Planning Year 2021-2022 Loss of Load Expectation Study Report

Loss of Load Expectation Working Group

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Revision History

Reason for Revision	Revised by:	Date:
Draft Posted	MISO	10/16/2020
Final Posted	MISO	10/30/2020
Fixed 2025 PRM typo in table 5.4	MISO	12/08/2020

1 Executive Summary

Midcontinent Independent System Operator (MISO) conducts an annual Loss of Load Expectation (LOLE) study to determine a Planning Reserve Margin Unforced Capacity (PRM UCAP), zonal per-unit Local Reliability Requirements (LRR), Zonal Import Ability (ZIA), Zonal Export Ability (ZEA), Capacity Import Limits (CIL) and Capacity Export Limits (CEL). The results of the study and its deliverables supply inputs to the MISO Planning Resource Auction (PRA).

The 2021-2022 Planning Year LOLE Study:

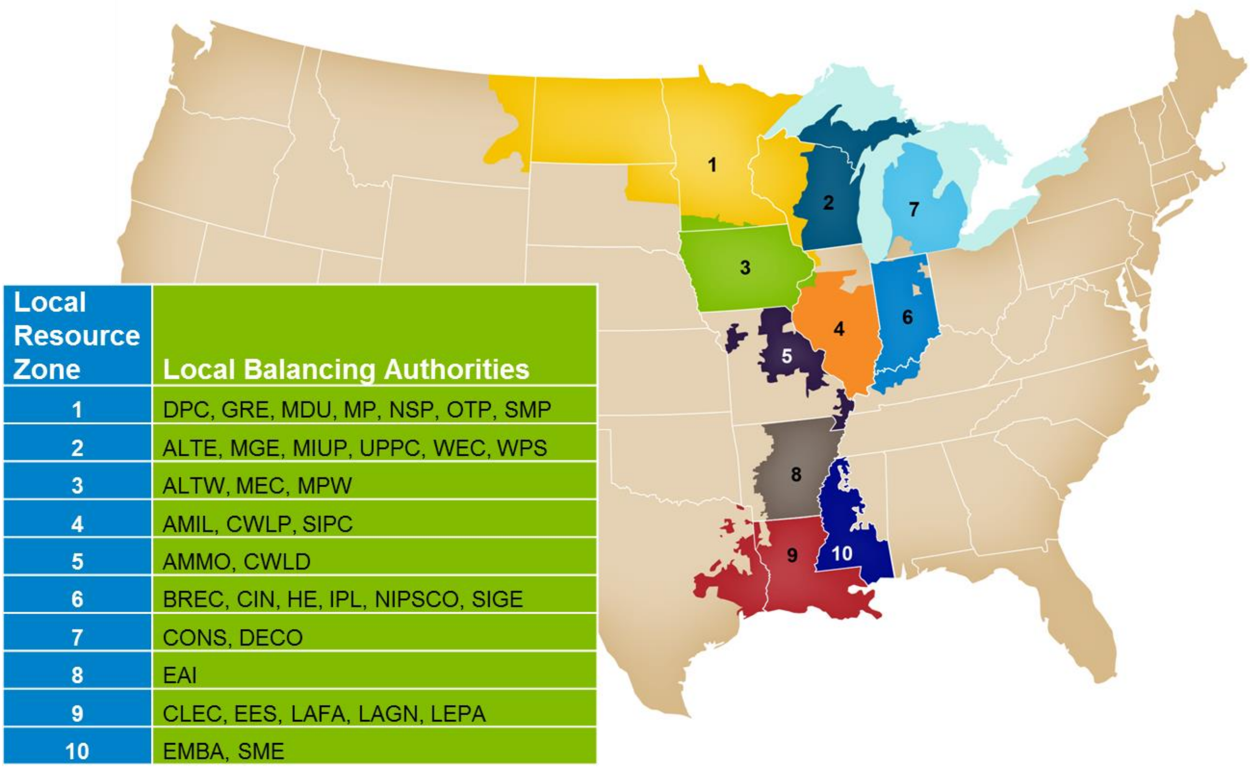
- Establishes a PRM UCAP of 9.4 percent to be applied to the Load Serving Entity (LSE) coincident peaks for the planning year starting June 2021 and ending May 2022
- Uses the Strategic Energy Risk Valuation Model (SERVM) software for Loss of Load analysis to provide results applicable across the MISO market footprint
- Provides initial zonal ZIA, ZEA, CIL and CEL for each Local Resource Zone (LRZ) (Figure 1-1). These values may be adjusted in March 2021 based on changes to MISO units with firm capacity commitments to non-MISO load, and equipment rating changes since the LOLE analysis. The Simultaneous Feasibility Test (SFT) process can further adjust CIL and CEL to assure the resources cleared in the auction are simultaneously reliable.
- Determines a minimum planning reserve margin that would result in the MISO system experiencing a less than one-day loss of load event every 10 years, as per the MISO Tariff.[1] The MISO analysis shows that the system would achieve this reliability level when the amount of installed capacity available is 1.183 times that of the MISO system coincident peak.
- Sets forth initial zonal-based (Table 1-1) PRA deliverables in the LOLE charter.

The stakeholder review process played an integral role in this study. The MISO staff would like to thank the Loss of Load Expectation Working Group (LOLEWG) for its help. Stakeholder advice led to revisions in LOLE results, including updated transfer limits due to improved redispatch, use of existing Op Guides, and constraint invalidation, and two major LOLE modeling enhancements on off-peak wind modeling and planned outage scheduling to better reflect various resource availability throughout the year. Stakeholders also provided valuable feedback on the revised methodology for modeling planned outages which led to MISO revising the LRR results, recognizing the magnitude of changes in LRRs and need for a proper transition. MISO will, in collaboration with stakeholders, implement the new realistically optimized planned outage methodology for both PRM and LRR determination, with opportunities to fine tune as needed, in the 2022-23 PY LOLE study.[3]

[1] A one-day loss of load in 10 years (0.1 day/year) is not necessarily equal to 24 hours loss of load in 10 years (2.4 hours/year).
[2] "No Limit Found" reflects no valid constraint identified
[3] More information on planned outage modeling changes in appendix E

PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
PRM UCAP	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%
LRR UCAP per-unit of LRZ Peak Demand	1.147	1.145	1.171	1.269	1.250	1.147	1.212	1.361	1.155	1.527
Capacity Import Limit (CIL) (MW)	5,061	3,599	4,669	No Limit Found[2]	4,384	7,023	4,888	5,203	3,284	3,283
Capacity Export Limit (CEL) (MW)	2,474	3,488	No Limit Found[2]	4,886	No Limit Found[2]	4,710	No Limit Found[2]	No Limit Found[2]	2,790	1,369
Zonal Import Ability (ZIA) (MW)	5,059	3,599	4,556	5,141	4,384	6,738	4,888	5,155	3,284	3,283
Zonal Export Ability (ZEA) (MW)	2,476	3,488	NA[2]	5,804	NA[2]	4,995	NA[2]	NA[2]	2,790	1,369

Table 1-1: Initial Planning Resource Auction Deliverables



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, SIPC
5	AMMO, CWLD
6	BREC, CIN, HE, IPL, NIPSCO, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	EMBA, SME

Figure 1-1: Local Resource Zones (LRZ)

2 LOLE Study Process Overview

In compliance with Module E-1 of the MISO Tariff, MISO performed its annual LOLE study to determine the 2021-2022 PY MISO 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 transfer analysis to determine initial 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 2021-2022 per-unit LRR UCAP multiplied by the updated LRZ Peak Demand forecasts submitted for the 2021-2022 PRA determines each LRZ's LRR. Once the LRR is determined, the ZIA values and non-pseudo tied exports are subtracted from the LRR to determine each LRZ's Local Clearing Requirement (LCR) consistent with Section 68A.6[2] of Module E-1. An example calculation pursuant to Section 68A.6 of the current effective Module E-1[3] shows how these values are reached (Table 2-1).

The actual effective PRM Requirement (PRMR) will be determined after the updated LRZ Peak Demand forecasts are submitted by November 1, 2020, for the 2021-2022 PRA. The ZIA, ZEA, CIL and CEL values are subject to updates in March 2021 based on changes to exports of MISO resources to non-MISO load, changes to pseudo tied commitments, and updates to facility ratings since completion of the LOLE.

Finally, the simultaneous feasibility test (SFT) is performed as part of the PRA to ensure reliability and is maintained by adjusting CIL and CEL values as needed.

Local Resource Zone (LRZ) EXAMPLE	Example LRZ	Formula Key
Installed Capacity (ICAP)	17,442	[A]
Unforced Capacity (UCAP)	16,326	[B]
Adjustment to UCAP (1d in 10yr)	50	[C]
Local Reliability Requirement (LRR) (UCAP)	16,376	[D]=[B]+[C]
LRZ Peak Demand	14,270	[E]
LRR UCAP per-unit of LRZ Peak Demand	114.8%	[F]=[D]/[E]
Zonal Import Ability (ZIA)	3,469	[G]
Zonal Export Ability (ZEA)	2,317	[H]
Proposed PRA (UCAP) EXAMPLE	**Example LRZ**	**Formula Key**
Forecasted LRZ Peak Demand	14,270	[I]
Forecasted LRZ Coincident Peak Demand	13,939	[J]
Non-Pseudo Tied Exports UCAP	150	[K]
Local Reliability Requirement (LRR) UCAP	16,376	[L]=[F]x[I]
Local Clearing Requirement (LCR)	12,757	[M]=[L]-[G]-[K]
Planning Reserve Margin (PRM)	9.4%	[N]
Zone's System Wide PRMR	15,249	[O]=[1.094]X[J]
PRMR	15,249	[P]=Higher of [M] or [O]

2 https://www.misoenergy.org/legal/tariff/
3 Effective Date: October 28, 2019

Table 2-1: Example LRZ Calculation

2.1 Future Study Improvement Considerations

In response to stakeholder feedback received through the LOLEWG, MISO modified the Generation Limited Transfer methodology to report the Import or Export limits as "No Limit Found" if a valid constraint does not emerge upon executing a Generation Limited Transfer. BPM-011 is being updated to reflect this change.

This year, MISO implemented a methodology change in the LOLE model to better capture the risk associated with planned outages. Under previous Perfectly Optimized Outage approach, SERVM creates 30 unique outage schedules that are perfectly optimized for each of the 30 load shapes to avoid high load periods with perfect foresight. As a result, this approach significantly underestimates the level of planned outages during tight conditions. Under the new Realistically Optimized Planned Outage methodology, SERVM creates a single outage schedule that is optimized around the average of the 30 load shapes. This allows the model to capture scenarios where planned outages are scheduled during unseasonably high load periods in shoulder seasons that was not previously captured due to the perfect optimization. Although the new approach provides better alignment between modeled and actual planned outages compared to the perfectly optimized approach, the lengthy LRR analysis was not performed during the methodology development process, resulting in insufficient time for LSEs to adequately plan and prepare for the magnitude of changes in the new LRR values. Based on stakeholder feedback, MISO implemented the new Realistically Optimized Planned Outage methodology for the system wide PRM determination, and revised the initial LRR values for the Planning Year to reflect the perfect optimization as historically modeled. Going forward, MISO will continue to work with stakeholders to fine tune and implement the new realistically optimized outage methodology in the 2022-23 PY LOLE study, providing stakeholders ample awareness on expected changes to the zonal requirements.

3 Transfer Analysis

3.1 Calculation Methodology and Process Description

Transfer analyses determined preliminary CIL and CEL values for LRZs for the 2021-2022 Planning Year. Adjustments are made for Border External Resources (BERs) and Coordinating Owner Resources (COs) to determine the ZIA and ZEA. Further adjustments are made for exports to non-MISO Loads to arrive at the initial CIL and CEL values. The objective of transfer analysis is to determine constraints caused by the transfer of capacity between zones and the associated transfer capability. Multiple factors impacted the analysis when compared to previous studies, including:

- Completion of MTEP transmission projects
- Generation retirements and commissioning of new units
- External system dispatch changes

3.1.1 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 areas are the source subsystem. The LRZ studied for export limits is the source subsystem and the rest of MISO is the sink subsystem.

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 potentially masks 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 areas adjacent to the study zone. Since export study subsystems are defined by the 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 the zone because the ramped-up generation concentrates in a particular area.

3.1.2 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 in MISO operations. 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 units or wind plants
- 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

3.1.3 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 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 only occur after all the generation is dispatched at its maximum amount). If the LRZ experiences a GLT, MISO will adjust the base model based 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 dispatching all generation 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 rerun 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 dispatching all generation within the source subsystem, MISO will adjust load and generation in the source subsystem. This increases the import capacity 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(s), 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).

3.1.4 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.

3.2 Powerflow Models and Assumptions

3.2.1 Tools used

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

3.2.2 Inputs required

Thermal transfer analysis requires powerflow models and input files. MISO used contingency files from MTEP[4] reliability assessment studies. Single-element contingencies in MISO/seam areas were also evaluated.

MISO developed a subsystem file to monitor its footprint and seam areas. LRZ definitions were developed as sources and sinks in the study. See Appendix B 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.

3.2.3 Powerflow Modeling

The summer peak 2021 study model was built using MISO's Model on Demand (MOD) model data repository, with the following base assumptions (Table 3-1).

Scenario	Effective Date	Projects Applied	External Modeling	Load and Generation Profile
2021	6/1/2021	MTEP Appendix A and Target A	2019 Series 2021 Summer ERAG MMWG	Summer Peak

Table 3-1: 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
- 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

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

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 build for MTEP20 analyses, with study files made available on MISO ShareFile. MISO worked closely with transmission owners and stakeholders in order 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 analysis. This is driven partly by limited availability of outage information as well as current standard requirements. Although no outage schedules were evaluated, single element contingencies were evaluated. This includes BES lines, transformers, and generators. Contingency coverage covers most of category P1 and some of category P2.

3.2.4 General Assumptions

MISO uses TARA to process the powerflow model and associated input files to determine the 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 3-1). All published limits are based on the zone's FCTTC and may be adjusted for capacity exports.

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

Equation 3-1: Total Transfer Capability

Facilities were flagged as potential constraints for loadings of 100 percent or more in two scenarios: the normal rating for system intact conditions and the emergency rating for single event contingencies. 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 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 3-2 and Equation 3-2 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 3-2: 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 3-2: Machine 1 dispatch calculation for 100 MW transfer

3.3 Results for CIL/CEL and ZIA/ZEA

Study constraints and associated ZIA, ZEA, CIL, and CEL for each LRZ were presented and reviewed through the LOLEWG with results for the 2021-22 Planning Year presented during the October 20, 2020 meeting. Table 3-3 below shows the Planning Year 2021-22 CIL and ZIA with corresponding constraint, GLT, and redispatch information. Last year's CIL and ZIA results are also included for comparison.

This year was the first time a limit was not identified while calculating a CIL via a GLT. Because of this, a ZIA was calculated consistent with current process to facilitate calculating the LCR for LRZ 4 by applying the existing ZIA equation used for the CIL process:

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

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

The transfer into LRZ 4 is limited by the capacity available to export from its Tiers 1&2, Appendix B at the end of the report lists the LBAs within those tiers, therefore the Tier 1&2 export capacity can replace the FCITC in Equation 3-3 above. The calculated ZIA of 5,141 MW is comparable to last year. Moving forward, MISO will further examine the process for determining CIL in the absence of transmission limits at the Resource Adequacy Subcommittee (RASC) stakeholder forum. Differences in CIL between this year and last were driven by an east to west shift in generation in PJM for a majority of the LRZs; generation in ComEd increased while generation within ATSI, AEP, and DEOK decreased. Changes to generation, load, and topology in the MISO footprint and Seams also drove change.

LRZ	Tier	21-22 CIL (MW)	21-22 ZIA (MW)	Monitored Element	Contingent Element	GLT Applied	Generation Redispatch (MW)	20-21 CIL (MW)	20-21 ZIA (MW)
1	1&2	5,061	5,059	North Appleton to Werner West 345 kV	Weston Unit 4	Yes	0	3,231	3,225
2	1&2	3,599	3,599	Nelson Dewey 161/138 kV TR	Base Case	No	678	1,603	1,603
3	1&2	4,669	4,556	White to Split Rock 345 kV	Lakefield to Lakefield 3 345 kV	No	665	3,406	3,171
4	N/A	No Limit Found[5]	5,141[6]	No Constraint Found	--	Yes	0	6,092	4,809

[5] LRZ 4: "No Limit Found" reflects no valid constraint identified after GLT of 25%

[6] A ZIA was calculated by MISO to facilitate the calculation of the Local Clearing Requirement (LCR) for LRZ 4.
ZIA = FCITC + AI – Border External Resources & Coordinating Owners
Where FCITC = export capacity of Tiers 1 & 2 for LRZ 4

LRZ	Tier	21-22 CIL (MW)	21-22 ZIA (MW)	Monitored Element	Contingent Element	GLT Applied	Generation Redispatch (MW)	20-21 CIL (MW)	20-21 ZIA (MW)
5	1&2	4,384	4,384	Heritage Gardens to Fredericktown 161 kV	Lutesville to St Francois 345 kV	No	0	5,424	5,424
6	1&2	7,023	6,738	Cayuga Sub to Cayuga 345 kV	Kansas to Sugar Creek 345 kV	No	1,343	7,188	7,041
7	1&2	4,888	4,888	Palisades to Argenta 345 kV #2	Palisades to Argenta 345 kV #1	Yes	0	3,200	3,200
8	1&2	5,203	5,155	Gypsy to Fairview RCT 230 kV	McKnight to Franklin 500 kV	No	965	3,919	3,776
9	1	3,284	3,284	Camden Maquire to Smackover 115 kV	Camden Maquire to Mcneil 115 kV	No	1,828	3,712	3,410
10	1&2	3,283	3,283	Adams Creek to Angie 230 kV	French Branch to Logtown West 230 kV	No	1220	3,432	3,160

Table 3-3: Planning Year 2021–2022 Import Limits

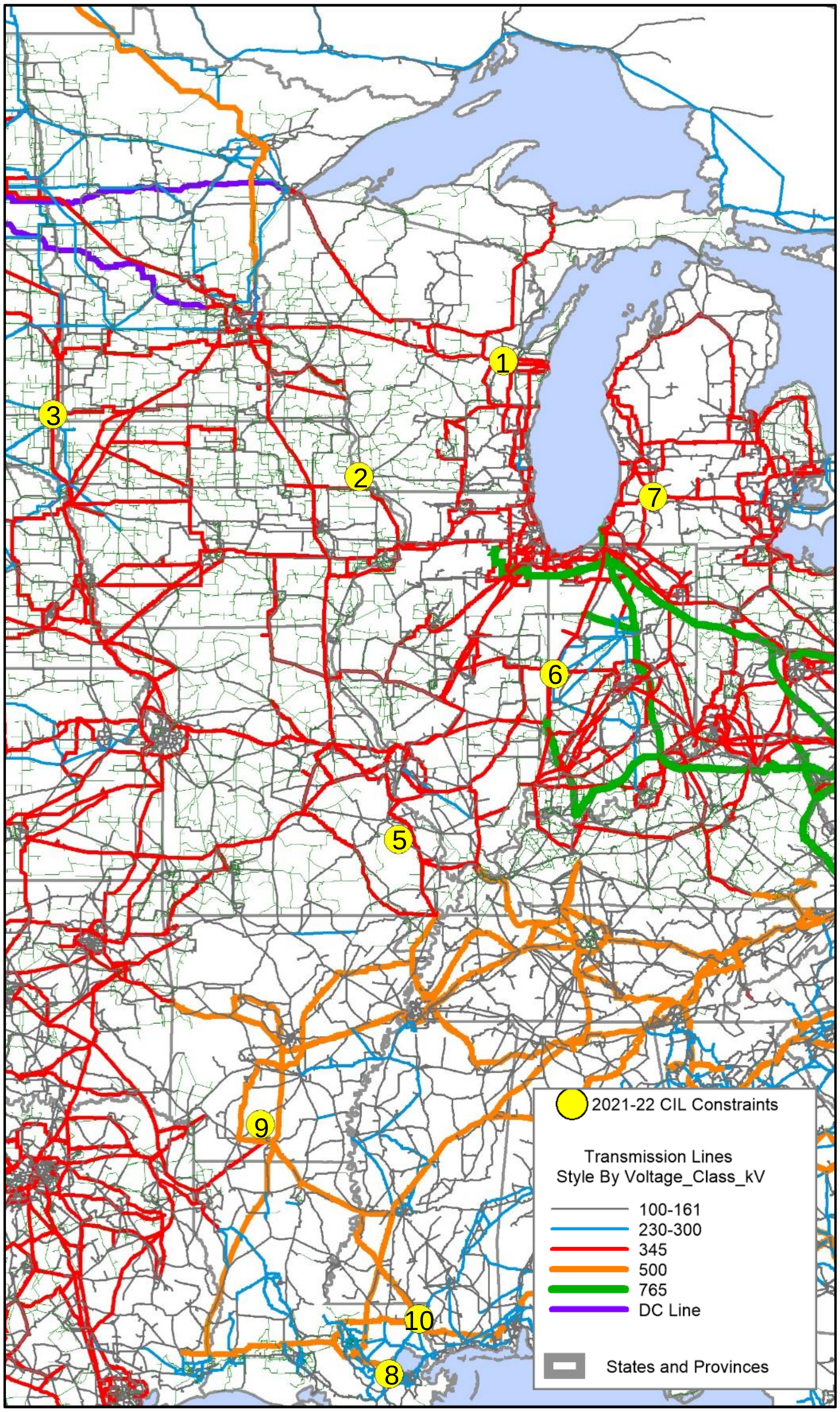


Figure 3-1: Planning Year 2021-22 Import Constraint Map

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 3-4 below shows the Planning Year 2021-22 CEL and ZEA with corresponding constraint, GLT, and redispatch information. Last year's CEL and ZEA results are also included for comparison.

LRZs 3, 5, 7, and 8 reported no limit found which is a repeat of what was found last year. Like the CIL results, the east to west shift in generation in PJM as well as changes to generation, load, and topology in the MISO footprint and Seams also drove changes to CEL.

LRZ	21-22 CEL (MW)[6]	21-22 ZEA (MW)	Monitored Element	Contingent Element	GLT Applied	Generation Redispatch (MW)	20-21 CEL (MW)	20-21 ZEA (MW)
1	2,474	2,476	Split Rock to White 345 kV	Lakefield to Lakefield 3 345 kV	Yes	0	3,772	3,778
2	3,488	3,488	Elm Road to Racine Bus 6 345 kV	Base Case	Yes	0	No Limit Found	N/A
3	No Limit Found[7]	N/A	No Constraint found		Yes	0	No Limit Found	N/A
4	4,886	5,804	Cayuga to Wallace 345 kV	Dresser to Sugar Creek 345 kV	Yes	1,134	3,771	5,053
5	No Limit Found[8]	N/A	No Constraint found		Yes	0	No Limit Found	N/A
6	4,710	4,995	Cayuga to Eugene 345 kV	Cayuga to Nucor 345 kV	Yes	0	4,761	4,907
7	No Limit Found[9]	N/A	No Constraint found		Yes	0	No Limit Found	N/A
8	No Limit Found[10]	N/A	No Constraint found		Yes	0	No Limit Found	N/A
9	2,790	2,790	Adams Creek to Angie 230 kV	Slidell to Logtown West 230 kV	No	0	1,616	1,918
10	1,369	1,369	Batesville to Tallahachie 161 kV	Choctaw to Clay 500 kV	Yes	0	1,385	1,658

Table 3-4: Planning Year 2021–2022 Export Limits

[7] LRZ 3: "No Limit Found" reflects no valid constraint identified after GLT of 45%
[8] LRZ 5: "No Limit Found" reflects no valid constraint identified after GLT of 20%
[9] LRZ 7: "No Limit Found" reflects no valid constraint identified after GLT of 50%
[10] LRZ 8: "No Limit Found" reflects no valid constraint identified after GLT of 50%

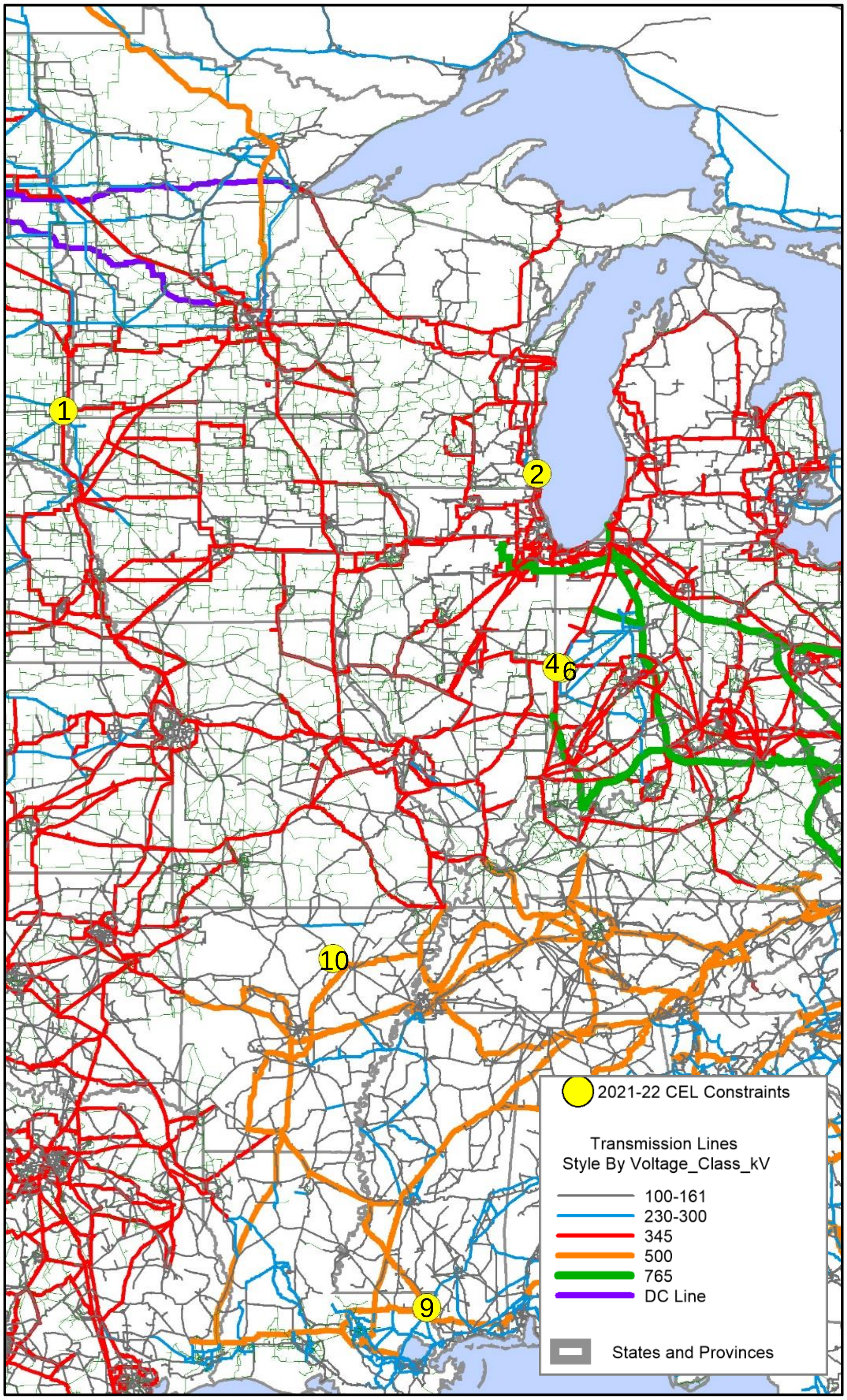


Figure 3-2: Planning Year 2021-22 Export Constraint Map

3.3.1 Out-Year Analysis

In 2018, MISO and its stakeholders redesigned the out-year LOLE transfer analysis process through the LOLEWG and Resource Adequacy Subcommittee (RASC). The out-year analysis is now performed after the planning year analyses are complete. The out-year results will be documented outside of the LOLE report and recorded in LOLEWG meeting materials.

4 Loss of Load Expectation Analysis

4.1 LOLE Modeling Input Data and Assumptions

MISO uses a program managed by Astrapé Consulting called SERVM to calculate the 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 the annual LOLE for the MISO system and 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 PRM study. Many scenarios are built in order to determine how certain variables impact the results. The base case models determine the MISO PRM Installed Capacity (ICAP), PRM UCAP and the LRRs for each LRZ for years one, four and six.

Two LOLE modeling improvements were made for the 2021-2022 LOLE study as a result the Resource Availability and Need (RAN) initiative to better reflect variability and availability of various resources throughout the year. The first improvement was made to Planned/Maintenance Outage modeling assumptions. Previously, Planned/Maintenance Outages were perfectly optimized in the model in order to maximize reserves at all times with perfect foresight. This approach significantly underestimated risk, particularly in non-summer months. For the 2021 LOLE MISO system wide PRM analysis, MISO implemented the more realistic outage scheduling to allow planned outages to take place during unseasonably tight conditions in shoulder seasons, which better align with historical experience. Based on stakeholder feedback, the revised approach was not applied to the LRR determination due to the magnitude of changes in LRR values and need for ample awareness and transition. However, MISO applied this revised methodology to both the PRM and LRR's for the out-year analyses to inform stakeholders of potential LRR impacts of modeling planned outages more realistically for their awareness. MISO will continue to work with stakeholders to fine tune and implement the new realistically optimized outage methodology in the 2022-23 PY LOLE study.

The second LOLE modeling improvement made in the 2021 LOLE study was the treatment of wind resources. Historically, wind was modeled as a flat capacity value throughout the year which was equal to each wind unit's capacity credit calculated from the annual Effective Load Carrying Capability (ELCC) study. This year wind was modeled with monthly capacity values to better reflect the monthly variation of wind resource across the year.

4.2 MISO Generation

4.2.1 Thermal Units

The 2021-2022 planning year LOLE study used the 2020 PRA converted capacity as a starting point for which resources to include in the study. This ensured that only resources eligible as a Planning Resources were included in the LOLE study. An exception was made for resources with a signed GIA with an anticipated in-service date for the 2021-2022 PY. These resources were also included. All internal Planning Resources were modeled in the LRZ in which they are physically located. Additionally, Coordinating Owners and Border External Resources were modeled as being internal to the LRZ in which they are committed to serving load.

Forced outage rates and planned maintenance factors were calculated over a five-year period (January 2015 to December 2019) and modeled as one value for each unit. Some units did not have five years of historical data in MISO's Generator Availability Data System (PowerGADS). However, if they had at least 12 consecutive months of data then unit-specific information was used to calculate their forced outage rates and maintenance factors. Units with fewer than 12 consecutive months of unit-specific data were assigned the corresponding MISO class average forced outage rate and planned maintenance factor based on their fuel type. Any MISO class with fewer than 30 units were assigned the overall MISO weighted class average forced outage rate of 9.36 percent. When the units are populated into the LOLE model, The weighted outage rate in SERVM might be different from the calculated MISO-wide weighted average because the MISO-wide weighted average excludes units with insufficient operating history. Therefore, the weighted outage rate is recalculated to include units that were assigned class average outage rates to gauge how SERVM views the MISO-wide weighted average. This value is for information only and is not assigned to any units.

Nuclear units have 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 fleet wide weighted average forced outage rate are in Table 4-1.

Pooled EFORd GADS Years	2015-2019 (%)	2014-2018 (%)	2013-2017 (%)	2012-2016 (%)	2011-2015 (%)	2010-2014 (%)
LOLE Study Planning Year	2021-2022 PY LOLE Study	2020-2021 PY LOLE Study	2019-2020 PY LOLE Study	2018-2019 PY LOLE Study	2017-2018 PY LOLE Study	2016-2017 PY LOLE Study
Combined Cycle	5.52	5.7	5.37	4.62	3.56	3.78
Combustion Turbine (0-20 MW)	36.38	40.39	23.18	29.02	24.2	23.58
Combustion Turbine (20-50 MW)	14.20	15.29	15.76	13.48	13.94	16.03
Combustion Turbine (50+ MW)	4.76	4.65	5.18	6.19	5.94	5.69
Diesel Engines	10.05	23.53	10.26	10.42	13.12	12.51
Fluidized Bed Combustion	*	*	*	*	*	*
HYDRO (0-30MW)	*	*	*	*	*	*
HYDRO (30+ MW)	*	*	*	*	*	*
Nuclear	*	*	*	*	*	*
Pumped Storage	*	*	*	*	*	*
Steam - Coal (0-100 MW)	*	5.33	4.60	5.14	5.99	7.12
Steam - Coal (100-200 MW)	*	*	*	*	*	*

Steam - Coal (200-400 MW)	10.47	10.16	9.82	9.77	8.64	8.46
Steam - Coal (400-600 MW)	*	*	*	*	*	7.04
Steam - Coal (600-800 MW)	*	*	8.22	7.90	7.42	7.58
Steam - Coal (800-1000 MW)	*	*	*	*	*	*
Steam - Gas	12.91	12.54	11.56	11.94	11.68	10.18
Steam - Oil	*	*	*	*	*	*
Steam - Waste Heat	*	*	*	*	*	*
Steam - Wood	*	*	*	*	*	*
MISO System Wide Weighted	9.36	9.24	9.28	9.16	8.21	7.98
MISO Weighted as seen in SERVM	9.17	9.22	9.18	-	-	-

*MISO system-wide weighted forced outage rate used in place of class data for those with less than 30 units reporting 12 or more months of data
**Prior to 2015-2016PY the NERC class average outage rate was used for units with less than 30 units reporting 12 or more months of data

Table 4-1: Historical Class Average Forced Outage Rates

4.2.2 Behind-the-Meter Generation

Behind-the-Meter generation data came from the Module E Capacity Tracking (MECT) tool. These resources were explicitly modeled just as any other thermal generator with a monthly capacity and forced outage rate. Performance data was pulled from PowerGADS.

4.2.3 Sales

The LOLE analysis incorporates firm sales to neighboring capacity markets as well as firm transactions off system where information was available. For units with capacity sold off-system, the monthly capacities were reduced by the megawatt amount sold. This totaled 2,419 MW UCAP for Planning Year 2021-2022. See Section 4.4 for a more detailed breakdown. These values came from PJM's Reliability Pricing Model (RPM) as well as exports to other external areas taken from the Independent Market Monitor (IMM) exclusion list.

4.2.4 Attachment Y

For the 2021-2022 planning year, generating units with approved suspensions or retirements (as of June 1, 2020) through MISO's Attachment Y process were removed from the LOLE analysis. Any unit retiring, suspending, or coming back online at any point during the planning year was excluded from the year-one analysis. This same methodology is used for the four- and six-year analyses.

4.2.5 Future Generation

Future thermal generation and upgrades were added to the LOLE model based on unit information in the MISO Generator Interconnection Queue. The LOLE model included units with a signed interconnection agreement (as of June 1, 2020). These new units were assigned class-average forced outage rates and planned maintenance factors based on their particular unit class. Units upgraded during the study period reflect the megawatt increase for each month, beginning the month the upgrade was finished. The LOLE analysis also included future wind generation at the MISO average monthly wind ELCC values and future solar at 50% capacity credit. Going forward, MISO will also include any future contracts for firm imports in the LOLE analysis.

4.2.6 Intermittent Resources

Intermittent resources such as run-of-river hydro, biomass and wind were explicitly modeled as demand-side resources. Non-wind intermittent resources, such as run-of-river hydro and biomass, provide MISO with up to 15 years of historical summer output data for the hours ending 15:00 EST through 17:00 EST. This data is averaged and modeled in the LOLE analysis as UCAP for all months. Each individual unit is modeled and put in the corresponding LRZ.

Each wind resource Commercial Pricing Node (CPNode) received monthly capacity values based on its historical output from MISO's top eight peak days in each month of the past ten years. The megawatt value corresponding to each CPNode's calculated wind capacity value was unique for each month of the year. Units new to the commercial model without a wind capacity credit as part of the 2020 Wind Capacity Credit analysis received the MISO-wide monthly average ELCC values. The detailed methodology for establishing the MISO-wide and individual CPNode Wind Capacity Credits can be found in the 2020 Wind Capacity Credit Report. The monthly wind capacity values were allocated across each existing wind resource to develop individual monthly capacity values, following a similar deterministic process used in the annual Wind Capacity Credit study but at the monthly granularity. The results of the monthly wind ELCC simulations (expressed as percentages) are shown below (Figure 4-1).

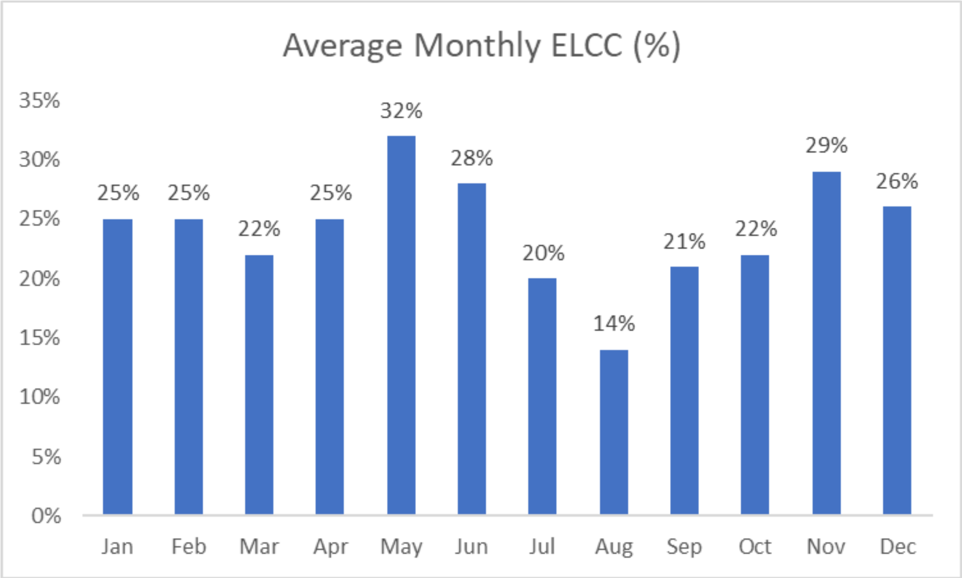


Figure 4-1: Monthly Average Wind ELCC

4.2.7 Demand Response

Demand response data 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 to the number of times each program can be called upon, and limited by duration.

4.3 MISO Load Data

The 2021-2022 LOLE analysis used a load training process with neural net software to create a neural-net relationship between historical weather and load data. This relationship was then applied to 30 years of hourly historical weather data to create 30 different load shapes for each LRZ in order to capture both load diversity and seasonal variations. The average monthly loads of the predicted load shapes were adjusted to match each LRZ's Module E 50/50 monthly zonal peak load forecasts for each study year. The results of this process are shown as the MISO System Peak Demand (Table 5-1) and LRZ Peak Demands (Table 6-1).

Direct Control Load Management and Interruptible Demand types of demand response were explicitly included in the LOLE model as resources. These demand resources are implemented in the LOLE simulation before accumulating LOLE or shedding of firm load.

4.3.1 Weather Uncertainty

MISO has adopted a six-step load training process in order to capture the weather uncertainty associated with the 50/50 load forecasts. The first step of this process requires the collection of five years of historical real-time load modifying resource (LMR) performance and load data, as well as the collection of 30 years of historical weather data. Both the LMR and load data are taken from the MISO market 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 five years of historical data.

The second step of the process is to normalize the five years of load data to consistent economics. With the load growth due to economics removed from 5 years of historical LRZ load, the third step of the process utilizes neural network software to establish functional relationships between the five years of historical weather and load data. In the fourth step of the process the neural network relationships are applied to the 30 years of historical weather data in order to predict/create 30 years' worth of load shapes for each LRZ.

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 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 network 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 Module E 50/50 monthly zonal peak load forecasts for each study year. In order 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 year's non-coincident peak forecast.

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

4.3.2 Economic Load Uncertainty

To account for economic load uncertainty in the 2021-2022 planning year 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 electric use was taken from the U.S. Energy Information Administration (EIA). Due to lack of statewide projected GDP data MISO relied on United States aggregate level data when calculating the economic uncertainty.

In order to calculate the electric utility forecast error, MISO first calculated the forecast error of GDP between the projected 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 the 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 4-2.

	LFE Levels				
	-2.0%	-1.0%	0.0%	1.0%	2.0%
Standard Deviation in LFE	Probability assigned to each LFE				
0.92%	5.2%	24.2%	41.3%	24.2%	5.2%

Table 4-2: Economic Uncertainty

As a result of stakeholder feedback MISO is exploring possible alternative methods for determining economic uncertainty to be used in the LOLE process.

4.4 External System

Within the LOLE study, a 1 MW increase of non-firm support from external areas leads to a 1 MW decrease in the reserve margin calculation. It is important to account for the benefit of being part of the eastern interconnection while also providing a stable result. Historically, MISO modeled the external system, including non-firm imports, in the LOLE study which resulted in year-over-year volatility in the PRM. In order to provide a more stable result and remove the false sense of precision, the external non-firm support was set at an ICAP of 2,987 MW and a UCAP of 2,331 MW in the 2015 LOLE study and has remained constant since then.

Firm imports from external areas to MISO are modeled at the individual unit level. The specific external units were modeled with their specific installed capacity amount and their corresponding Equivalent Forced Outage Rate demand (EFORd). This better captures the probabilistic reliability impact of firm external imports. These units are only modeled within the MISO PRM analysis and are not modeled when calculating the LRZ LRRs. Due to the locational Tariff filing, Border and Coordinating Owners External Resources are no longer considered firm imports. Instead, these resources are modeled as internal MISO units and are included in the PRM and LRR analysis. The external resources to include for firm imports were based on the amount offered into the 2019-20 planning year PRA. This is a historically accurate indicator of future imports. For 2020-21 planning year this amount was 1,775 MW ICAP.

Firm exports from MISO to external areas were modeled the same as previous years. As stated in Section 4.2.3, capacity ineligible as MISO capacity due to transactions with external areas is removed from the model. Table 4-3 shows the amount of firm imports and exports in this year's study.

Contracts	ICAP (MW)	UCAP (MW)
Imports (MW)	1,775	1,723
Exports (MW)	2,610	2,419
Net	**-835**	**-697**

Table 4-3: 2020 Planning Year Firm Imports and Exports

4.5 Loss of Load Expectation Analysis and Metric Calculations

Upon completion of the SERVM database, MISO determined the appropriate PRM ICAP and PRM UCAP for the 2021-2022 planning year as well as the appropriate Local Reliability Requirement for each of the 10 LRZs. These metrics were determined by a probabilistic LOLE analysis such that the LOLE for the planning year was 1 day in 10 years, or 0.1 day per year.

4.5.1 MISO-Wide LOLE Analysis and PRM Calculation

For the MISO-wide analysis, generating units were modeled as part of their appropriate LRZ as a subset of a larger MISO pool. The MISO system was modeled with no internal transmission limitations. In order to meet the reliability criteria of 0.1 day per year LOLE, capacity is either added or removed from the MISO pool. The minimum amount of capacity above the 50/50 net internal MISO Coincident Peak Demand required to meet the reliability criteria was used to establish the PRM values.

The minimum PRM requirement is determined using the LOLE analysis by either adding or removing capacity until the LOLE reaches 0.1 day per year. If the LOLE is less than 0.1 day per year, a perfect negative unit with zero forced outage rate is added until the LOLE reaches 0.1 day per year. The perfect negative unit adjustment is akin to adding load to the model. If the LOLE is greater than 0.1 day per year, proxy units based on a unit of typical size and forced outage rate will be added to the model until the LOLE reaches 0.1 day per year.

For the 2021-2022 planning year, the MISO PRM analysis removed capacity (8,081 MW) using the perfect unit adjustment and applies to both the PRM ICAP and PRM UCAP.

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

PRM ICAP = ((Installed Capacity + Firm External Support ICAP + ICAP Adjustment to meet a LOLE of 0.1 days per year) – MISO Coincident Peak Demand)/MISO Coincident Peak Demand

PRM UCAP = (Unforced Capacity + Firm External Support UCAP + UCAP Adjustment to meet a LOLE of 0.1 days per year) – MISO Coincident Peak Demand)/MISO Coincident Peak Demand

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

4.5.2 LRZ LOLE Analysis and Local Reliability Requirement Calculation

For the LRZ analysis, each LRZ included only the generating units within the LRZ (including Coordinating Owners and Border External Resources) and was modeled without consideration of the benefit of the LRZ's import capability. Much like the MISO analysis, unforced capacity is either added or removed in each LRZ such that a LOLE of 0.1 day per year is achieved. The minimum amount of unforced capacity above each LRZ's Peak Demand that was required to meet the reliability criteria was used to establish each LRZ's LRR.

The 2021-2022 LRR is determined using the LOLE analysis by either adding or removing capacity until the LOLE reaches 0.1 day per year for the LRZ. If the LOLE is less than 0.1 day per year, a perfect negative unit with zero forced outage rate will be added until the LOLE reaches 0.1 day per year. If the LOLE is greater than 0.1 day per year, proxy units based on a unit of typical size and forced outage rate will be added to the model until the LOLE reaches 0.1 day per year.

For the 2021-2022 planning year, only LRZ-1, LRZ-3, and LRZ-8 had sufficient capacity, internal to the LRZ to achieve the LOLE of 0.1 day per year as an island. In the seven zones without sufficient capacity as an island, proxy units of typical size (160 MW) and class-average EFORd (4.76 percent) were added to the LRZ. When needed, a fraction of the final proxy unit was added to achieve the exact LOLE of 0.1 day per year for the LRZ.

LRR UCAP = (Unforced Capacity + UCAP Adjustment to meet a LOLE of 0.1 days per year – Zonal Coincident Peak Demand)/Zonal Coincident Peak Demand

5 MISO System Planning Reserve Margin Results

5.1 Planning Year 2021-2022 MISO Planning Reserve Margin Results

For the 2021-2022 planning year, the ratio of MISO capacity to forecasted MISO system peak demand yielded a planning ICAP reserve margin of 18.3 percent and a planning UCAP reserve margin of 9.4 percent. These PRM values assume 1,723 MW UCAP of firm and 2,331 MW UCAP of non-firm external support. Numerous values and calculations went into determining the MISO system PRM ICAP and PRM UCAP (Table 5-1).

MISO Planning Reserve Margin (PRM)	**2021/2022 PY** (June 2021 - May 2022)	**Formula Key**
MISO System Peak Demand (MW)	124,451	[A]
Installed Capacity (ICAP) (MW)	156,485	[B]
Unforced Capacity (UCAP) (MW)	144,894	[C]
Firm External Support (ICAP) (MW)	1,775	[D]
Firm External Support (UCAP) (MW)	1,723	[E]
Adjustment to ICAP {1d in 10yr} (MW)	-8,081	[F]
Adjustment to UCAP {1d in 10yr} (MW)	-8,081	[G]
Non-Firm External Support (ICAP) (MW)	2,987	[H]
Non-Firm External Support (UCAP) (MW)	2,331	[I]
ICAP PRM Requirement (PRMR) (MW)	147,192	[J]=[B]+[D]+[F]-[H]
UCAP PRM Requirement (PRMR) (MW)	136,205	[K]=[C]+[E]+[G]-[I]
MISO PRM ICAP	**18.3%**	[L]=([J]-[A])/[A]
MISO PRM UCAP	**9.4%**	[M]=([K]-[A])/[A]

Table 5-1: Planning Year 2021-2022 MISO System Planning Reserve Margins

5.1.1 LOLE Results Statistics

In addition to the LOLE results SERVM has the ability to calculate several other probabilistic metrics (Table 5-2). These values are given when MISO is at its PRM UCAP of 9.4 percent. The LOLE of 0.1 day/year is what the model is driven to and how the PRM is calculated. The 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 (EUE) 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 capacity across all hours.

MISO LOLE Statistics	
Loss of Load Expectation - LOLE [Days/Yr]	0.100
Loss of Load Hours - LOLH [hrs/yr]	.300
Expected Unserved Energy - EUE [MWh/yr]	599.4

Table 5-2: MISO Probabilistic Model Statistics

5.2 Comparison of PRM Targets Across 10 Years

Error! Reference source not found. compares the PRM UCAP values over the last 10 planning years. T he last endpoint of the blue line shows the Planning Year 2021-2022 PRM value.

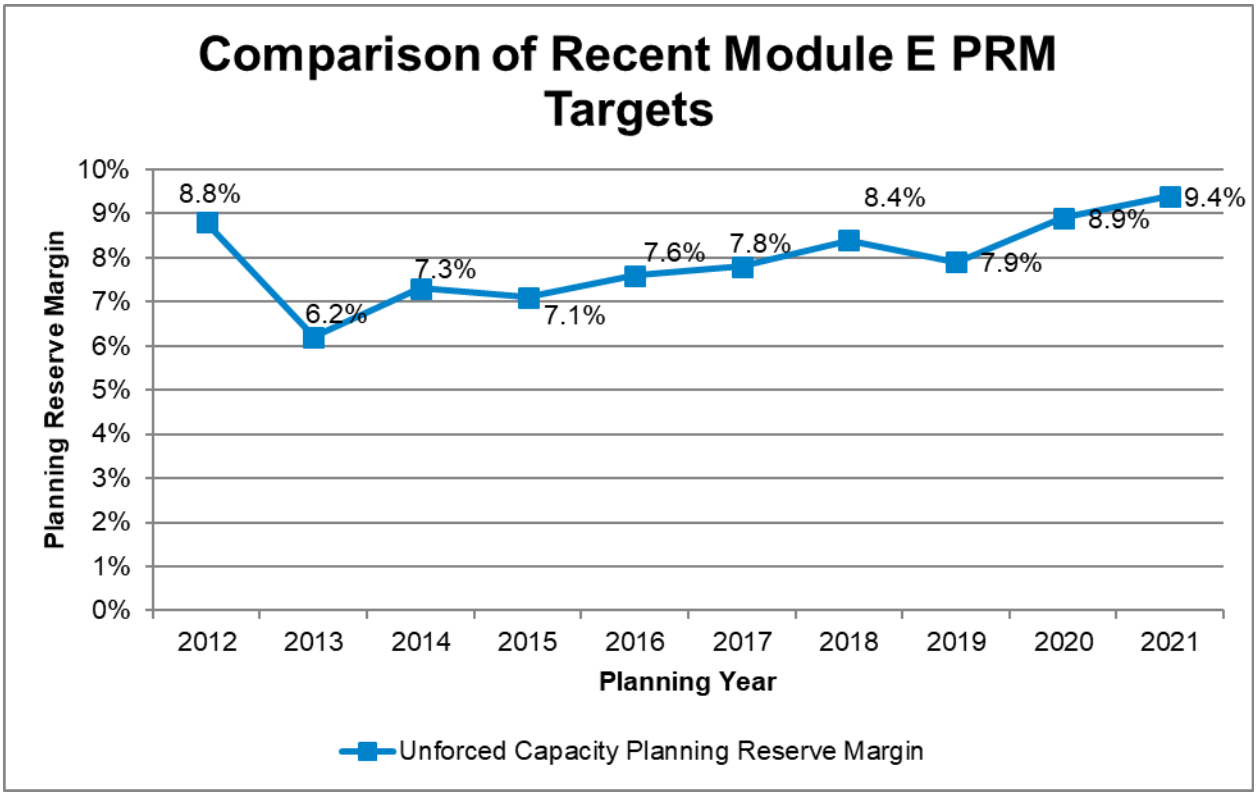


Figure 5-1: Comparison of PRM targets across ten years

5.3 Future Years 2021 through 2030 Planning Reserve Margins

Beyond the planning year 2021-2022 LOLE study analysis, an LOLE analysis was performed for the four-year-out planning year of 2024-2025, and the six-year-out planning year of 2026-2027. Table 5-3 shows all the values and calculations that went into determining the MISO system PRM ICAP and PRM UCAP values for those years. Those results are shown as the underlined values of Table 5-4. The values from the intervening years result from interpolating the 2021, 2024, and 2026 results. Note that the MISO system PRM results assume no limitations on transfers within MISO.

The 2024-2025 and 2026-2027 planning year PRM decreased slightly from the 2021-2022 planning year driven mainly by new unit additions and retirements.

MISO Planning Reserve Margin (PRM)	**2024/2025 PY** (June 2024 - May 2025)	**2026/2027 PY** (June 2026 - May 2027)	**Formula Key**
MISO System Peak Demand (MW)	126,212	126,776	[A]
Installed Capacity (ICAP) (MW)	160,369	165,174	[B]
Unforced Capacity (UCAP) (MW)	149,278	152,800	[C]
Firm External Support (ICAP) (MW)	1,775	1,775	[D]
Firm External Support (UCAP) (MW)	1,723	1,723	[E]
Adjustment to ICAP {1d in 10yr} (MW)	-10,842	-14,210	[F]
Adjustment to UCAP {1d in 10yr} (MW)	-10,842	-14,210	[G]
Non-Firm External Support (ICAP) (MW)	2,987	2,987	[H]
Non-Firm External Support (UCAP) (MW)	2,331	2,331	[I]
ICAP PRM Requirement (PRMR) (MW)	148,315	149,752	[J]=[B]+[D]+[F]-[H]
UCAP PRM Requirement (PRMR) (MW)	137,828	137,982	[K]=[C]+[E]+[G]-[I]
MISO PRM ICAP	17.5%	18.1%	[L]=([J]-[A])/[A]
MISO PRM UCAP	9.2%	8.8%	[M]=([K]-[A])/[A]

Table 5-3: Future Planning Year MISO System Planning Reserve Margins

Metric	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
ICAP (GW)	158.3	161.6	160.9	162.1	164.3	166.9	166.9	166.9	166.9	166.9
Demand (GW)	124.5	125.1	125.6	126.2	126.2	126.8	127.4	127.9	128.3	128.8
PRM_{ICAP}	**18.3%**	**18.0%**	**17.8%**	**17.5%**	**17.8%**	**18.1%**	**17.8%**	**17.7%**	**17.7%**	**17.6%**
PRM_{UCAP}	**9.4%**	**9.3%**	**9.3 %**	**9.2%**	**9.0%**	**8.8%**	**8.7%**	**8.6%**	**8.5%**	**8.4%**

Table 5-4: MISO System Planning Reserve Margins 2021 through 2030
(Years without underlined results indicate PRM values that were calculated through interpolation)

6 Local Resource Zone Analysis – LRR Results

6.1 Planning Year 2021-2022 Local Resource Zone Analysis

MISO calculated the per-unit LRR of LRZ Peak Demand for years one, four and six (Table 6-1, Table 6-2, and Table 6-3). MISO applied the revised planning outage methodology to the LRR determination for the out-year analyses to inform stakeholders of potential LRR impacts of modeling planned outages more realistically for their awareness. The UCAP values in Table 6-1 reflect the UCAP within each LRZ, including Border External Resources and Coordinating Owners. The adjustment to UCAP values are the megawatt adjustments needed in each LRZ so that the reliability criterion of 0.1 days per year LOLE is met. The LRR is the summation of the UCAP and adjustment to UCAP megawatts. The LRR is then divided by each LRZ's Peak Demand to determine the per-unit LRR UCAP. The 2021-2022 per unit LRR UCAP values will be multiplied by the updated demand forecasts submitted for the 2021-2022 PRA to determine each LRZ's LRR. The zonal peak demand timestamps for all 30 weather years modeled in SERVM is shown in table 6-4. 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
2021-2022 Planning Reserve Margin (PRM) Study											
Installed Capacity (ICAP) (MW)	22,190	14,920	12,459	11,526	8,833	18.738	24,164	11,583	25,723	6,348	[A]
Unforced Capacity (UCAP) (MW)	21,108	14,120	11,942	10,439	7,911	17,225	22,249	10,956	23,573	5,368	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-775	605	-590	1,052	1,962	2,791	2,805	-395	791	1,867	[C]
LRR (UCAP) (MW)	20,333	14,725	11,352	11,491	9,873	20,016	25,054	10,561	24,364	7,235	[D]=[B]+[C]
Peak Demand (MW)	17,722	12,865	9,694	9,059	7,899	17,447	20,663	7,761	21,098	4,739	[E]
LRR UCAP per-unit of LRZ Peak Demand	**114.7%**	**114.5%**	**117.1%**	**126.9%**	**125.0%**	**114.7%**	**121.2%**	**136.1%**	**115.5%**	**152.7%**	[F]=[D]/[E]

Table 6-1: Planning Year 2021-2022 LRZ Local Reliability Requirements

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
2024-2025 Planning Reserve Margin (PRM) Study											
Installed Capacity (ICAP) (MW)	22,670	15,635	13,394	11,913	8,903	18,445	24,449	12,435	26,107	6,398	[A]
Unforced Capacity (UCAP) (MW)	21,572	14,835	12,873	10,897	7,980	17,114	22,875	11,740	23,952	5,418	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-524	500	-1,248	811	1,943	3,810	3,353	-800	2,829	1,983	[C]
LRR (UCAP) (MW)	21,048	15,335	11,625	11,707	9,923	20,924	26,228	10,940	26,780	7,401	[D]=[B]+[C]
Peak Demand (MW)	18,139	13,063	9,912	9,114	7,928	17,935	20,360	7,916	21,598	4,846	[E]
LRR UCAP per-unit of LRZ Peak Demand	**116.0%**	**117.4%**	**117.3%**	**128.4%**	**125.2%**	**116.7%**	**128.8%**	**138.2%**	**124.0%**	**152.7%**	[F]=[D]/[E]

Table 6-2: Planning Year 2024-2025 LRZ Local Reliability Requirements

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
2026-2027 Planning Reserve Margin (PRM) Study											
Installed Capacity (ICAP) (MW)	22,670	16,197	13,394	12,466	8,903	20,062	26,523	12,435	26,107	6,398	[A]
Unforced Capacity (UCAP) (MW)	21,572	15,366	12,873	11,379	7,980	18,518	24,511	11,740	23,952	5,418	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-266	48	-1,268	357	1,981	2,953	1,924	-703	3,115	2,029	[C]
LRR (UCAP) (MW)	21,306	15,413	11,605	11,736	9,962	21,471	26,435	11,037	27,066	7,447	[D]=[B]+[C]
Peak Demand (MW)	18,413	13,138	9,894	9,098	7,968	17,988	20,167	7,960	21,880	4,912	[E]
LRR UCAP per-unit of LRZ Peak Demand	**115.7%**	**117.3%**	**117.3%**	**129.0%**	**125.0%**	**119.4%**	**131.1%**	**138.7%**	**123.7%**	**151.6%**	[F]=[D]/[E]

Table 6-3: Planning Year 2026-2027 LRZ Local Reliability Requirements

Weather Year Time of Peak Demand (ESTHE)	MISO	LRZ-1	LRZ-2	LRZ-3	LRZ-4	LRZ-5	LRZ-6	LRZ-7	LRZ-8	LRZ-9	LRZ-10
		MN/ND	WI	IA	IL	MO	IN	MI	AR	LA/TX	MS
1990	8/28/90 15:00	7/3/90 18:00	8/28/90 14:00	7/3/90 16:00	9/6/90 16:00	8/28/90 16:00	7/9/90 18:00	8/28/90 15:00	7/3/90 17:00	8/6/90 17:00	8/21/90 17:00
1991	7/19/91 16:00	7/16/91 18:00	7/18/91 15:00	7/6/91 18:00	7/6/91 16:00	8/2/91 17:00	8/2/91 17:00	7/20/91 14:00	7/23/91 17:00	7/13/91 17:00	7/2/91 14:00
1992	8/10/92 16:00	8/9/92 16:00	8/10/92 18:00	7/8/92 16:00	8/9/92 16:00	7/2/92 16:00	1/16/92 7:00	8/10/92 16:00	8/10/92 17:00	7/11/92 18:00	7/12/92 17:00
1993	7/27/93 17:00	7/27/93 17:00	8/27/93 14:00	8/22/93 18:00	7/27/93 15:00	7/27/93 16:00	7/25/93 16:00	7/9/93 15:00	7/31/93 15:00	8/14/93 16:00	7/31/93 16:00
1994	7/5/94 17:00	6/14/94 19:00	6/29/91 17:00	7/19/94 19:00	6/19/94 18:00	7/5/94 17:00	1/19/94 6:00	6/18/94 17:00	6/29/94 18:00	8/14/94 17:00	1/19/94 9:00
1995	7/13/95 17:00	7/3/90 18:00	7/18/91 15:00	7/13/95 18:00	7/13/95 16:00	7/13/95 16:00	7/13/95 16:00	7/13/95 17:00	8/17/95 14:00	8/16/95 16:00	8/31/95 16:00
1996	8/7/96 16:00	8/6/96 17:00	6/29/96 17:00	7/18/96 18:00	7/18/96 18:00	7/18/96 19:00	7/19/96 15:00	8/7/96 16:00	7/20/96 15:00	2/5/96 7:00	7/3/96 18:00
1997	7/26/97 16:00	7/16/97 18:00	7/16/97 17:00	7/25/97 17:00	6/27/97 19:00	7/26/97 16:00	7/27/97 16:00	7/16/97 16:00	7/27/97 17:00	8/17/97 16:00	7/25/97 16:00
1998	7/20/98 16:00	7/13/98 18:00	6/25/98 16:00	7/20/98 19:00	7/20/98 16:00	7/20/98 17:00	7/19/98 17:00	6/25/98 18:00	8/28/98 16:00	8/28/98 17:00	8/27/98 15:00
1999	7/30/99 16:00	7/25/99 17:00	7/18/91 15:00	7/30/99 17:00	7/19/99 0:00	7/30/99 17:00	7/30/99 15:00	7/30/99 14:00	7/25/99 17:00	8/14/99 18:00	8/2/99 17:00
2000	8/31/00 16:00	8/14/00 19:00	7/14/00 16:00	8/31/00 17:00	9/1/00 16:00	8/17/00 17:00	9/1/00 15:00	9/1/00 15:00	8/28/98 16:00	8/30/00 16:00	8/30/00 16:00

2001	8/8/01 16:00	8/6/01 17:00	8/9/01 18:00	7/31/01 16:00	7/23/01 17:00	8/22/01 16:00	8/7/01 17:00	8/8/01 16:00	8/9/01 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 16:00	7/9/02 15:00	8/1/02 16:00	8/3/02 18:00	7/3/02 16:00	7/10/02 15:00	8/2/02 19:00	7/6/02 17:00
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 15:00	8/17/03 18:00	8/10/03 18:00	7/17/03 17:00
2004	7/13/04 16:00	6/7/04 17:00	6/8/04 17:00	7/20/04 17:00	7/13/04 16:00	7/13/04 17:00	1/31/04 4:00	7/21/04 16:00	7/14/04 16:00	8/1/04 17:00	7/25/04 15:00
2005	7/24/05 17:00	7/17/05 17:00	7/18/91 15:00	7/23/05 18:00	7/24/05 17:00	7/24/05 18:00	7/25/05 17:00	7/24/05 17:00	8/21/05 18:00	7/25/05 16:00	8/21/05 15:00
2006	7/31/06 17:00	7/3/90 18:00	8/1/06 17:00	7/19/06 18:00	7/31/06 18:00	8/2/06 18:00	7/31/06 16:00	7/31/06 17:00	7/19/06 17:00	8/15/06 17:00	8/15/06 17:00
2007	8/1/07 17:00	8/10/07 17:00	8/2/07 15:00	7/17/07 16:00	8/28/07 16:00	8/15/07 18:00	8/29/07 15:00	6/18/07 16:00	8/15/07 17:00	8/9/07 17:00	8/14/07 17:00
2008	7/16/08 17:00	7/11/08 19:00	7/30/08 17:00	8/3/08 15:00	7/20/08 18:00	7/20/08 16:00	9/3/08 15:00	8/24/08 13:00	8/2/08 17:00	8/28/08 16:00	7/27/08 16:00
2009	6/25/09 16:00	6/22/09 20:00	7/28/09 16:00	8/8/09 17:00	6/25/09 17:00	8/9/09 16:00	1/16/09 8:00	8/9/09 17:00	6/22/09 16:00	7/2/09 16:00	6/28/09 14:00
2010	8/10/10 17:00	8/8/10 18:00	8/20/10 14:00	7/17/10 18:00	8/10/10 17:00	8/3/10 16:00	8/13/10 16:00	9/1/10 15:00	8/28/98 16:00	8/1/10 17:00	8/2/10 16:00
2011	7/20/11 18:00	6/7/11 17:00	7/18/91 15:00	7/20/11 17:00	9/1/11 16:00	8/31/11 17:00	7/20/11 16:00	7/2/11 16:00	8/28/98 16:00	8/23/11 16:00	7/10/11 18:00
2012	7/6/12 17:00	7/3/90 18:00	7/18/91 15:00	7/25/12 18:00	7/25/12 17:00	7/5/12 17:00	7/20/11 16:00	7/5/12 15:00	7/6/12 16:00	6/25/12 18:00	6/28/12 19:00
2013	7/18/13 15:00	8/27/13 15:00	7/17/13 16:00	8/30/13 18:00	9/10/13 16:00	8/31/13 16:00	8/31/13 15:00	7/19/13 16:00	6/27/13 18:00	8/7/13 17:00	8/8/13 16:00
2014	7/22/14 16:00	7/21/14 17:00	7/22/14 16:00	7/22/14 16:00	8/24/14 16:00	7/26/14 15:00	2/7/14 7:00	7/22/14 16:00	7/14/14 15:00	8/23/14 17:00	8/23/14 18:00
2015	7/28/15 16:00	8/14/15 16:00	8/14/15 18:00	7/13/15 16:00	9/2/15 16:00	7/13/15 17:00	9/3/15 15:00	8/2/15 17:00	8/7/15 18:00	8/10/15 16:00	7/30/15 16:00
2016	9/7/16 15:00	6/25/16 15:00	8/11/16 16:00	7/21/16 16:00	9/7/16 15:00	7/24/16 15:00	9/8/16 16:00	9/7/16 15:00	7/22/16 15:00	8/2/16 15:00	6/27/16 14:00
2017	7/20/17 16:00	7/6/17 17:00	9/25/17 15:00	7/20/17 17:00	9/25/17 15:00	7/20/17 16:00	9/22/17 16:00	9/26/17 15:00	7/21/17 15:00	7/20/17 16:00	7/20/17 15:00
2018	6/29/18 15:00	6/29/18 16:00	6/29/18 16:00	5/28/18 14:00	9/4/18 15:00	8/28/18 15:00	9/4/18 15:00	9/5/18 15:00	1/17/18 6:00	5/30/18 15:00	10/5/18 15:00
2019	7/19/19 14:00	7/19/19 16:00	7/10/19 15:00	7/19/19 14:00	9/16/19 15:00	7/10/19 16:00	9/12/19 15:00	7/20/19 14:00	10/2/19 16:00	8/16/19 14:00	10/2/19 16:00

Table 6-4: Time of Peak Demand for all 30 weather years

Appendix A: Comparison of Planning Year 2020 to 2021

Multiple study sensitivity analyses were performed to compute changes in the PRM target on an UCAP basis, from the 2020-2021 planning year to the 2021-2022 planning year. 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 2020 to 2021 in the waterfall chart of Figure A-1; see Section A.1 Waterfall Chart Details for an explanation.

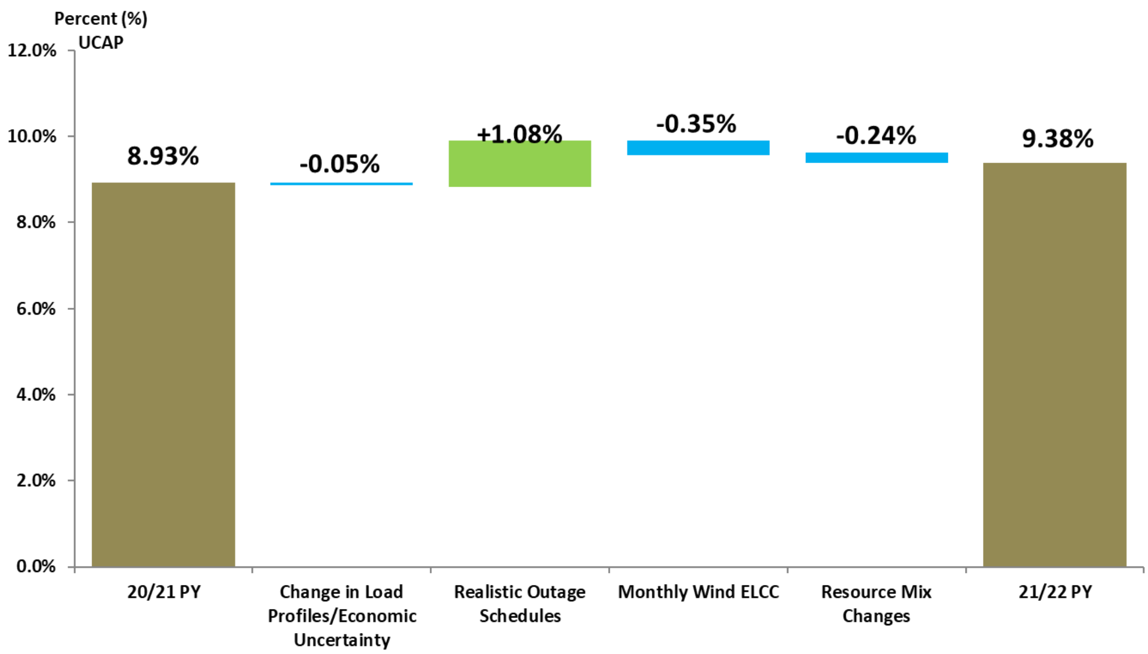


Figure A-1: Waterfall Chart of 2020 PRM UCAP to 2021 PRM UCAP

A.1 Waterfall Chart Details

A.1.1 Load

The MISO Coincident Peak Demand decreased from the 2020-2021 planning year, which was driven by the updated actual load forecasts submitted by the LSEs. The reduction was mainly driven by reduction in anticipated load growth and changes in diversity. Overall, the magnitude of changes in the load profiles and economic uncertainty was minimal and resulted in a small decrease in the PRM.

A.1.2 Units

Changes from 2020-2021 planning year values are due to changes in Generation Verification Test Capacity (GVTC); EFORd or equivalent forced outage rate demand with adjustment to exclude events outside management control (XEFORd); new units; retirements; suspensions; and changes in the resource mix. The MISO fleet weighted average forced outage rate increased from 9.24 percent to 9.36 percent from the previous study to this study. However, due to units which receive the MISO class average EFORd, which are not included in the calculation of the MISO weighted EFORd, the weighted EFORd seen by the LOLE model decreased from 9.22 percent to 9.17 percent. Additionally, the average size of the units modeled decreased by approximately 4 MW. An increase in unit outage rates and unit size will generally lead to an increase in reserve margin in order to cover the increased risk of loss of load. The realistic planned outage modeling option was used for the first time for the 2021-2022 planning year which resulted in a 1.08 percentage point increase to the PRM. This was due to planned outages overlapping unseasonably high load in shoulder periods, such as late September. The modeling of monthly wind ELCC values was also new this year. This change offset some of the shoulder risk introduced as a result of the realistic outage scheduling and caused and 0.35 percentage point decrease in the PRM.

Appendix B: 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
MIUP / 296	XEL / 600	ITCT / 219
ALTE / 694	MP / 608	SMMPA / 613
WPS / 696	DPC / 680	GRE / 615
MGE / 697		OTP / 620
UPPC / 698		ITCM / 627

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	EES-EAI / 327	OTP / 620
	SMMPA / 613	CWLP / 360	ALTE / 694
	DPC / 680	SIPC/ 361	WPS / 696
		EEI / 362	MGE / 697

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
EEI / 362	AMMO / 356	METC / 218	
	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	EES-EAI / 327	DEI / 208	SIPC / 361
AMMO / 356	AMIL / 357	NIPS / 217	XEL / 600
	EEI / 362	EES-EMI / 326	SMMPA / 613
	ITCM / 627	EES / 351	MPW / 633
	MEC / 635	CWLP / 360	DPC / 680

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		EEI / 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	Cooperative Energy / 349
	EES / 351	LAGN / 332
		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

Appendix C: 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 2021 LOLE Study Report is the annual Resource Adequacy Analysis for the peak season of June 2021 through May 2022 and beyond. Analysis of Planning Year 2021 is in Sections 5.1 and 6.1 Analysis of Future Years 2021-2030 is in Sections 5.3 and 6.1
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 4.5 of this report outlines the utilization of LOLE in the reserve margin determination. "These metrics were determined by a probabilistic LOLE analysis such that the LOLE for the planning year was one day in 10 years, or 0.1 day per year."
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 4.3 of this report. "Direct Control Load Management and Interruptible Demand types of demand response were explicitly included in the LOLE model as resources. These demand resources are implemented in the LOLE simulation before accumulating LOLE or shedding of firm load."
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 4.5.1 of this report. "The minimum amount of capacity above the 50/50 net internal MISO Coincident Peak Demand required to meet the reliability criteria was used to establish the PRM values."
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 5.1 and 6.1, a full analysis was performed for planning year 2021.
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.	Sections 5.3 and 6.1 show a full analysis was performed for future planning years 2024 and 2026.
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 4.3 of this report: "The average monthly loads of the predicted load shapes were adjusted to match each LRZ's Module E 50/50 monthly zonal peak load forecasts for each study year." Load Forecast Uncertainty – A detailed explanation of the weather and economic uncertainties are given in Sections 4.3.1 and 4.3.2. Load Diversity/Seasonal Load Variations — In Section 4.3 of this report: "The 2021-2022 LOLE analysis used a load training process with neural net software to create a neural-net relationship between historical weather and load data. This relationship was then applied to 30 years of hourly historical weather data to create 30 different load shapes for each LRZ in order to capture both load diversity and seasonal variations." Demand Modeling Assumptions/Curtailable and Interruptible Demand — All Load Modifying Resources must first meet registration requirements through Module E. As stated in Section 4.2.7: "Each demand response program was modeled individually with a monthly capacity and was limited to the number of times each program can be called upon as well as limited by duration."
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 4.2 details how historic performance data and seasonal ratings are gathered, and includes discussion of future units and the modeling assumptions for intermittent capacity resources. A more detailed explanation of firm capacity purchases and sales is in Section 4.4.
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 3 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 3.2.3.
R1.3.4 Assistance from other interconnected systems including multi-area assessment considering Transmission limitations into the study area.	Section 4.4 provides the analysis on the treatment of external support assistance and limitations.

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 4.2. The use of demand response programs are mentioned in Section 4.2. The effects of resource outage characteristics on the reserve margin are outlined in Section 4.5.2 by examining the difference between PRM ICAP and PRM UCAP values.
R1.5 Consider Transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included	Transmission maintenance schedules were not included in the analysis of the transmission system due to the limited availability of reliable long-term maintenance schedules and minimal impact to the results of the analysis. However, Section 3 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 5 and 6.
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 5 and 6.
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 5 and 6, the peak load and estimated amount of resources for planning years 2021, 2024, and 2026 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.	Section 5.3 and Table 5-4 shows the three calculated years, and in-between years estimated by interpolation. Estimated transmission limitations may be determined through a review of the 2021 LOLE study transfer analysis shown in Section 3 of this report, along with the results from previous LOLE studies.
R2.2 This documentation shall include the Planning Reserve margin calculated per requirement R1.1 for each of the three years in the analysis.	Section 5.3 and Table 5-4 shows the three calculated years underlined.
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 2021 LOLE Study Report documentation is posted on November 1 prior to the 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 5 and 6, the difference between the needed amount and the projected planning reserves for planning years 2021, 2024, and 2026 are shown the adjustments to ICAP and UCAP in Table 5-1, Table 5-3, Table 6-1, Table 6-2, and Table 6-3.

Appendix D: 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 Corp.
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
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

Appendix E: Future LRR Analysis Using Realistically Optimized Outage Scheduling

As described in section 2.1, SERVM has the ability to create a unique planned outage schedule optimized for each load shape (perfectly optimized) or a single outage schedule optimized based on the average of the 30 load shapes (realistically optimized). In MISO's initial 2021-22 PY LOLE analysis the realistic planned outage modeling approach was used for both the PRM and LRR analyses. Recognizing the magnitude of changes in LRRs as shown in table E-1 and need for a proper transition, MISO reverted to the perfectly optimized outage method for the LRR analysis and revised the initial LRR values to give stakeholders ample time to adjust to the changes. Going forward, MISO plans to work with stakeholders to implement the realistically optimized planned outage scheduling methodology for both PRM and LRR analysis as part of the 2022-23 PY LOLE study, recognizing that some modifications may need to be made to the methodology.

LRZ	Revised LRR using perfectly optimized outage methodology	Preliminary LRR using realistically optimized outage methodology
1	114.7%	116.4%
2	114.5%	118.0%
3	117.1%	117.2%
4	126.9%	127.9%
5	125.0%	125.3%
6	114.7%	118.0%
7	121.2%	129.2%
8	136.1%	138.2%
9	115.5%	124.0%
10	152.7%	155.2%

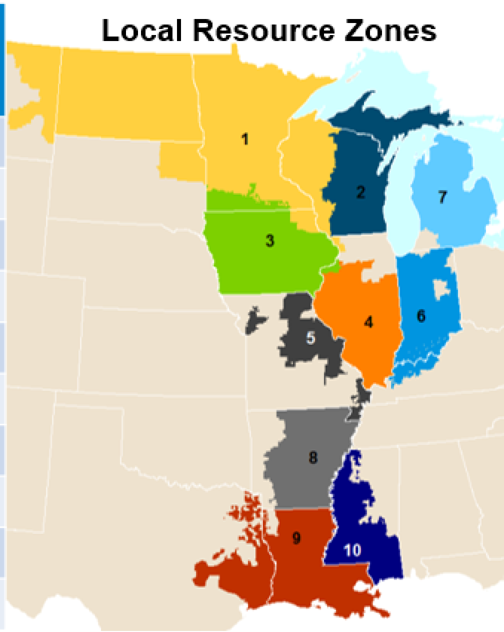


Figure E-1: LRR results comparison using different planned outage scheduling approaches