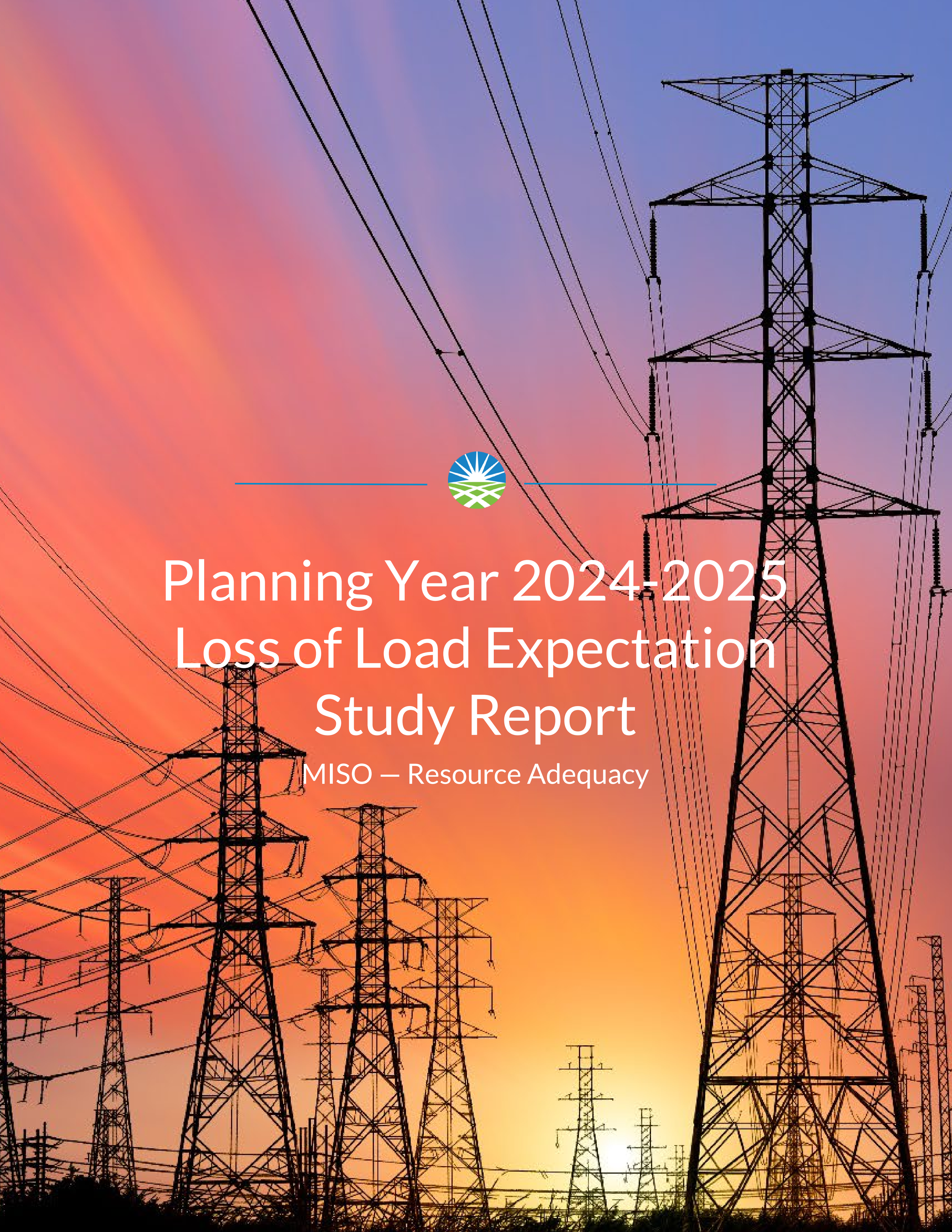


Planning Year 2024-2025 Loss of Load Expectation Study Report

MISO — Resource Adequacy

Contents

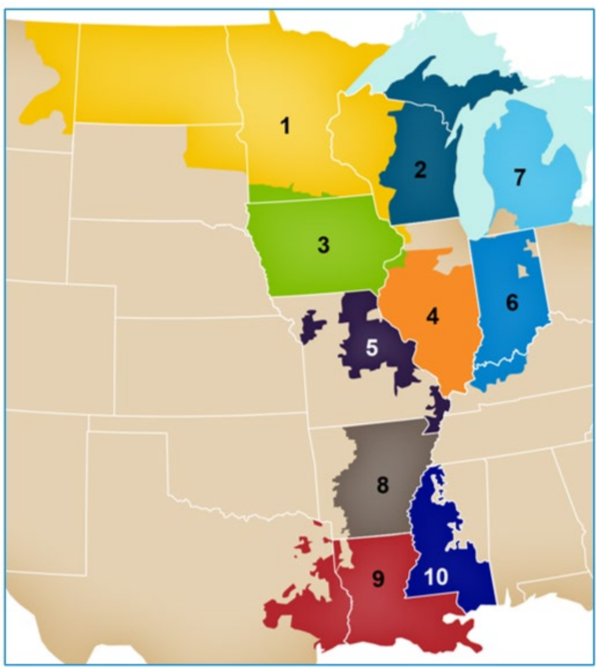
Executive Summary

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

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

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

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



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

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

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

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

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

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

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

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

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

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

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

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

1 LOLE Study Process Overview

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

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

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

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

Table 1-1: Example Local Clearing Requirement Calculation

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

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

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

1.1 Study Improvements

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

PY 2024-2025 study included the following improvements:

- **Enhanced modeling of battery storage resources:** Previously, battery storage was modeled as a must-run resource that is always available at nameplate capacity, unless on a forced outage (assumed to be a rate of 5% for every season). Now, battery storage is modeled as use-limited with a duration of 4 hours.
- **Realistic commercial operation dates for future resources**: PY 2024-2025 study considered more realistic anticipated commercial operation dates (CODs) for future resource additions with executed generation interconnection agreements (GIAs), factoring in macroeconomic and regulatory realities. Interconnection customers have indicated to MISO that factors such as supply-chain issues, regulatory approvals, contractor availability, and other economic factors such as PPAs, are requiring GIA projects to delay commercial operations. Correspondingly, declared anticipated CODs were adjusted based on GIA projects in the queue per customer feedback.
- **Improved cold-weather related outages**: Accounting of additional forced outages during extreme cold temperatures in the Winter season was updated in the PRM and LRR calculations. For context, the LOLE model has historically utilized a 5-year average EFORd based on historic GADS data. These resource-specific forced outage rates were annualized under the prior annual construct and were seasonalized in last year's LOLE Study, which better captured the seasonal availability of resources as observed in operations.

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

  What has changed for this year's study was the reduction of the available Winter unforced capacity in the PRM and LRR calculations as a result of these cold weather outages. A comparative probabilistic analysis with and without the cold weather outage adder was performed to quantify the impact of modeling the cold weather outage adder profiles on the system-wide requirements. This impact was distributed pro-rata to the zonal level based on the average magnitude of the zonal cold weather outage adder profiles used in the LRR calculations.

2 Transfer Analysis

2.1 Calculation Methodology and Process Description

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

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

2.1.1 Generation Pools

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

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

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

2.1.2 Redispatch

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

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

2.1.3 Sensitivity

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

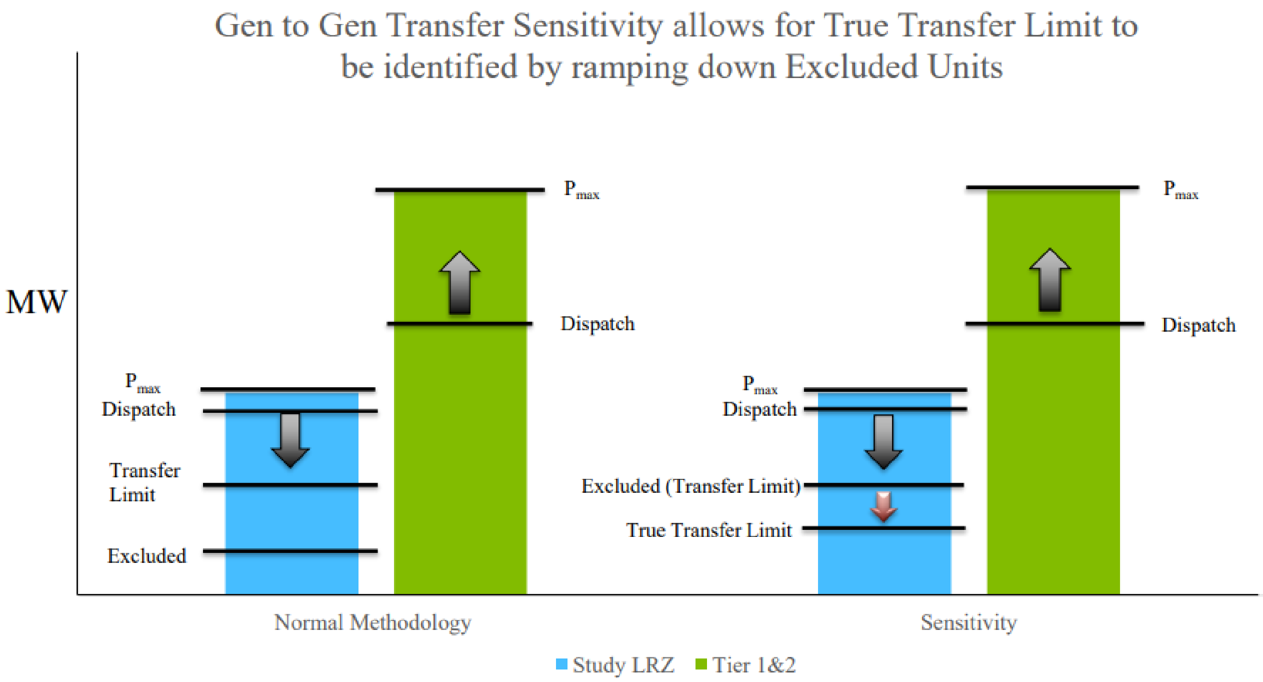


Figure 2-1: Generation-to-Generation Transfer Sensitivity

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

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

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

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

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

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

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

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

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

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

2.2 Powerflow Models and Assumptions

2.2.1 Tools Used

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

2.2.2 Inputs Required

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

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

2.2.3 Powerflow Modeling

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

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

Table 2-1: Model Assumptions

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

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

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

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

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

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

2.2.4 General Assumptions

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

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

Equation 2-1: Total Transfer Capability

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

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

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

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

Table 2-2: Example Subsystem

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

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

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

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

2.3 Results for CIL/CEL and ZIA/ZEA

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

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

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

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

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

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

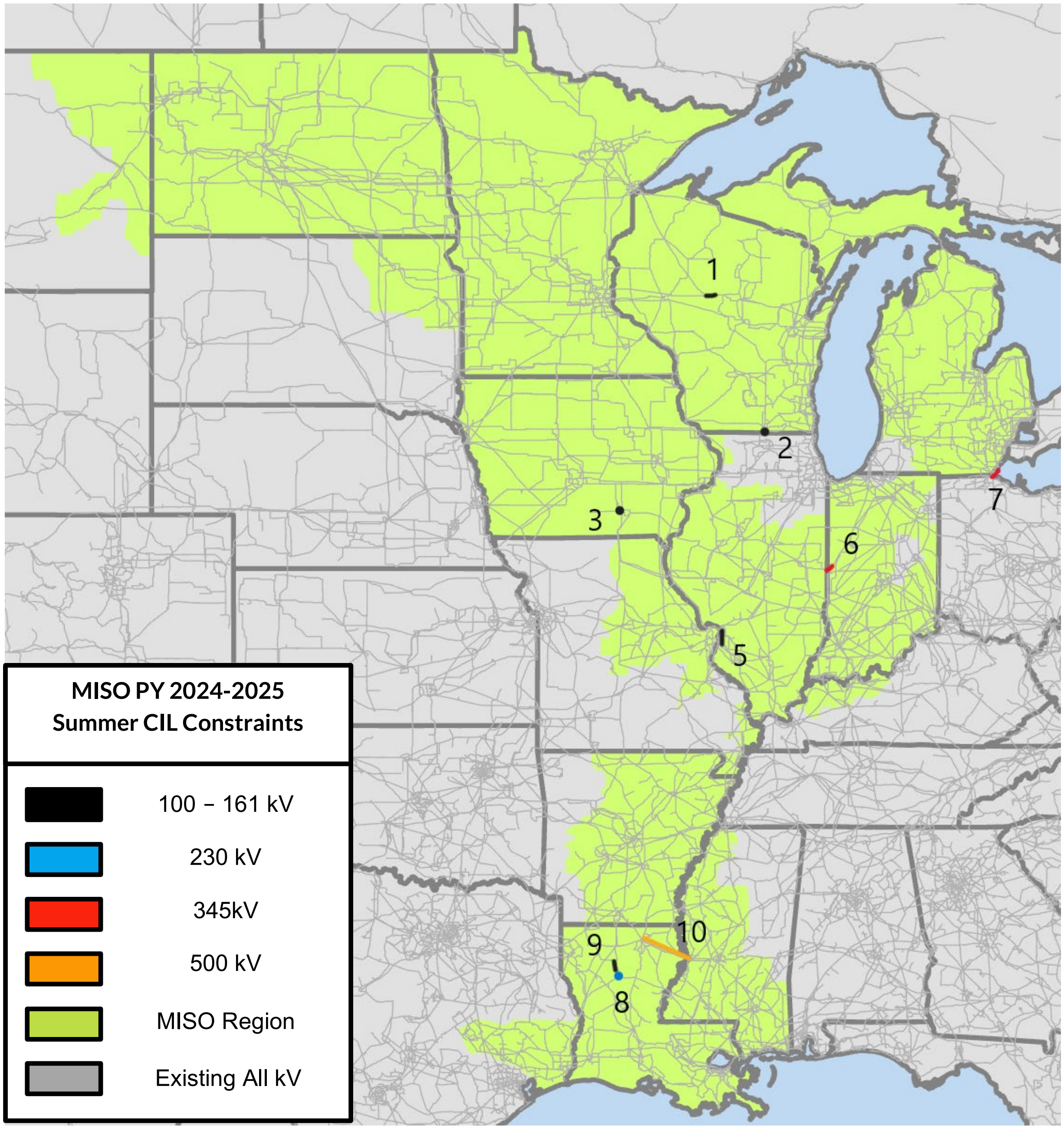


Figure 2-2: Planning Year 2024-2025 Summer Capacity Import Constraints Map

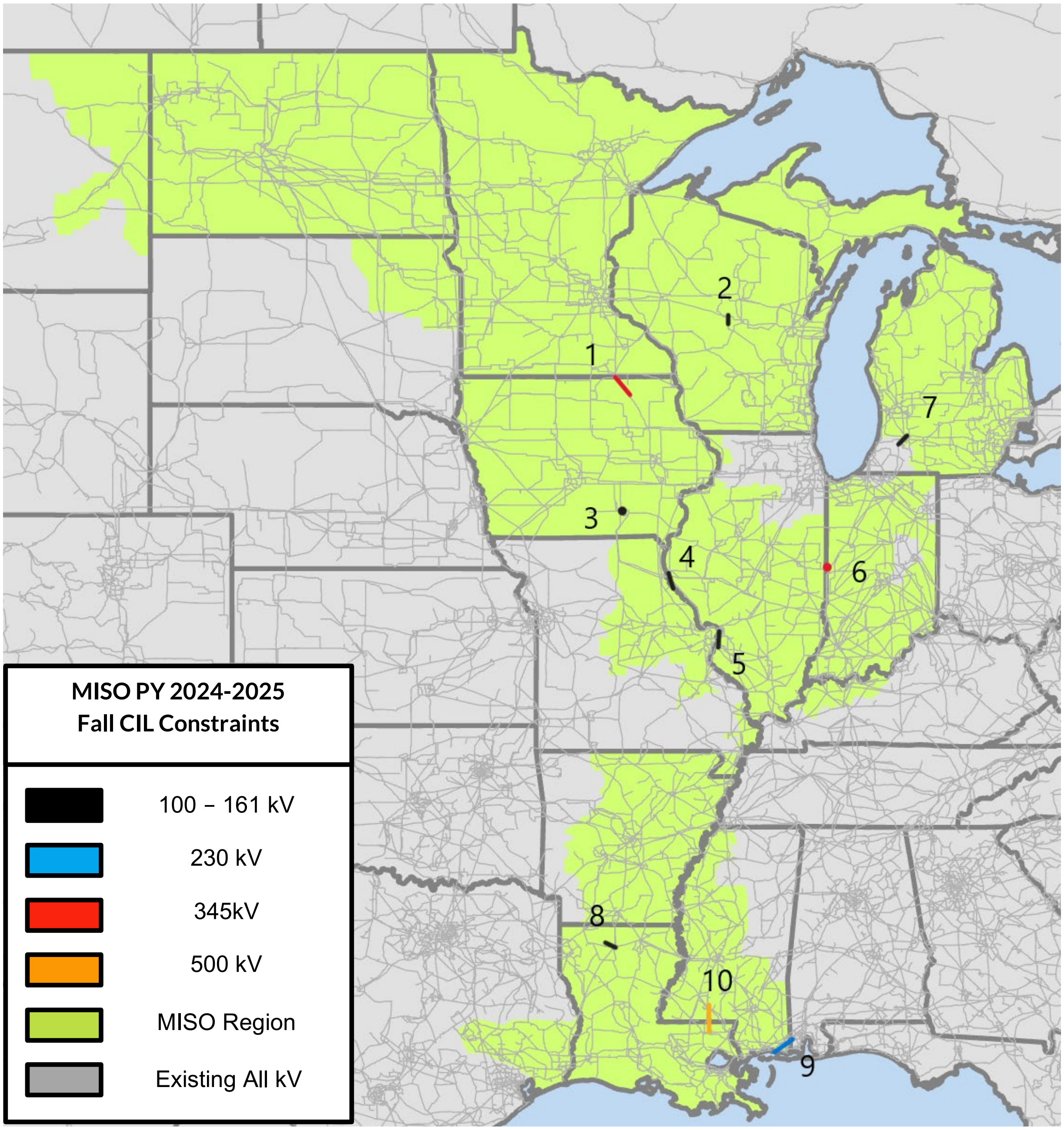


Figure 2-3: Planning Year 2024-2025 Fall Capacity Import Constraints Map

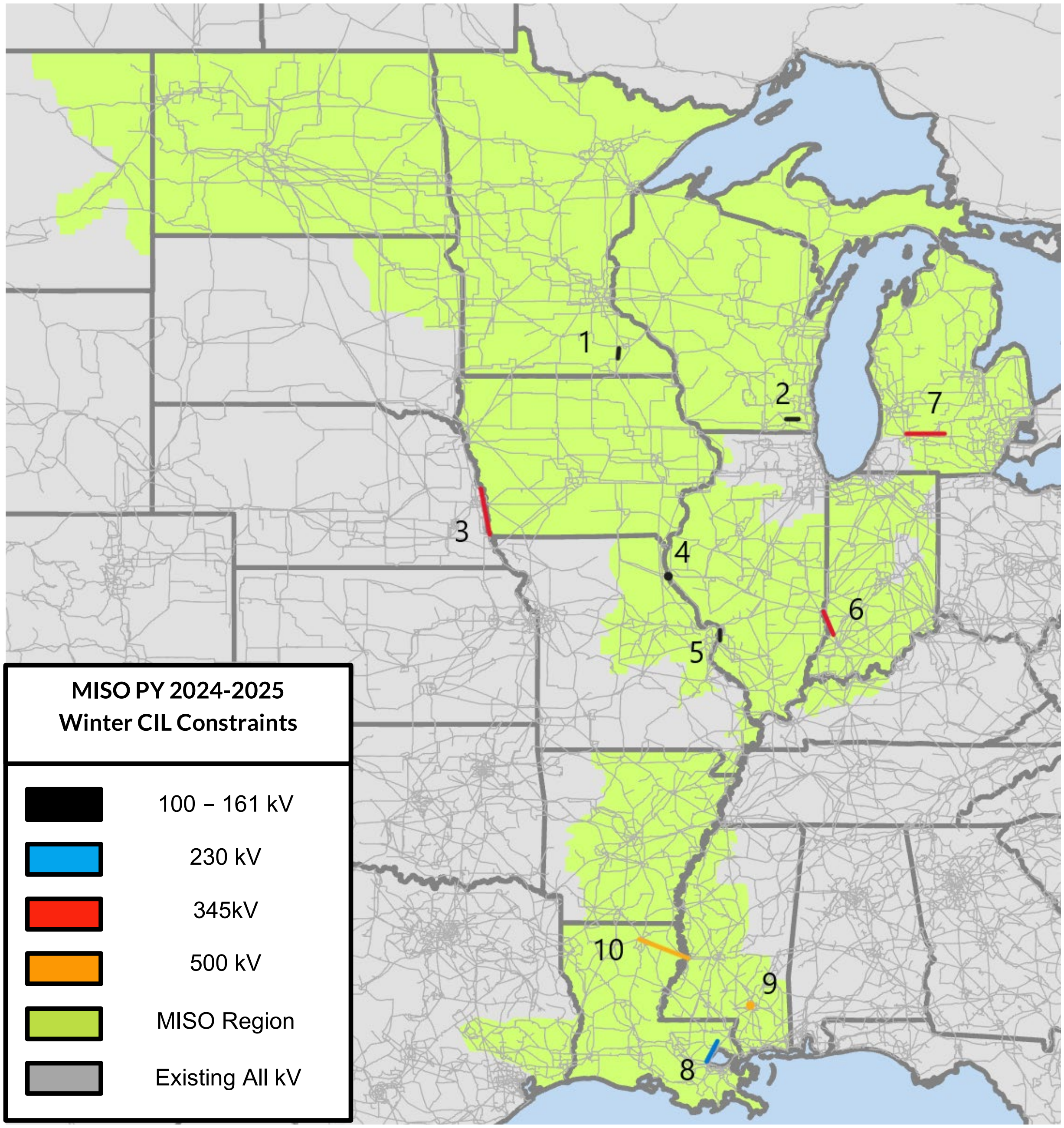


Figure 2-4: Planning Year 2024-2025 Winter Capacity Import Constraints Map

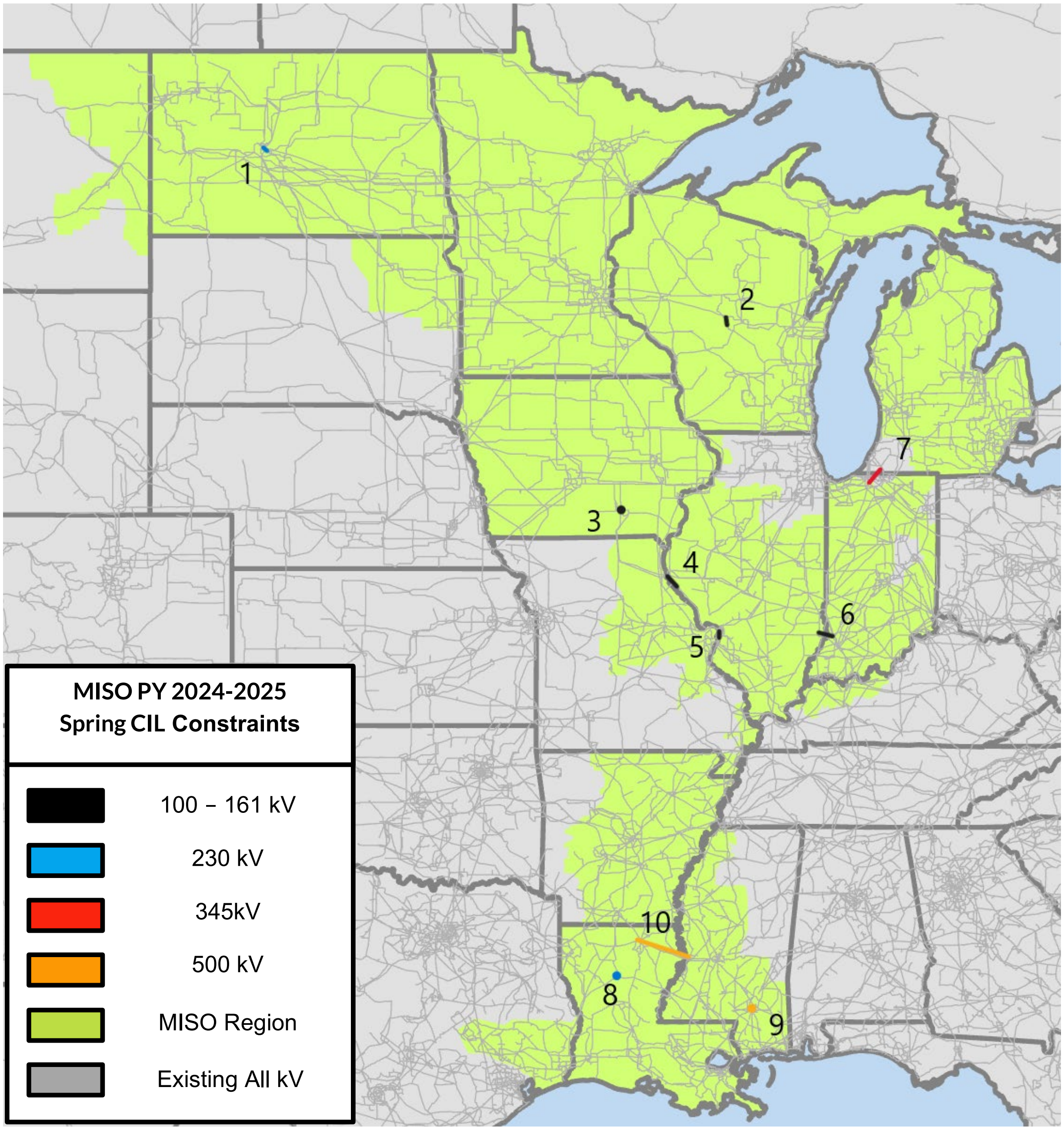


Figure 2-5: Planning Year 2024-2025 Spring Capacity Import Constraints Map

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

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

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

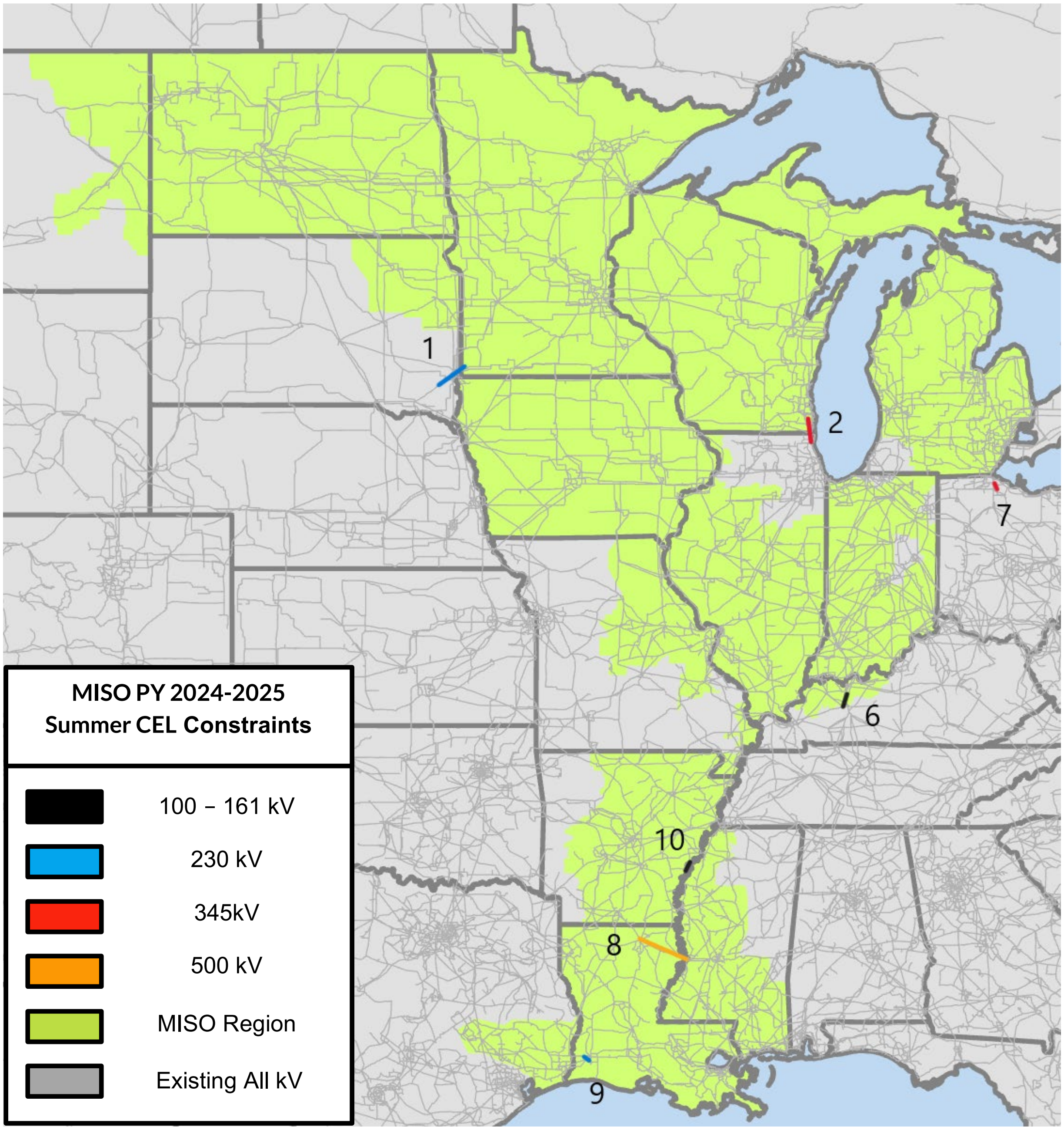


Figure 2-6: Planning Year 2024-2025 Summer Export Constraint Map

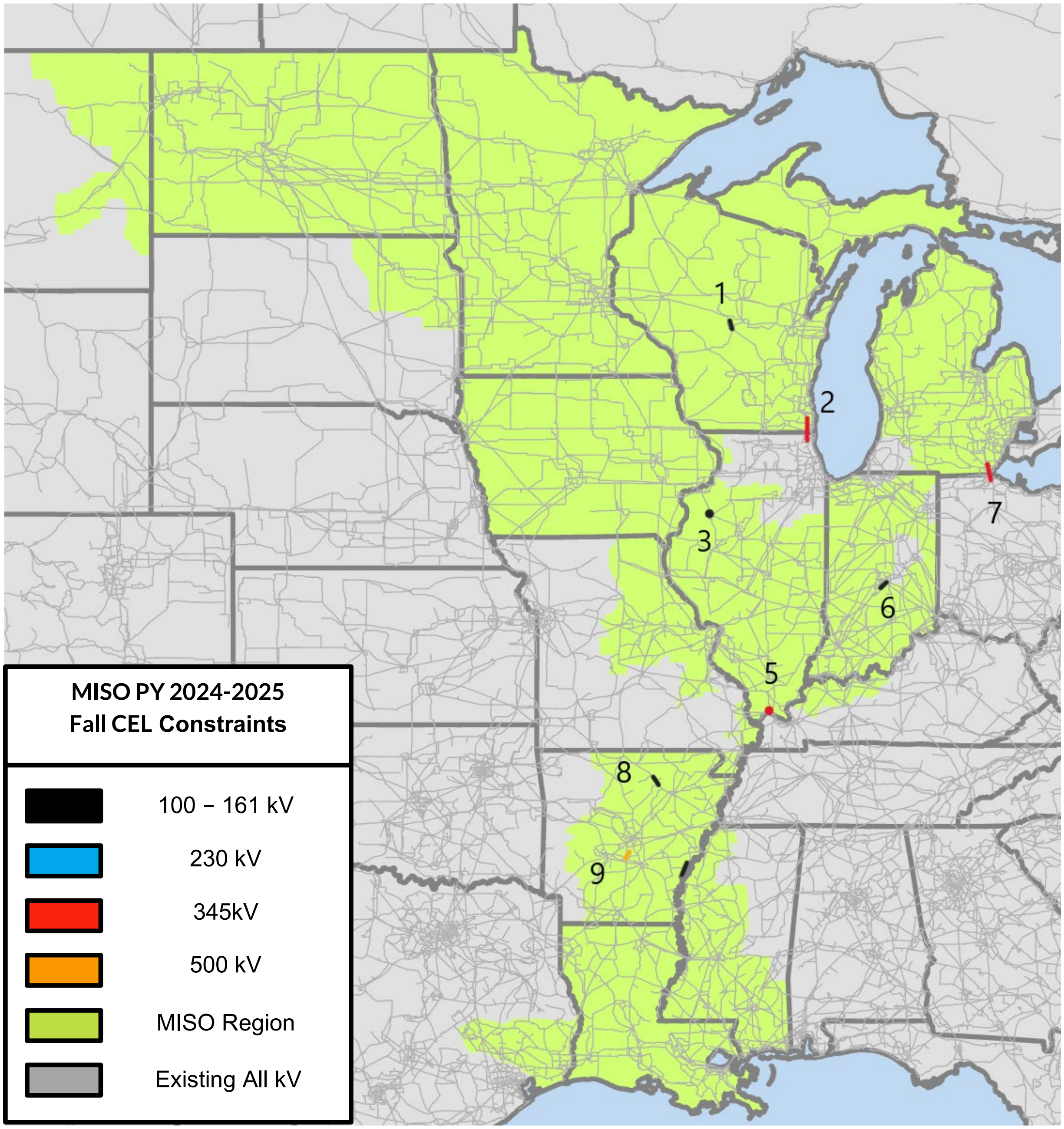


Figure 2-7: Planning Year 2024-2025 Fall Export Constraint Map

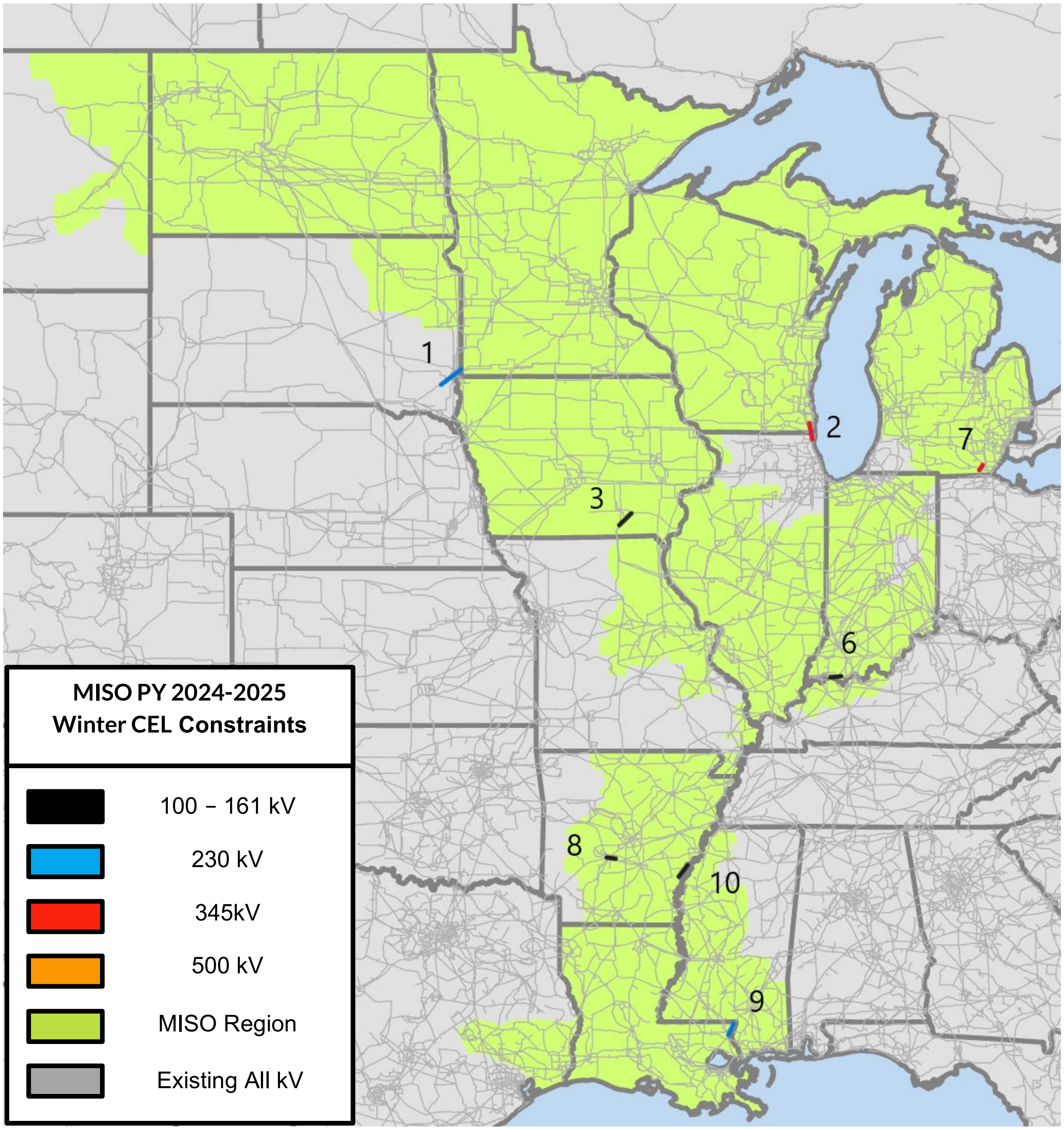


Figure 2-8: Planning Year 2024-2025 Winter Export Constraint Map

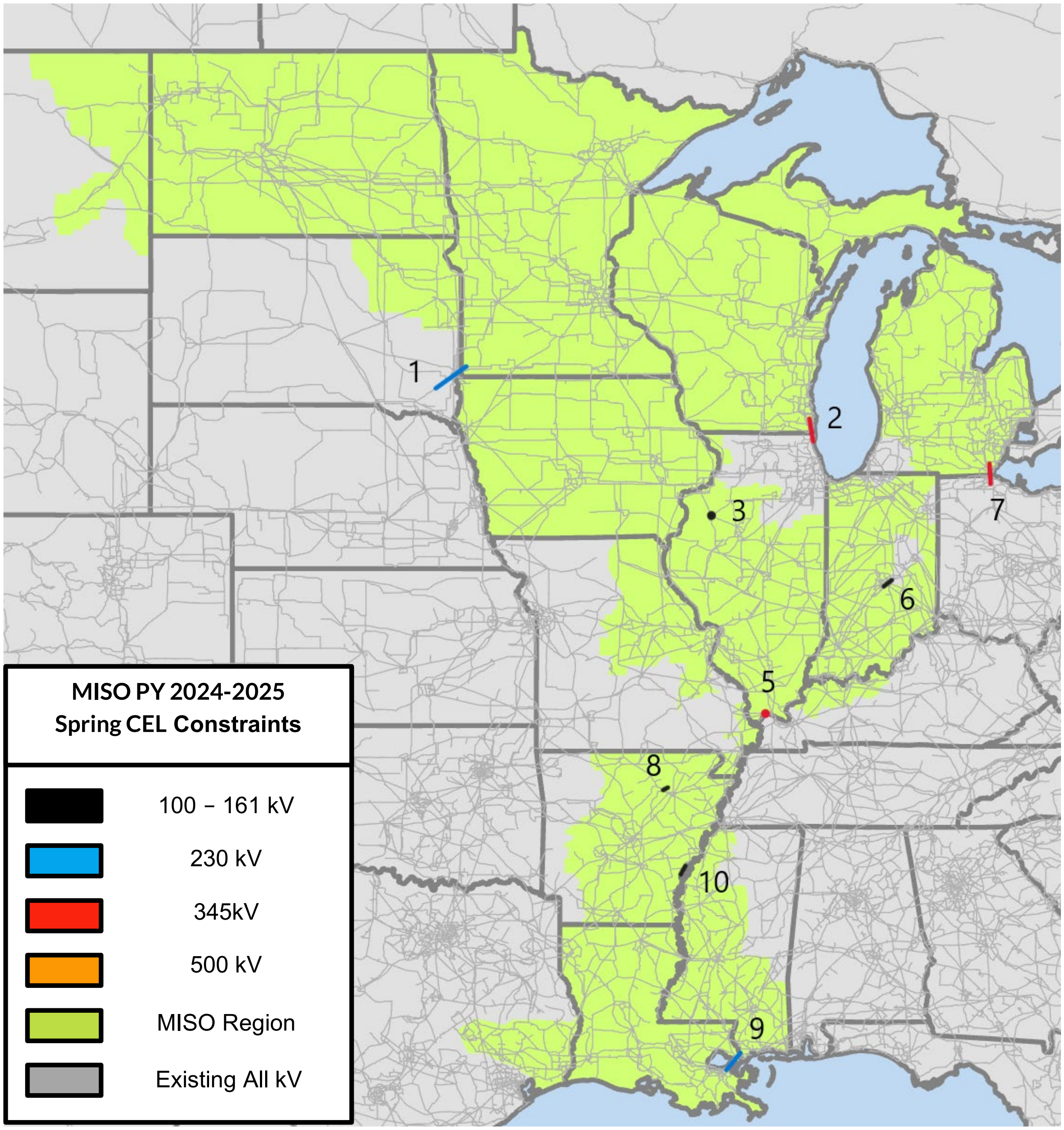


Figure 2-9: Planning Year 2024-2025 Spring Export Constraint Map

3 Loss of Load Expectation Analysis

3.1 LOLE Modeling Input Data and Assumptions

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

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

3.2 MISO Generation

3.2.1 Thermal Units

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

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

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

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

Pooled EFORd GADS Years	**2018-2022 (%)**	**2017-2021 (%)**	**2016-2020 (%)**	**2015-2019 (%)**	**2014-2018 (%)**	**2013-2017 (%)**
LOLE Study Planning Year	**PY 2024-2025 LOLE Study** Summer	**PY 2023-2024 LOLE Study** Summer	**PY 2022-2023 LOLE Study** Annualized	**PY 2021-2022 LOLE Study** Annualized	**PY 2020-2021 LOLE Study** Annualized	**PY 2019-2020 LOLE Study** Annualized
Combined Cycle	5.92	5.54	5.85	5.52	5.70	5.37
Combustion Turbine (0-20 MW)	24.42	23.40	35.20	36.38	40.39	23.18
Combustion Turbine (20-50 MW)	6.54	6.30	13.65	14.20	15.29	15.76
Combustion Turbine (50+ MW)	4.88	4.07	4.36	4.76	4.65	5.18
Diesel Engines	17.14	12.79	7.25	10.05	23.53	10.26
Fluidized Bed Combustion	*	*	*	*	*	*
Hydro (0-30 MW)	*	*	*	*	*	*
Hydro (30+ MW)	*	*	*	*	*	*
Nuclear	*	*	*	*	*	*
Pumped Storage	*	*	*	*	*	*
Steam – Coal (0-100 MW)	*	*	*	*	5.33	4.60
Steam - Coal (100-200 MW)	*	*	*	*	*	*
Steam - Coal (200-400 MW)	*	*	*	10.47	10.16	9.82
Steam - Coal (400-600 MW)	*	*	*	*	*	*
Steam - Coal (600-800 MW)	*	*	*	*	*	8.22
Steam - Coal (800-1000 MW)	*	*	*	*	*	*
Steam - Gas	14.04	11.26	11.84	12.91	12.54	11.56

Pooled EFORd GADS Years	2018-2022 (%)	2017-2021 (%)	2016-2020 (%)	2015-2019 (%)	2014-2018 (%)	2013-2017 (%)
LOLE Study Planning Year	**PY 2024-2025 LOLE Study** Summer	**PY 2023-2024 LOLE Study** Summer	**PY 2022-2023 LOLE Study** Annualized	**PY 2021-2022 LOLE Study** Annualized	**PY 2020-2021 LOLE Study** Annualized	**PY 2019-2020 LOLE Study** Annualized
Steam - Oil	*	*	*	*	*	*
Steam - Waste Heat	*	*	*	*	*	*
Steam - Wood	*	*	*	*	*	*
MISO Weighted System-wide	8.24	8.23	9.04	9.36	9.24	9.28

**MISO weighted system-wide forced outage rate used in place of class data for classes with less than 30 resources reporting 12 or more months of data*

Table 3-1: Historical Class Average Forced Outage Rates

Pooled EFORd GADS Years	2018-2022 (%)	2018-2022 (%)	2018-2022 (%)	2018-2022 (%)
LOLE Study Planning Year 2024-2025	**Summer 2024**	**Fall 2024**	**Winter 2024-2025**	**Spring 2025**
Combined Cycle	5.92	7.43	5.38	6.55
Combustion Turbine (0-20 MW)	24.42	24.17	46.17	51.36
Combustion Turbine (20-50 MW)	6.54	18.59	50.59	34.26
Combustion Turbine (50+ MW)	4.88	7.23	10.53	5.15
Diesel Engines	17.14	14.26	24.94	8.89
Fluidized Bed Combustion	*	*	*	*
Hydro (0-30 MW)	*	*	*	*
Hydro (30+ MW)	*	*	*	*
Nuclear	*	*	*	*

Pooled EFORd GADS Years	2018-2022 (%)	2018-2022 (%)	2018-2022 (%)	2018-2022 (%)
LOLE Study Planning Year 2024-2025	**Summer 2024**	**Fall 2024**	**Winter 2024-2025**	**Spring 2025**
Pumped Storage	*	*	*	*
Steam – Coal (0-100 MW)	*	*	*	*
Steam - Coal (100-200 MW)	*	*	*	*
Steam - Coal (200-400 MW)	*	*	*	*
Steam - Coal (400-600 MW)	*	*	*	*
Steam - Coal (600-800 MW)	*	*	*	*
Steam - Coal (800-1000 MW)	*	*	*	*
Steam - Gas	14.04	13.26	11.11	12.07
Steam - Oil	*	*	*	*
Steam - Waste Heat	*	*	*	*
Steam - Wood	*	*	*	*
MISO Weighted System-wide	8.24	9.15	11.23	10.33

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

**MISO weighted system-wide forced outage rate used in place of class data for classes with less than 30 resources reporting 12 or more months of data*

3.2.2 Behind-the-Meter Generation

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

3.2.3 Attachment Y

MISO obtained information on generating resources with approved suspensions or retirements (as of June 1, 2023) through MISO's Attachment Y process. Any resource with an approved retirement or suspension in Planning Year

2024-2025 was excluded from the year-one analysis during the months the resource has been approved to be out of service for. This same methodology is used for the four- and six-year analyses.

3.2.4 Future Generation

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

3.2.5 Intermittent Resources

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

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

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

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

3.2.6 Demand Response

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

3.3 MISO Load Data

The Planning Year 2024-2025 LOLE analysis used a load training process with neural net software to establish a correlated relationship in the trained and predicted load shapes between historical weather and load data. This relationship was then applied to 30 years of hourly historical load data to create 30 different load shapes for each LRZ to capture both load diversity and seasonal variations. The Zonal Coincident Peak Forecasts provided by the Load

Serving Entities were used to develop zonal- and monthly-specific load forecast scaling factors which scale the average of the 30 load shapes based on provided forecasts. The results of this process are shown as the MISO System Peak Demand (Table 4-1) and LRZ Peak Demands (Table 5-1, Table 5-2, Table 5-3, & Table5-4).

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

3.3.1 Weather Uncertainty

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

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

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

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

In the fourth step of the process and after the neural net has finished, we check the results of the neural net at extreme temperatures to smooth out any over- or under-predicted loads by comparing against the entire 30 years of historical correlated load and weather years. MISO looks for hours where the load is plus or minus 30% different than the previous hour and corrects those hours.

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

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

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

3.3.2 Economic Load Uncertainty

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

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

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

Table 3-3: Economic Uncertainty

3.4 External System

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

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

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

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

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

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

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

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

3.5 Loss of Load Expectation Analysis and Metric Calculations

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

3.5.1 Seasonal LOLE Distribution

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

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

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

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

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

3.5.2 MISO-Wide LOLE Analysis and PRM Calculation

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

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

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

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

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

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

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

3.5.3 LRZ LOLE Analysis and Local Reliability Requirement Calculation

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

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

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

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

4 MISO System Planning Reserve Margin

4.1 Planning Year 2024-2025 MISO Planning Reserve Margin Results

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

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

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

4.1.1 Additional Risk Metric Statistics

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

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

Table 4-2: Additional Risk Metric Statistics

4.2 Comparison of PRM Targets Across 10 Years

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

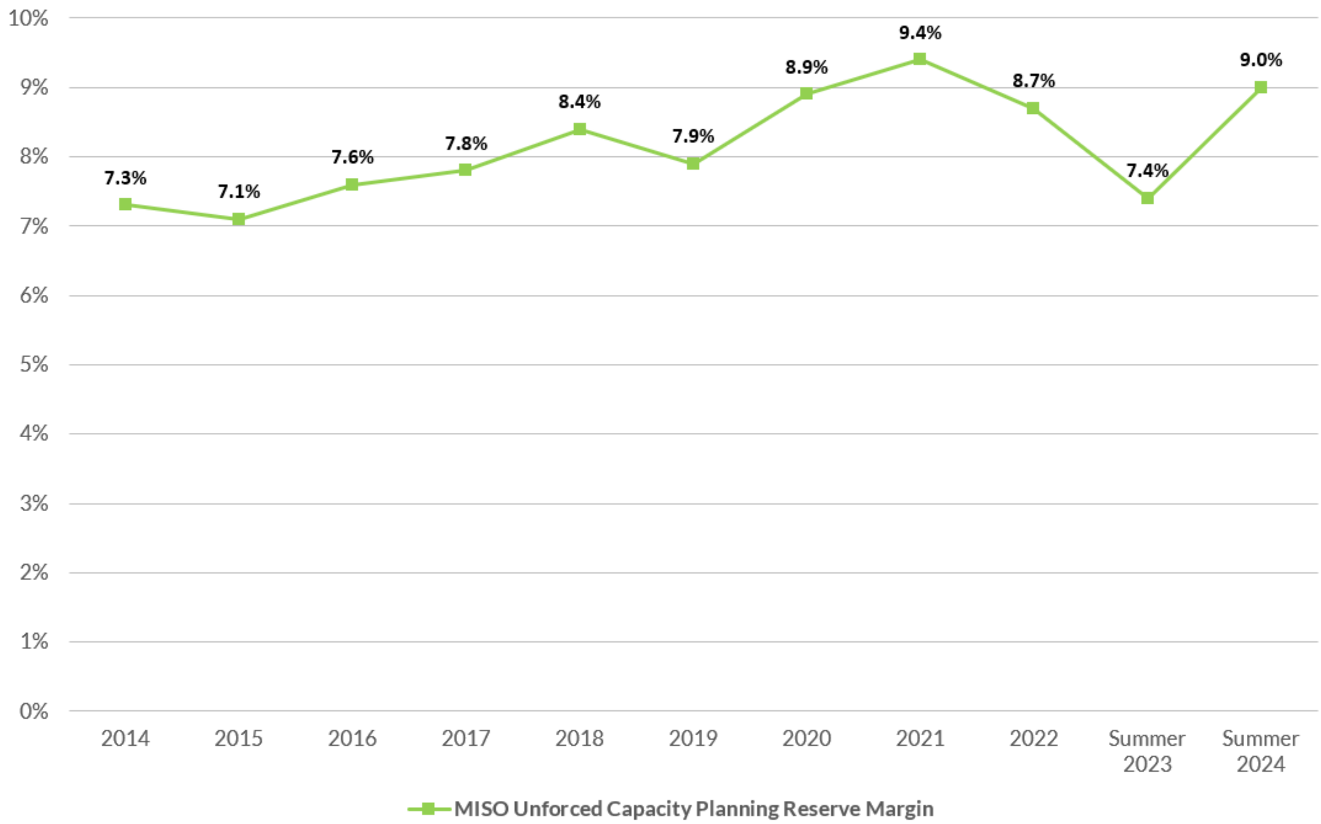


Figure 4-1: Comparison of PRM Targets Across 10 Years

4.3 Future Years 2023 through 2032 Planning Reserve Margins

Beyond the Planning Year 2024-2025 LOLE Study analysis, LOLE analysis will be performed for the four-year-out Planning Year of 2027-2028, as well as for the six-year-out Planning Year of 2029-2030. All other future Planning Years in scope will be derived from interpolation and extrapolation of the three modeled Planning Years.

5 Local Resource Zone Analysis – LRR Results

5.1 Planning Year 2024-2025 Local Resource Zone Analysis

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

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

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

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

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

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

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

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

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

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

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

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

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

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

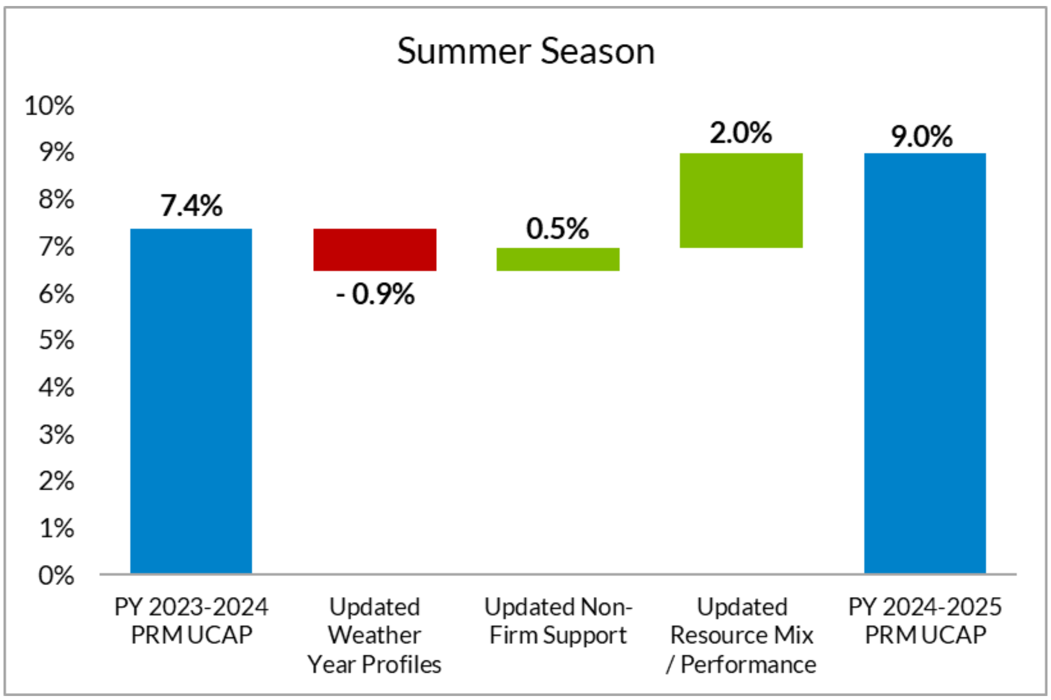


Figure A-1: Waterfall Chart of Summer PRM UCAP from PY 2023-2024 to PY 2024-2025

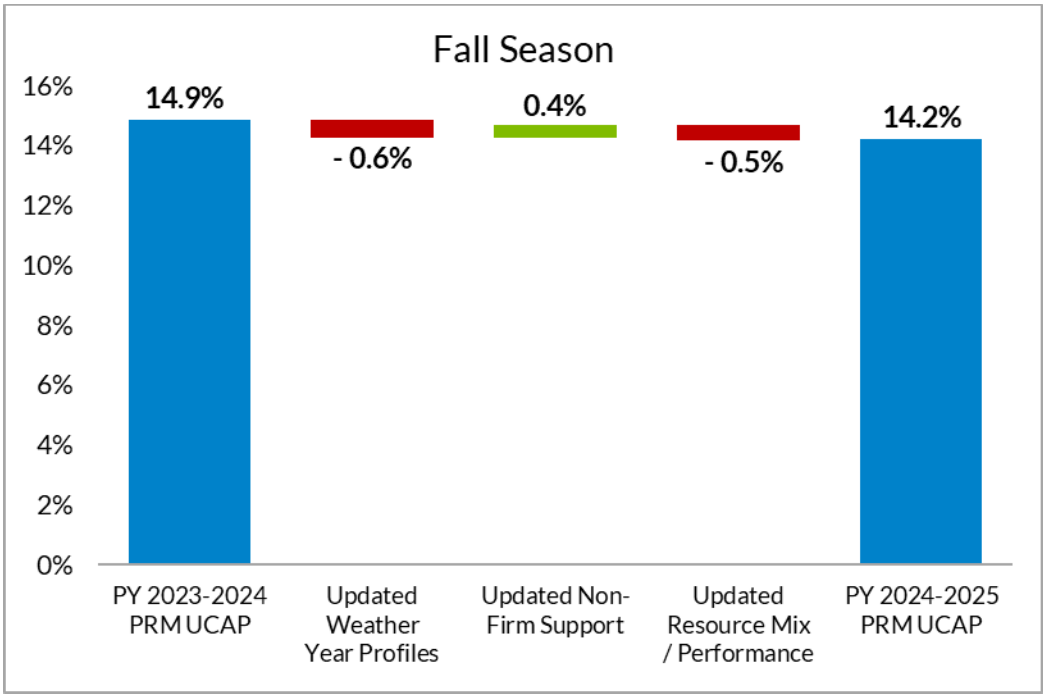


Figure A-2: Waterfall Chart of Fall PRM UCAP from PY 2023-2024 to PY 2024-2025

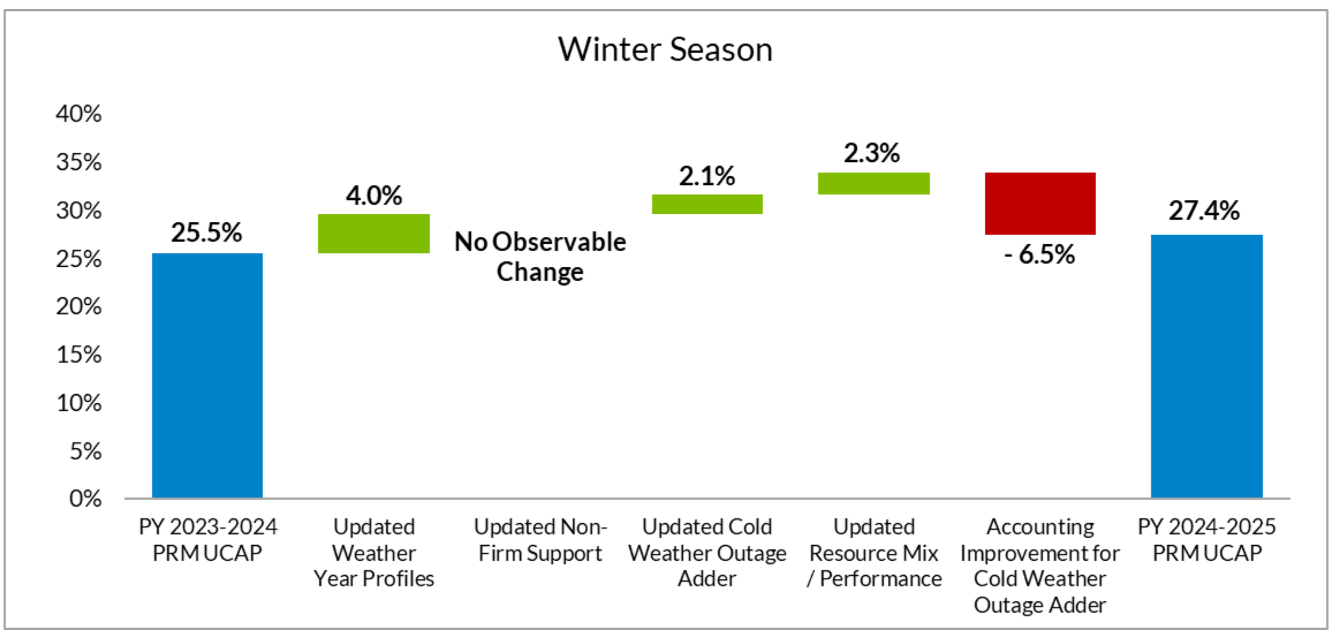


Figure A-3: Waterfall Chart of Winter PRM UCAP from PY 2023-2024 to PY 2024-2025

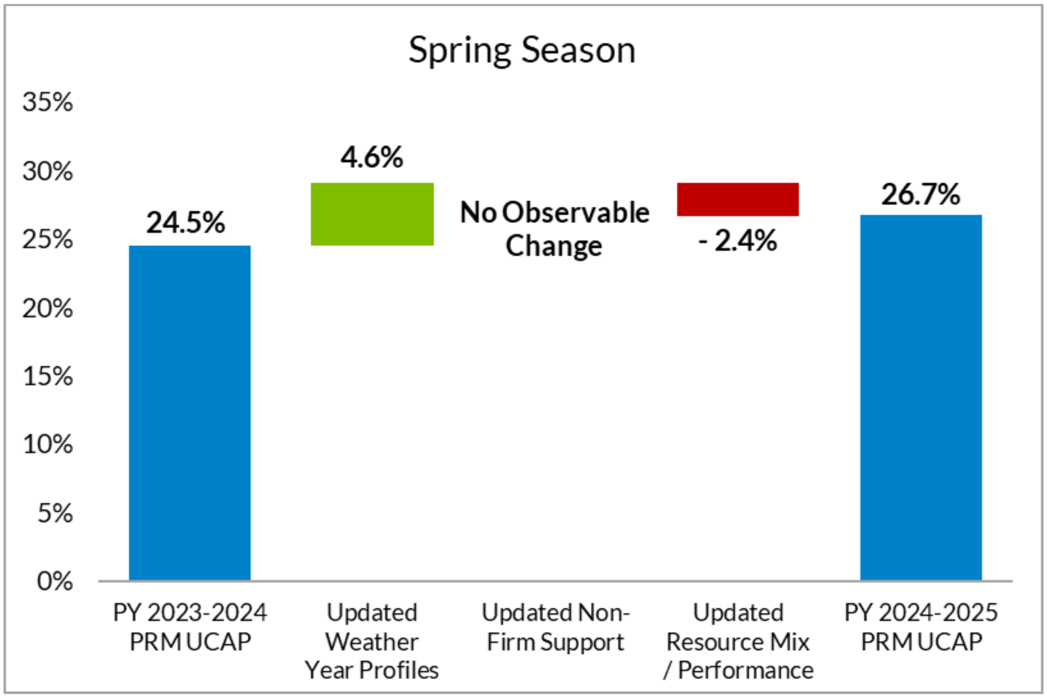


Figure A-4: Waterfall Chart of Spring PRM UCAP from PY 2023-2024 to PY 2024-2025

6.1 Waterfall Chart Details

6.1.1 Updated Weather Year Profiles

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

6.1.2 Updated Non-Firm Support

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

6.1.3 Updated Resource Mix / Performance

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

6.1.4 Updated Cold Weather Outage Adder (Winter only)

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

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

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

7 Appendix B: Increased Winter Thermal Capability Sensitivity

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

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

MISO Local Resource Zone 1

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

MISO Local Resource Zone 2

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

MISO Local Resource Zone 3

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

MISO Local Resource Zone 4

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

MISO Local Resource Zone 5

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

MISO Local Resource Zone 6

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

MISO Local Resource Zone 7

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

MISO Local Resource Zone 8

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

MISO Local Resource Zone 9

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

MISO Local Resource Zone 10

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

9 Appendix D: Compliance Conformance Table

Requirements under: Standard BAL-502-RF-03	Response
R1 The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall:	The Planning Year 2024-2025 LOLE Study Report is the annual Resource Adequacy Analysis for the peak season of June 2024 through May 2025 and beyond. Analysis of Planning Year 2024-2025 is in Sections 0 and 0. Analysis of Future Years 2025-2034 will be included in Appendix F as an addendum to the study report in early 2024.
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 year" criterion).	Section 0 of this report outlines the utilization of LOLE in the reserve margin determination. "These metrics were derived through probabilistic modeling of the system, first solving to the industry standard annual LOLE risk target of 1 day in 10 years, or 0.1 day per year, and then solving to the minimum seasonal LOLE criteria of 0.01 LOLE for seasons demonstrating minimal risk."
R1.1.1 The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the loss of Load probability.	Section 3.3 of this report. "Direct Control Load Management and Interruptible Demand types of demand response were explicitly included in the LOLE model as resources. Demand response is dispatched in the LOLE model to avoid load shed during simulation when all other available generation has been exhausted."
R1.1.2 The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median forecast peak Net Internal Demand (planning reserve margin).	Section 4.1 of this report. "…the ratio of MISO capacity to forecasted MISO system peak demand yielded a planning ICAP reserve margin…"
R1.2 Be performed or verified separately for each of the following planning years.	Covered in the segmented R1.2 responses below.
R1.2.1 Perform an analysis for Year One.	In Sections 0 and 0, a full analysis was performed for Planning Year 2024-2025.
R1.2.2 Perform an analysis or verification at a minimum for one year in the 2 through 5 year period and at a minimum one year in the 6 though 10 year period.	Analysis of Planning Years 2027-2028 and 2029-2030 will be included in Appendix F as an addendum to the study report in early 2024.

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 0.1 of this report: "The sixth and final step of the load training process is to average the monthly peak loads of the predicted load shapes and adjust them to match each LRZ's monthly Zonal Coincident Peak Forecast provided by the Load Serving Entities for each of the study years." Load Forecast Uncertainty – A detailed explanation of the weather and economic uncertainties is given in Section 3.3. Load Diversity / Seasonal Load Variations — In Section 0 of this report: "MISO has adopted a six-step load training process in order to capture the weather uncertainty associated with the most recent 50/50 load forecasts submitted by the Load Serving Entities for the development of the 30 years of hourly zonal correlated load and weather shapes in the LOLE model… The third step of the process utilizes neural net software to establish functional relationships between the most recent five years of historical weather and load data." Demand Modeling Assumptions / Curtailable and Interruptible Demand — All Load Modifying Resources must first meet registration requirements through Module E. As stated in Section 3.2.6: "Each demand response program was modeled individually with a monthly capacity, limited by duration and the number of times each program can be called upon for each season."

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 0 details how historic performance data and seasonal ratings are gathered, and includes discussion of future units and the modeling assumptions for intermittent capacity resources. A more detailed explanation of firm capacity purchases and sales is in Section 3.4.
R1.3.3 Transmission limitations that prevent the delivery of generation reserves	Annual MTEP deliverability analysis identifies transmission limitations preventing delivery of generation reserves. Additionally, Section 0 of this report details the transfer analysis to capture transmission constraints limiting capacity transfers.
R1.3.3.1 Criteria for including planned Transmission Facility additions in the analysis	Inclusion of the planned transmission addition assumptions is detailed in Section 2.2.3.
R1.3.4 Assistance from other interconnected systems including multi-area assessment considering Transmission limitations into the study area.	Section 3.4 provides the analysis on the treatment of external support assistance and limitations.

Requirements under: Standard BAL-502-RF-03	Response
R1.4 Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included: • Availability and deliverability of fuel. • Common mode outages that affect resource availability. • Environmental or regulatory restrictions of resource availability. • Any other demand (Load) response programs not included in R1.3.1. • Sensitivity to resource outage rates. • Impacts of extreme weather/drought conditions that affect unit availability. • Modeling assumptions for emergency operation procedures used to make reserves available. • Market resources not committed to serving Load (uncommitted resources) within the Planning Coordinator area.	Fuel availability, environmental restrictions, common mode outage and extreme weather conditions are all part of the historical availability performance data that goes into the unit's EFORd statistic. The use of the EFORd values is covered in Section 0.1. The use of demand response programs is mentioned in Section 0.6. The effects of resource outage characteristics on the reserve margin are outlined in Section 3.7.1 by examining the difference between PRM ICAP and PRM UCAP values.
R1.5 Consider Transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included	Transmission maintenance schedules were not included in the analysis of the transmission system due to the limited availability of reliable long-term maintenance schedules and minimal impact to the results of the analysis. However, Section 0 treats worst-case theoretical outages by Perform 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 0 and 0.
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 0 and 0.
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 0 and 0, the peak load and estimated amount of resources for Planning Year 2024-2025 are shown. This includes the detail for each transmission constrained sub-area.
R2.1 This documentation shall cover each of the years in year one through ten.	Appendix F will cover the future Planning Years when the report is amended in early 2024 after the outyear analyses have been completed.

Requirements under: Standard BAL-502-RF-03	Response
R2.2 This documentation shall include the Planning Reserve margin calculated per requirement R1.1 for each of the three years in the analysis.	The prompt Planning Year seasonal PRM values are covered in Sections 4.1. The outyear Planning Years 4 (2027-2028) and 6 (2029-2030) will be covered in Appendix F when the report is amended in early 2024 after the outyear analyses have been completed.
R2.3 The documentation as specified per requirement R2.1 and R2.2 shall be publicly posted no later than 30 calendar days prior to the beginning of Year One.	The final PY 2024-2025 LOLE Study Report will be posted publicly in December 2023, several months prior to the start of the applicable Planning Year.
R3 The Planning Coordinator shall identify any gaps between the needed amount of planning reserves defined in Requirement R1, Part 1.1 and the projected planning reserves documented in Requirement R2.	In Sections 0 and 0 is shown the differences between the needed amount and the projected planning reserves for Planning Year 2024-2025. The needed amount of planning reserves for the outyear Planning Years 4 (2027-2028) and 6 (2029-2030) will be covered in Appendix F when the report is amended in early 2024 after the outyear analyses have been completed.

10 Appendix E: Acronyms List Table

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

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

11 Appendix F: Outyear PRM and LRR Results

Outyear PRM and LRR results for the future Plannings Years 2027-2028 and 2029-2030 will be published as an addendum to this report in early 2024 once the supporting probabilistic simulations and analyses have been completed.