794	16,695	6,549	19,276	5,331	953	105,066
ROR/Biomass	253	189	0	0	127	172	60	23	66	0	151	1,041
Wind	7,419	1,642	14,032	3,513	1,322	1,300	4,084	180	0	185	0	33,677
Solar	2,512	5,490	3,803	6,065	2,443	7,057	5,698	4,327	5,602	1,397	0	44,395
Battery Storage	311	616	755	870	495	1,334	2,358	161	145	0	0	7,044
BTMG	1,212	266	608	310	95	195	1,062	13	19	82	0	3,862
Demand Response	1,458	710	417	385	214	1,378	676	1,059	346	5	0	6,649
Total	**25,074**	**20,521**	**27,356**	**18,489**	**12,562**	**21,230**	**30,633**	**12,312**	**25,455**	**7,000**	**1,104**	**201,735**

Table D-6: Fall Total Installed Capacity by Resource Type and Local Resource Zone

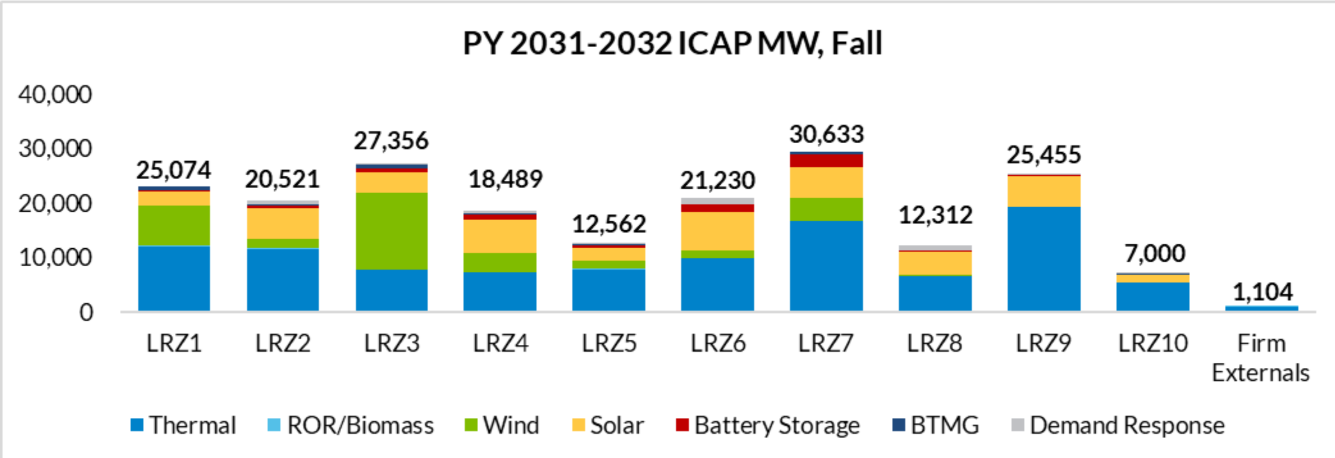


Figure D-6: Fall Total Installed Capacity by Resource Type and Local Resource Zone

PY 2031-2032 ICAP MW, Winter												
Resource Type	**LRZ1**	**LRZ2**	**LRZ3**	**LRZ4**	**LRZ5**	**LRZ6**	**LRZ7**	**LRZ8**	**LRZ9**	**LRZ10**	**Firm Externals**	**MISO**
Thermal	12,333	11,961	8,006	7,701	8,166	11,020	16,990	7,077	20,938	5,555	1,221	110,968
ROR/Biomass	261	197	0	0	125	156	65	45	84	0	149	1,082
Wind	7,419	1,642	14,032	3,513	1,322	1,300	4,084	180	0	185	0	33,677
Solar	2,463	5,472	3,803	5,956	2,254	7,057	5,698	4,327	5,602	1,397	0	44,029
Battery Storage	311	616	755	866	495	1,334	2,358	161	145	0	0	7,040
BTMG	710	222	586	319	91	333	1,007	17	9	82	0	3,376
Demand Response	1,734	677	425	329	144	1,466	582	1,091	346	5	0	6,798
Total	**25,232**	**20,786**	**27,606**	**18,685**	**12,597**	**22,665**	**30,784**	**12,898**	**27,124**	**7,224**	**1,370**	**206,971**

Table D-7: Winter Total Installed Capacity by Resource Type and Local Resource Zone

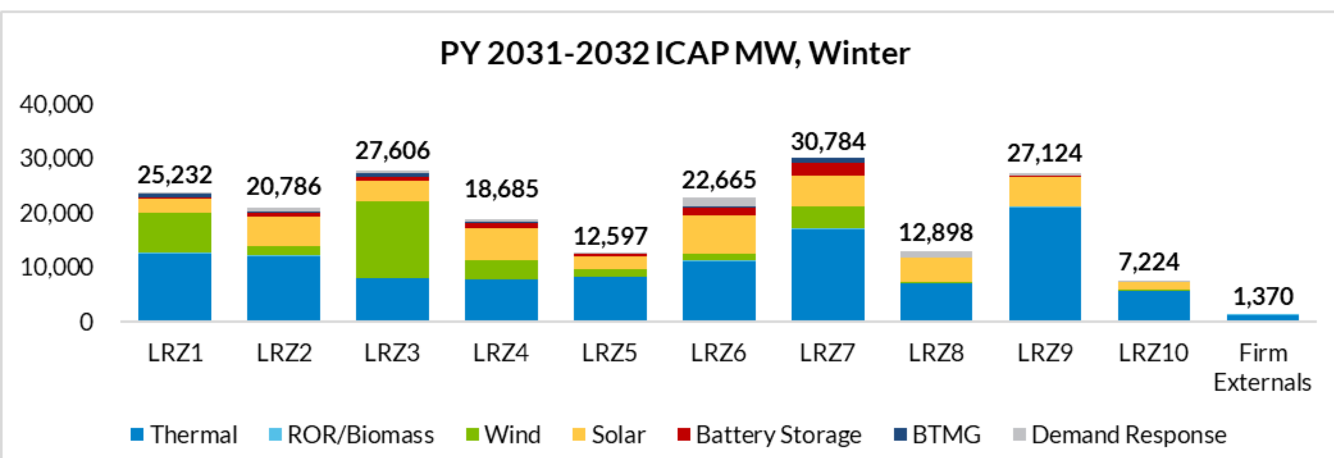


Figure D-7: Winter Total Installed Capacity by Resource Type and Local Resource Zone

PY 2031-2032 ICAP MW, Spring												
Resource Type	**LRZ1**	**LRZ2**	**LRZ3**	**LRZ4**	**LRZ5**	**LRZ6**	**LRZ7**	**LRZ8**	**LRZ9**	**LRZ10**	**Firm Externals**	**MISO**
Thermal	11,587	11,579	7,860	7,507	7,328	10,451	15,498	6,671	20,161	5,258	946	104,845
ROR/Biomass	294	212	31	0	108	131	66	37	104	0	143	1,126
Wind	7,419	1,642	14,032	3,513	1,322	1,300	4,084	180	0	185	0	33,677
Solar	2,510	5,490	3,803	6,065	2,443	7,057	5,698	4,327	5,602	1,397	0	44,393
Battery Storage	311	616	755	870	495	1,334	2,358	161	145	0	0	7,044
BTMG	1,357	291	599	310	95	348	1,131	26	21	82	0	4,260
Demand Response	1,468	705	403	385	186	1,487	619	1,104	347	5	0	6,708
Total	**24,947**	**20,534**	**27,481**	**18,651**	**11,977**	**22,107**	**29,454**	**12,506**	**26,379**	**6,927**	**1,089**	**202,053**

Table D-8: Spring Total Installed Capacity by Resource Type and Local Resource Zone

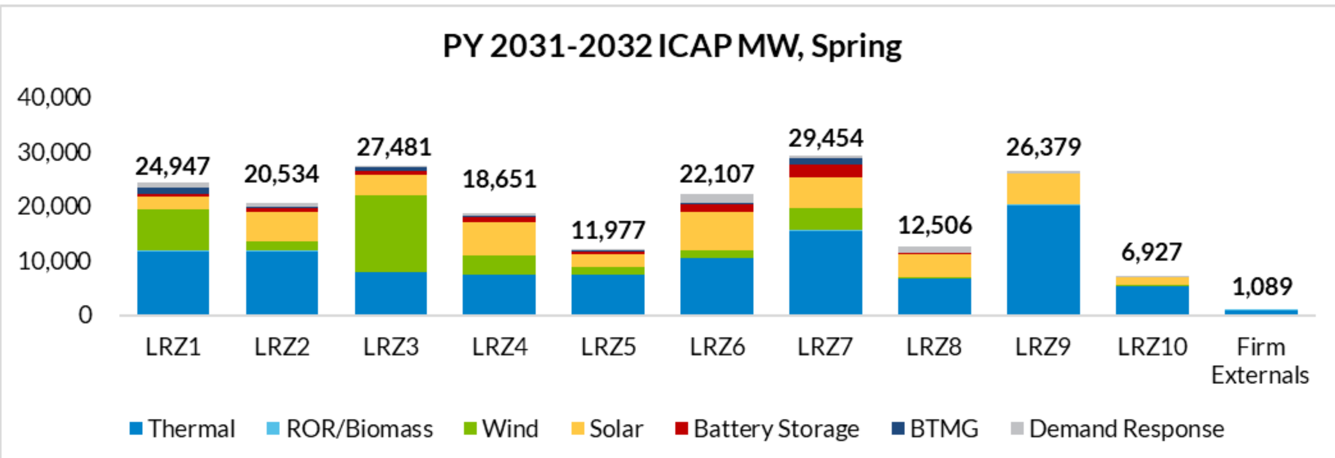


Figure D-8: Spring Total Installed Capacity by Resource Type and Local Resource Zone

Appendix E: MISO System ICAP PRM Results

For Planning Year 2026-2027, the ratio of MISO capacity to forecasted MISO system peak demand yielded a Planning Reserve Margin ICAP of 15 percent for the Summer season. Numerous values and calculations went into determining the MISO system PRM ICAP (Table E-1).

MISO ICAP Planning Reserve Margin (PRM)	PY 2026-2027 Summer	PY 2026-2027 Fall	PY 2026-2027 Winter	PY 2026-2027 Spring	Formula Key
MISO System Peak Demand (MW)	125,531	111,042	106,248	101,854	**[A]**
Installed Capacity (ICAP) (MW)	144,628	142,060	151,169	145,306	**[B]**
Thermal	114,388	116,031	121,679	114,821	[B.1]
Run of River/Biomass	1,220	1,066	1,160	1,235	[B.2]
Wind	5,207	6,610	8,863	5,542	[B.3]
Solar	5,584	2,685	2,628	4,213	[B.4]
Battery Storage	706	706	702	706	[B.5]
Demand Response	8,162	6,649	6,798	6,708	[B.6]
BTMG	4,506	4,003	3,525	4,431	[B.7]
New Thermal	3,220	3,240	3,585	4,400	[B.8]
New Wind and Solar	1,633	1,069	2,228	3,250	[B.9]
Firm External Support ICAP (MW)	1,133	1,111	1,377	1,096	**[C]**
Adjustment to ICAP (MW)	(1,440)	(7,550)	(1,440)	(1,820)	**[D]**
ICAP PRM Requirement (PRMR) (MW)	144,322	135,621	151,106	144,582	**[E]** = [B]+[C]+[D]
MISO PRM ICAP	**15.0%**	**22.1%**	**42.2%**	**42.0%**	**[F]** = [E]-[A]/[A]

Table E-1: Planning Year 2026-2027 MISO System ICAP Planning Reserve Margin