2025 State of the Market Report for the MISO Electricity Markets

Prepared By:

POTOMAC ECONOMICS

**Independent Market Monitor
for the Midcontinent ISO**

June 2026

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Guide to Acronyms

AAR	Ambient Adjusted Rating
AMP	Automated Mitigation Procedure
ARC	Aggregator of Retail Customers
ARR	Auction Revenue Rights
ASM	Ancillary Services Market
BCA	Broad Constrained Area
BTMG	Behind-The-Meter Generation
CDD	Cooling Degree Day
CONE	Cost of New Entry
CROW	Control Room Operating Window
CTS	Coordinated Transaction Scheduling
DA	Day-Ahead
DAMAP	Day-Ahead Margin Assurance Pmt.
DIR	Dispatchable Intermittent Resource
DR	Demand Response
DRR	Demand Response Resource
ECF	Excess Congestion Fund
EDR	Emergency Demand Response
EEA	Emergency Energy Alert
ELMP	Extended LMP
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Reg. Commission
FFE	Firm Flow Entitlement
FRAC	Fwd. Reliability Assessment Commitment
FSR	Fast-Start Resource
FTR	Financial Transmission Right
GSF	Generation Shift Factor
HDD	Heating Degree Day
HHI	Herfindahl-Hirschman Index
ICAP	Installed Capacity
IESO	Ontario Electricity System Operator
IMM	Independent Market Monitor
ISO-NE	ISO New England, Inc.
JOA	Joint Operating Agreement
LAC	Look-Ahead Commitment
LBA	Local Balancing Area
LMP	Locational Marginal Price
LMR	Load-Modifying Resource
LRZ	Local Resource Zone
LSE	Load-Serving Entity
M2M	Market-to-Market
MCC	Marginal Congestion Component
MCP	Market Clearing Price
MISO	Midcontinent Independent Sys. Operator
MMBtu	Million British thermal units
MSC	MISO Market Subcommittee
MVL	Marginal Value Limit
MW	Megawatt
MWh	Megawatt-hour
NCA	Narrow Constrained Area
NERC	North American Electric Reliability Corp.
NSI	Net Scheduled Interchange
NYISO	New York Independent System Operator
ORDC	Operating Reserve Demand Curve
PJM	PJM Interconnection, Inc.
PRA	Planning Resource Auction
PRMR	Planning Reserve Margin Requirement
PVMWP	Price Volatility Make-Whole Payment
RDT	Regional Directional Transfer
RPE	Reserve Procurement Enhancement
RSG	Revenue Sufficiency Guarantee
RT	Real-Time
RTO	Regional Transmission Organization
RTORSGP	Real-Time Offer Revenue Sufficiency Guarantee Pmt.
SMP	System Marginal Price
SOM	State of the Market
SPP	Southwest Power Pool
SSR	System Support Resource
STLF	Short-Term Load Forecast
STR	Short Term Reserves
TCDC	Transmission Constraint Demand Curve
TLR	Transmission Line Loading Relief
TO	Transmission Owner
TVA	Tennessee Valley Authority
UCAP	Unforced Capacity
UDS	Unit Dispatch System
VLR	Voltage and Local Reliability
VOLL	Value of Lost Load
WUMS	Wisconsin-Upper Michigan System

Executive Summary

As the Independent Market Monitor (IMM) for the Midcontinent Independent System Operator (MISO), we evaluate the competitive performance and efficiency of MISO's wholesale electricity markets. The scope of our work in this capacity includes monitoring for attempts to exercise market power or manipulate the markets, identifying market design flaws or inefficiencies, and recommending improvements to market design and operating procedures. This Executive Summary to the *2025 State of the Market Report* provides an overview of our assessment of the performance of the markets and summarizes our recommendations.

MISO operates competitive wholesale electricity markets in the Midcontinent region that extends geographically from Montana in the west, to Michigan in the east, and to Louisiana in the south. The MISO geographic footprint is shown to the right, with MISO South in blue and MISO Midwest in green.

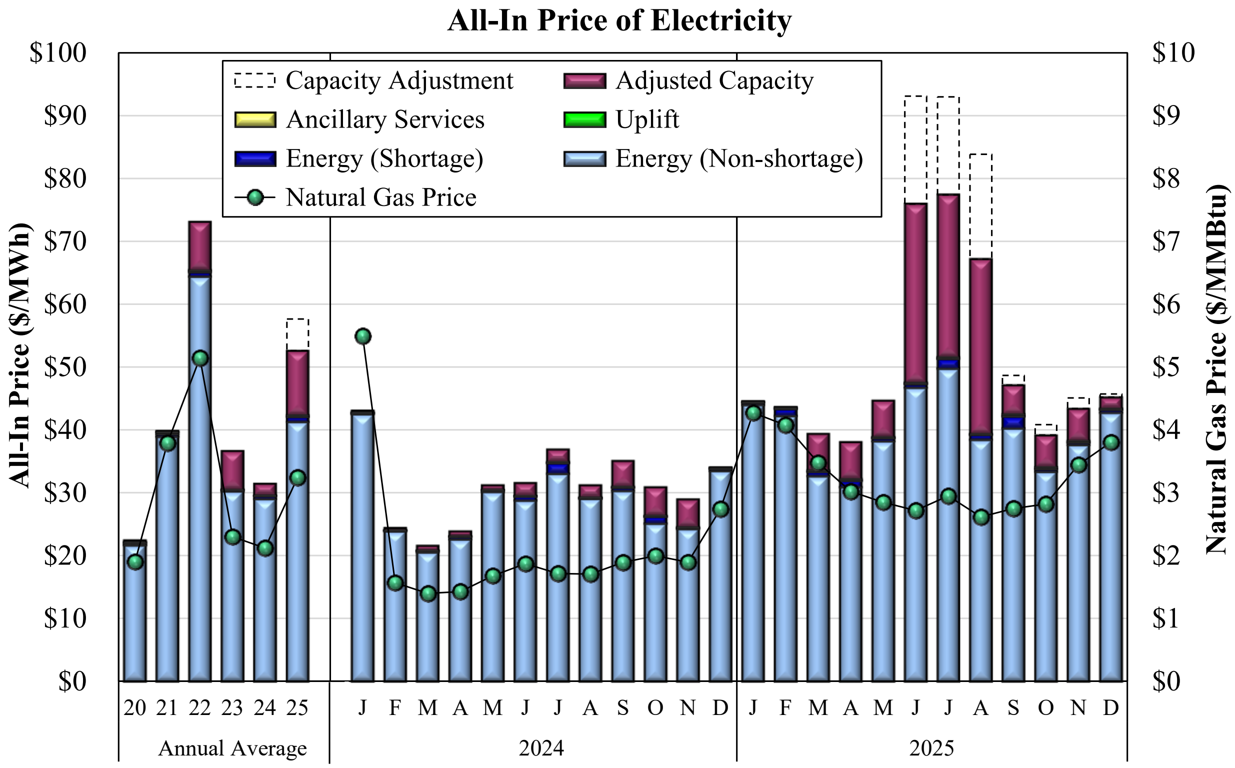
MISO launched its markets for energy and financial transmission rights (FTRs) in 2005, the ancillary services market in 2009, and the capacity market in 2013. These markets coordinate the planning, commitment, and dispatch of generation to ensure that resources are meeting system demand reliably at the lowest cost.

Additionally, the MISO markets establish prices that reflect the marginal value of energy at each location on the network (i.e., locational marginal prices or LMPs). These prices facilitate efficient actions by participants in the short term (e.g., to make resources available and to schedule imports and exports) and support long-term decisions (e.g., investment, retirement, and maintenance). The remainder of this Executive Summary provides an overview of market outcomes, a discussion of key market issues, and a list of recommended improvements.

Summary of Market Outcomes and Competitive Performance

MISO's energy and ancillary services markets generally performed competitively in 2025. Multiple factors affected market outcomes, including changes in the load, the resource mix, and fuel prices. The figure below shows a 67 percent increase in the all-in price throughout MISO, averaging roughly $53 per MWh. The following factors contributed to this increase:

- A 58 percent increase in the Henry Hub natural gas price;
- More frequent shortages around sunset;
- The introduction of a sloped capacity demand curve; and
- A three percent increase in average load in 2025 to around 78 GW.



Frequent transmission congestion often caused prices to diverge throughout MISO. The value of real-time congestion rose by about 23 percent in 2025 to $2.2 billion, largely because of:

- Higher natural gas prices;
- A confluence of transmission and generation outages in the spring in MISO South; and
- Higher wind-driven congestion in the Midwest, which rose by 9 percent from 2024.

Real-time congestion was higher than optimal because several key issues continued to hinder congestion management, including:

- Conservative static ratings by most transmission owners;
- Issues defining and coordinating market-to-market and other external constraints;
- Frequent transmission derates by MISO operators;
- Reliance on manual dispatch instructions in cases where the real-time dispatch model can optimally dispatch and price the congestion; and
- MISO's limited authority to coordinate outages.

To address these concerns, we continue to recommend a number of improvements to lower the cost of managing congestion on MISO's system. These improvements promise some of the largest short-term benefits of any of the recommendations we make in this report.

Significant Events in 2025

MISO experienced several challenging weather and transmission-related events in 2025.

- In January, MISO operators maintained reliability during Winter Storm Enzo without incurring significant costs, in large part by increasing day-ahead and real-time STR requirements. Uplift totaled just $2.6 million, down more than 90 percent from Winter Storms Uri and Elliott and two-thirds from Winter Storm Heather.
- In the spring in MISO South, storms and planned and forced transmission and generator outages caused two load-shed events. We find that MISO's load shedding instructions helped avoid the risk of broader reliability issues, including cascading outages. We recommended improvements to MISO's processes that should result in better visibility into and performance by emergency-only resources.
- In June and July, hotter-than-usual temperatures across much of the Eastern Interconnection prompted multiple Local Balancing Authorities, including MISO, to declare emergencies or other capacity sufficiency declarations.
  - While PJM declared emergencies on 10 days, MISO entered a Maximum Generation Event on just one day, June 23.
  - MISO's shortage pricing and emergency pricing throughout this period allowed it to set prices that prompted high levels of imports that played a key role in maintaining sufficient supply during these conditions.
- In September, a major transmission outage in MISO South prompted MISO operators to declare a Transmission Emergency and take other steps, including manual redispatches, to prevent load shed. While MISO maintained reliability, we find that a 10-step Transmission Constraint Demand Curve (TCDC) would have allowed the market to manage the emergency at a much lower cost.
- In September, we identified a software issue related to the TLR process, prompting MISO to use its Continuing Error provisions to reprice in 19 hours. We found that the repricing caused prices to not reflect accurately reserve shortages that occurred during the event and harmed a number of participants that responded to the original prices. Our report includes a recommendation to address the adverse effects of these types of events.

In general, MISO performed well during these events, maintained reliability and avoided costly out-of-market actions in most cases. We discuss and evaluate these events in Section II.E.

Competitive Performance

Outcomes in the MISO markets continue to show a consistent correlation between energy and natural gas prices that is expected in a well-functioning, competitive market. Gas-fired resources are most often the marginal source of supply, and fuel costs constitute the vast majority of most resources' marginal costs. Competition provides a powerful incentive to offer resources at prices reflecting their marginal costs. We evaluate the competitive performance of the markets by assessing the suppliers' conduct using the following two empirical measures of competitiveness:

- A "price-cost mark-up" compares simulated energy prices based on actual offers to energy prices based on competitive offer prices. The price-cost mark-up was very small at negative one percent, indicating the markets were highly competitive.
- The "output gap" is a measure of potential economic withholding. It remained very low, averaging 0.08 percent of load, which does not raise concerns.

These results, as well as the results of our ongoing monitoring, confirm that the MISO markets are delivering the benefits of robust competition to MISO's customers.

Market Design Improvements

Although MISO's markets continue to perform competitively, we have identified a number of key areas that could be improved as MISO's generating fleet evolves in the coming years. Hence, this report provides several recommendations, six of which are new this year. MISO has continued to respond to past recommendations and implemented several key changes recently:

Capacity Market

- MISO implemented a Reliability-Based Demand Curve (RBDC) in 2025 that we had recommended for more than a decade. The RBDC establishes capacity requirements that correspond to the marginal reliability value that capacity provides. This has already fundamentally improved capacity pricing and long-term price signals, as well as ensuring that MISO procures an efficient level of capacity.
- MISO developed marginal capacity accreditation to be implemented in the 2028–2029 Planning Year. This was a high-priority recommendation because it is essential to facilitate efficient investment and retirement decisions in resources that provide very different reliability contributions to the system.
- MISO terminated eligibility for energy efficiency to participate in the capacity market.

Energy Market

- MISO improved its shortage pricing by reforming its 10-minute reserve demand curves to reflect a value of lost load of $35,000 per MWh, capped at $10,000 per MWh for deep shortages. This was another high-priority recommendation because it provides essential performance incentives and revenues to the flexible resources needed to maintain reliability amid growing operational uncertainties.
- MISO implemented an Uninstructed Deviation Enhancement (UDE) dispatch flag to clarify when intermittent resources are loading a transmission constraint and must follow dispatch instructions. We recommended penalty provisions for dispatch deviations when

the UDE flag is active to align incentives with the UDE flag, and MISO filed associated tariff changes in February 2026.

Market Operations

- MISO transitioned to a new logging system and introduced new measures to ensure operators document key decisions. MISO operators have implemented commitment improvements that have reduced real-time RSG costs by more than $100 million per year.

These changes have improved the performance of the markets and the operation of the system. We discuss these improvements and outstanding recommendations throughout this report.

Future Market Needs

The MISO system is changing rapidly as its resource fleet transitions and new technologies enter the market. These changes require MISO to adapt to new operational and planning needs. In addition, the long period of low load growth appears to be ending, and MISO now faces compound annual load growth of three to five percent over the next five years, which will steadily increase capacity needs.

Fortunately, MISO's markets are robust and well-suited to meet these challenges without fundamental market changes. A number of the design improvements described above that MISO implemented in 2025 are essential changes. We discuss below some additional key incremental improvements that will be needed as this transition occurs.

Large Loads. MISO now faces the rapid entry of new large loads, particularly data centers, and resulting transmission issues. Some of these large loads may need to be served on a non-firm basis, as the MISO Transmission Expansion Plan (MTEP) catches up to these greater transmission needs. In this report, we discuss five principles that we have urged MISO's Large Load Working Group to consider, so market design, the interconnection process, and cost allocation practices reflect the operational and reliability impacts of these loads.

Over the past decade, the penetration of renewable resources has steadily increased as baseload coal resources have retired. This trend is likely to accelerate as large quantities of solar, battery storage resources, and hybrid resources now accompany new wind resources in the interconnection queue. The most significant supply-side challenges of renewable integration include:

- *Wind*: As wind generation increases, the volatility of its output grows as do the errors in forecasting the wind output.
- *Solar*: Solar resources are forecasted to grow more rapidly than any other resource type in the next 20 years. This will lead to significant changes in the system's ramping needs for its dispatchable resources, particularly in the evening as the sun sets.

- *Energy Storage*: MISO is working to enable Energy Storage Resources (ESRs) to participate in the markets while recognizing their unique characteristics. Falling costs and rising price volatility should cause ESRs to be increasingly economic in the future.

As discussed above, the market reforms MISO has implemented in recent years are essential and will help the markets facilitate investment in new resources and retention of existing resources needed to satisfy the needs of the system. In addition, Section III.C recommends other important improvements to account for the rising system uncertainty and improve the utilization of the network as transmission flows become more volatile. The key recommended improvements include:

- Introduce an uncertainty product that reflects MISO's need to commit resources to maintain sufficient supply in real time to manage uncertainty;
- Implement a look-ahead dispatch and commitment model in the real-time market; and
- Introduce new processes to optimize transmission operations and increase transmission utilization.

Energy Market Performance and Operations

Day-Ahead Market Performance

The day-ahead market is critical because it coordinates most resource commitments and is the basis for almost all energy and congestion settlements with participants. Day-ahead market performance can be judged by the extent to which its prices converge with real-time prices. This facilitates efficient resource commitments that satisfy the system's operational needs. In 2025:

- The difference between day-ahead and real-time prices, including day-ahead and real-time uplift charges, was good at roughly two percent.
- However, episodes of congestion caused by generation and transmission line outages led to transitory periods of divergence at various locations.

Virtual transactions provided essential liquidity and improved the convergence of day-ahead and real-time energy prices. Cleared transactions increased by five percent, rising comparably in both subregions. Our evaluation of virtual transactions revealed:

- Financial participants submit offers more price-sensitively, which provides liquidity in the day-ahead market.
- 57 percent of virtual transactions improved price convergence and economic efficiency.
- Participants continued to submit price-insensitive matching virtual supply and demand transactions to arbitrage congestion differences. The virtual spread product we continue to recommend would facilitate this arbitrage in a more efficient, lower-risk manner.

- Only 2.6 percent of transactions were price-insensitive and caused congestion divergence between the day-ahead and real-time markets, raising no manipulation concerns in 2025.

Real-Time Market Performance and Price Formation

The performance of the real-time market is crucial because it governs the dispatch of MISO's resources. The real-time market sends economic signals that facilitate scheduling in the day-ahead market and longer-term investment and retirement decisions. Efficient price signals during shortages and tight operating conditions provide incentives for resources to be flexible and perform well. Shortage pricing will be increasingly important as intermittent resources continue to grow. Shortage pricing also reduces resources' reliance on revenues from the capacity market to maintain resource adequacy. Hence, MISO's recent ORDC reforms are essential.

In addition to shortage pricing, its ELMP pricing model plays a key role in achieving efficient price formation by allowing online fast-start peaking resources (FSRs) and emergency supply to set prices when they are economic. Section IV.C of this report shows that the average effect of ELMP on real-time energy prices was $1.58 per MWh in 2025, higher than in prior years because of higher energy prices and more frequent emergency pricing in June and July.

MISO's emergency pricing is generally efficient and effective by allowing emergency capacity and actions to set prices during emergencies. However, pricing when large quantities of LMRs are deployed can be substantially overstated because the ELMP model cannot ramp other units up quickly enough to replace them. To address this concern, we recommend MISO reintroduce LMR curtailments as an STR demand instead of energy demand. This will allow the ELMP model to more accurately determine whether LMRs are needed and should set prices.

Uplift Costs in the Day-Ahead and Real-Time Markets

Evaluating uplift costs is important because customers have difficulty forecasting and hedging them, and they generally reveal where market prices do not fully capture the cost of system requirements. Most uplift costs result from guarantee payments to participants. MISO employs two primary forms of guarantee payments to ensure resources cover their as-offered costs and to incentivize them to be available and flexible:

- Revenue Sufficiency Guarantee (RSG) payments ensure that a resource's market revenue is at least equal to its as-offered costs over its commitment period; and
- Price Volatility Make-Whole Payments (PVMWP) ensure suppliers will not be financially harmed by following the five-minute dispatch signals.

Day-ahead RSG. These payments rose by 55 percent to $47.8 million, generally in line with the increase in gas prices. Units in MISO South received 58 percent of day-ahead capacity-related RSG payments and 85 percent of day-ahead voltage RSG payments.

Real-time RSG. These payments rose 58 percent in 2025, driven by higher fuel costs and a single expensive unit repeatedly committed in MISO South to manage congestion in the fall. Despite these increases, MISO has significantly improved its commitment processes since 2021.

PVMWPs. These costs increased by about 2.5 percent from 2024. An increase in ancillary services shortages caused more frequent price spikes in 2025, causing DAMAP to generators during ancillary services shortages to more than double from 2024.

Real-Time Generator Performance

We monitor and evaluate the poor performance of some generators in following MISO's dispatch instructions on an ongoing basis. Dragging by conventional resources was roughly 200 MW in the worst 10 percent of hours in 2025, slightly higher than in 2024. We focus on improving incentives for generator performance because it will be increasingly important, particularly during ramp hours, as the sun sets and solar output drops sharply.

Renewable resources present distinct dispatch challenges because of forecast errors that can be large and because their owners are at times economically indifferent to following dispatch instructions. Renewables' divergences from dispatch can result in severe transmission violations and compel MISO to use out-of-market actions.

To address this concern and improve dispatch incentives for all resources, we proposed a deviation penalty based on the marginal congestion component (MCC) of the resource's LMP that is described in Section IV.E. An MCC-based penalty is appropriate because it reflects the congestion value of the deviation volumes and scales with the severity of congestion. MISO filed tariff changes in February 2026 to implement this recommendation.

Wind and Solar Generation and Forecasting

Installed wind capacity accounted for 28 GW of MISO's installed capacity, while solar accounted for 18 GW, by the end of 2025, and both have continued to grow in 2026. Wind and solar produced about 19 percent of all energy in MISO in 2025. We expect solar growth to outpace wind additions in the future, though capacity for both technologies will grow. The report identifies operational and market issues associated with the growth of wind and solar resources.

Day-Ahead Scheduling. Wind suppliers generally under-schedule their output in the day-ahead market, averaging roughly 1,300 MW less than their real-time output. This may be attributed to the suppliers' contracts and the financial risk related to RSG allocations to over-scheduled wind. Under-scheduling can undermine price convergence and resource commitments, which is partly addressed by virtual suppliers that sell day-ahead energy in place of the wind suppliers.

Real-Time Wind and Solar Forecasting. One of MISO's operational challenges is the large dispatch deviations that can be caused by wind and solar forecast errors. A renewable unit's forecast sets that unit's dispatch maximum and, because renewable offer prices are low, the forecast also tends to determine the dispatch level. If the real-time forecast is inaccurate, the dispatch does not accurately model flows on transmission constraints affected by wind and solar resources, making it more difficult to manage congestion and avoid transmission violations. MISO has improved these forecasts in recent years, including by improving the timeliness of the wind forecasts by bringing them in-house. MISO's solar forecasts are not as timely and the forecast errors have been larger, which has raised concerns during the evening ramp hours. We recommend that MISO make similar changes to the solar forecasting process to make it more timely and accurate.

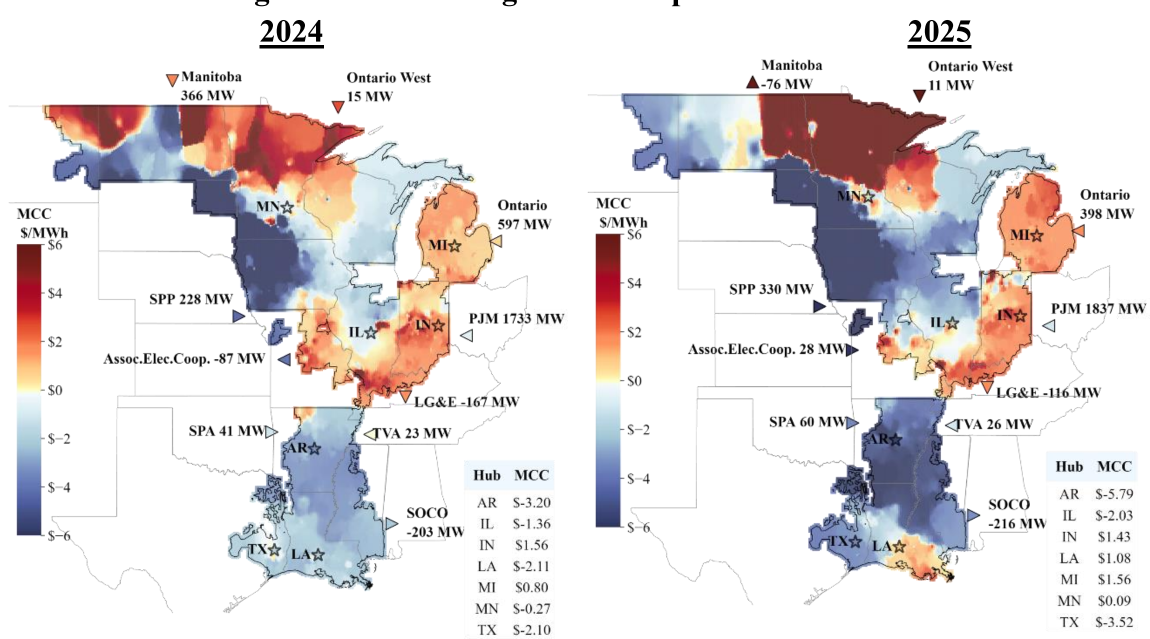
Transmission Congestion and FTR Markets

Transmission congestion costs arise on the MISO network when a higher-cost resource is dispatched in place of lower-cost ones to avoid overloading transmission constraints. These congestion costs arise in both the day-ahead and real-time markets. These costs are reflected in MISO's location-specific energy prices, which represent the marginal costs of serving load at each location given the marginal energy costs, network congestion, and losses. Because most energy is settled in the day-ahead market, most congestion costs are collected in this market.

Congestion Costs in 2025

The nominal value of real-time congestion rose by 22.5 percent in 2025 to $2.2 billion, largely because of higher natural gas prices. The maps below show the year-over-year changes in congestion patterns from 2024 to 2025.

Average Real-Time Congestion Components in MISO's LMPs



Day-ahead congestion similarly increased by 27 percent to $1.6 billion in 2025. MISO does not collect revenues associated with the full value of real-time congestion because entities that do not settle with MISO cause a large amount of "loop flows." MISO also grants flow entitlements on its system to SPP and PJM, so they do not pay for congestion up to their entitlement levels. The increase in both day-ahead and real-time congestion is consistent with higher gas prices in 2025.

Day-ahead congestion revenues fund MISO's Financial Transmission Rights (FTRs). FTRs represent the economic property rights associated with the transmission system and serve as a hedge against day-ahead congestion costs. Efficient FTR markets set prices that reflect accurate expectations of day-ahead congestion. However, these markets have not always performed well, particularly in the Multi-Period Monthly Auctions (MPMAs) and monthly auctions. We have evaluated and identified two principal factors affecting FTR market performance:

- The accuracy of the network topology, which depends largely on the completeness of MISO's understanding of upcoming transmission outages; and
- The liquidity of the FTR auctions.

Outage Reporting. Transmission owners must schedule outages in MISO's CROW system 12 months in advance. However, some transmission owners have not complied with this requirement, and some outages are not known far in advance. As a result, the outages reflected in the annual FTR process are much less complete than those reflected in the timelier auctions. Additionally, MISO must be conservative, so it assumes that an outage scheduled for longer than five days will occur over the entire season. Hence, network modeling is much more accurate in the monthly and seasonal timeframes because most planned outages are known by then.

Participation and Liquidity. Although network topology is much more accurate in the MPMA and monthly auction timeframes, these markets tend to perform more poorly at setting prices that reflect realized congestion in the day-ahead market over time, indicating that these auctions are not sufficiently liquid. Annual FTR auction prices align more closely with realized congestion than monthly auction prices because transmission customers participate in the annual auction. MISO currently allocates ARRs only once, before the Annual FTR Auction.

Selling the bulk of the transmission capability in the Annual Auction has led to FTR shortfalls because many transmission outages are not known or reported before the Annual Auction. This causes some constraints to be oversold, resulting in funding shortfalls in the day-ahead market.

To reduce the FTR shortfalls and facilitate transmission customer participation and liquidity in the seasonal and monthly FTR auctions, we recommend that MISO:

- Make a smaller share of transmission capacity (e.g., one third) available for ARR allocation and sale in the Annual FTR Auction, down from 90 percent currently;
- Release additional transmission capacity to be allocated as ARRs and sold as FTRs in seasonal and monthly FTR auctions (e.g., half of the remaining capacity in each); and

- Modify the ARR allocation process to better align with customers' current use of the system and to facilitate allocation of capability that would otherwise remain unallocated under the current generation-to-load nomination process.

By withholding more capacity for the seasonal or monthly auctions, these markets will perform better, and customers will likely receive a higher share of the system's full value. This will also greatly reduce the likelihood of overselling constraints in the annual auction, which would compel MISO to purchase counter-flow FTRs.

Additionally, the recent influx of large new data center loads for cloud computing and cryptocurrency mining has sharply increased the risk that load distribution will change significantly during the 16-month span from completion of the ARR studies to the end of the FTR year. In this report, we propose several options to mitigate this risk.

Congestion Management Concerns and Potential Improvements

Although overall there have been improvements in MISO's congestion management processes, we remain concerned about a number of issues that undermine the efficiency of MISO's management of transmission congestion. Given the vast costs incurred annually to manage congestion, initiatives to improve congestion management are likely to be among the most beneficial. Hence, we encourage MISO to assign a high priority to addressing these issues.

Outage Coordination. Transmission and generation outages often occur simultaneously and affect the same constraints. Multiple simultaneous generation outages contributed to $625 million in real-time congestion costs in 2025 – 28 percent of real-time congestion costs. We continue to recommend that MISO explore improvements to its coordination of transmission and generation outages, including expanding its outage approval authority to include some form of economic criteria for approving and rescheduling planned outages.

Understated Transmission Ratings. Most transmission owners (TOs) still do not actively adjust their facility ratings to reflect ambient temperatures or provide emergency ratings for contingent constraints (when the actual flow would temporarily approach this rating only after the contingency) because they have little economic incentive to do so. In December 2021, FERC issued Order 881, which requires TOs to provide AARs and emergency ratings based on facility-specific evaluations by mid-2025. On March 17, 2025, MISO filed a motion to extend the compliance deadline to the end of 2028 because of software delays. However, the real-time element of Order 881 could be fully satisfied over the next year, and the vast majority of AAR benefits will accrue in the real-time market. Our analysis shows that AARs could have avoided more than half a billion dollars in congestion costs in 2024 and 2025. Therefore, we encourage MISO to continue to work with its TOs to implement real-time AARs as soon as possible.

Transmission Reconfiguration. It can often be highly economic to alter the configuration of the network (e.g., opening a breaker) to reduce flows on a severely constrained transmission facility. Reliability Coordinators do this regularly to address congestion-related reliability concerns, but seldom to reduce congestion and resulting costs. In 2022, MISO created the Reconfiguration for Congestion Cost Task Team to evaluate and implement reconfiguration requests. In 2025, it implemented very few reconfiguration requests. MISO has no near-term plans to develop internal tools to suggest economic reconfiguration options, nor has it developed a process to ensure timely evaluations of alternatives. We recommend that MISO pursue these enhancements.

Generator Decommitments. Based on an analysis of the value of decommitting resources that are causing congestion, we recommend MISO use the Look-Ahead Commitment (LAC) and modify its procedures to identify and decommit resources.

RDT Pricing. We recommend that MISO modify the RDT TCDC by adding lower-valued steps starting at 80 percent of the contract limit and by raising the energy plus STR limit to align with the highest penalty step on the TCDC. These demand curve adjustments will increase RDT utilization when subregional transfers are highly valuable and reduce the burden on MISO operators, who must constantly monitor and adjust the RDT limit in the real-time market.

Market-to-Market Coordination

There are many MISO constraints that are greatly affected by generation in PJM and SPP, and likewise constraints in these areas that are affected by MISO generation. Therefore, MISO coordinates congestion management on these constraints through the market-to-market (M2M) process with SPP and PJM. Real-time congestion on MISO's M2M constraints totaled $808.4 million in 2025, which was around 36 percent of all real-time congestion in MISO.

It is essential that M2M coordination operate as effectively as possible, and we evaluate the M2M process by tracking the convergence of the shadow prices of M2M constraints. When the process is working well, the "non-monitoring RTO" (NMRTO) will continue to provide additional relief until the marginal cost of its relief (its shadow price) is equal to the shadow price of the "monitoring RTO" (MRTO) responsible for managing the constraint.

M2M coordination has generally contributed to shadow price convergence over time and lowered the costs of managing congestion. However, we also find that coordination could be improved with the following key changes and deliver substantial additional savings.

- *Relief request software*. On some constraints, shadow prices fail to converge because the current relief request software does not consider shadow price differences between the RTOs. When the NMRTO's shadow price remains much lower, the requested relief should increase to lower congestion costs and accelerate convergence. At other times, the software can request too much relief, causing constraints to bind and unbind in subsequent intervals, a pattern called "oscillation." We have recommended that MISO base relief requests on the RTOs' respective shadow prices and implement an automated means to control constraint oscillation.

- *M2M tests*. M2M constraints are identified when the NMRTO places substantial market flows on the constraint or has at least one generator with a GSF greater than five percent on the constraint. The latter has frequently caused constraints to be defined as M2M with extremely small benefits. Hence, we recommend that MISO replace the five-percent test with a test based on the NMRTO's relief capability on the constraint.
- *Day-Ahead Coordination*. The convergence of M2M constraints is poor in the day-ahead market. MISO and PJM implemented a process to coordinate and exchange firm flow entitlements (FFEs) in the day-ahead market, but they do not actively use it. We recommend that MISO continue working with SPP and PJM to implement FFE exchanges on M2M constraints.

Operator Actions

MISO operators are responsible for maintaining reliability, which can require operator actions. These actions can have sizable impacts on market outcomes and generate significant costs. Many of these actions are taken to manage congestion and address constraint violations, including:

- Derating transmission facilities through "limit control" adjustments. These incidents should be minimized because their cost can be substantial ($137 million in 2025); and
- Manual re-dispatch (MRD) of resources or capping their output. The use of MRDs and caps declined in 2025, reflecting MISO's success in relying more heavily on the dispatch software.

We continued to work collaboratively with MISO in 2025 to improve procedures governing these actions. This collaboration has resulted in significant improvement. MISO also is working on other changes to improve the market's ability to manage congestion, which should also reduce the need for these actions.

Long-Term Economic Signals and Resource Adequacy

Capacity Levels and Summer Capacity Margins

Capacity levels have fallen in recent years because accelerating retirements of baseload resources have been only partially offset by renewable additions, although additions outpaced retirements in 2025. In 2025, MISO experienced the following additions and retirements:

- 1.1 GW of resources retired or suspended operations, which were mostly coal and gas steam resources. However, 1.6 GW of additional of coal-fired resources would have retired, but DOE issued emergency orders in June and December 2025 directing them to remain online.
- 3.1 GW of new unforced capacity entered MISO in 2025. This included 1.3 GW from solar resources, bringing MISO's nameplate solar capacity to approximately 18 GW by the end of 2025. The other additions include a new 650 MW combined-cycle unit in the

South, 400 MW of gas replacement projects in the Midwest, and 370 MW of new battery Energy Storage Resources (ESRs).

Planning Resource Auction Results

MISO responded to one of our longstanding recommendations by implementing downward-sloping RBDCs in the 2025–2026 PRA. In this auction, across the four seasons, market clearing prices averaged nearly $215 per MW-day, ranging from $33.20 per MW-day in winter to $666.50 per MW-day in summer. These prices reflect the prevailing capacity margins; the PRA cleared with a modest 1.7 percent surplus in summer.

Unfortunately, after posting the PRA results, MISO discovered a modeling error in its Loss of Load Expectation (LOLE) assumptions that affected the RBDC and concluded that it needed to resettle the capacity auction in August 2025. The resettlement was harmful to the integrity of the competitive markets and was inconsistent with the information that participants used to make resource and contracting decisions.

In the 2026–2027 PRA, across the four seasons, market clearing prices averaged nearly $126 per MW-day, ranging from $7.61 per MW-day in the spring to $424.30 per MW-day in the summer. These clearing prices were inefficiently low because existing solar resources were over-accredited. Currently, MISO bases the existing solar accreditation on their output from 2 pm to 5 pm even though most reliability risk has shifted to evening hours. This resulted in an average accreditation for existing solar resources of nearly 70 percent, more than double the expected accreditation levels under the marginal Direct Loss of Load (DLOL) framework MISO will implement in 2028.

We recommend solar accreditation be based on evening hours, such as 4 pm to 7 pm, to yield more accurate accreditations in the 2027–2028 PRA. Such a change would have increased the prevailing capacity prices in the most recent PRA by roughly 50 percent and would more efficiently reflect the prevailing capacity margins in MISO.

Long-Term Signals: Net Revenues

Market prices should provide economic signals that govern participants’ long-run investment, retirement, and maintenance decisions. These signals can be measured by the “net revenues” generators receive in excess of their production costs. We evaluate these signals by estimating the net revenues that different types of new resources would have received in 2025.

- Net revenues increased markedly for combustion-turbine (CT) and combined-cycle (CC) units in all zones in 2025, driven by higher energy and ancillary services prices, higher capacity revenues under the new RBDC, and more frequent summer hot weather events.
- In most regions, investment signals indicate that building new resources would be economic, with the exception of the South region outside of Louisiana.

Capacity Market Design Improvements

Although adopting RBDCs and improving capacity accreditation via the DLOL method have been the most important design improvements, we recommend that MISO consider the following additional improvements to provide better incentives to MISO's suppliers in the long term and ensure that MISO satisfies its resource adequacy needs.

- Conducting auctions before each season so participants can optimize their offers for the next season based on prior results;
- Reducing accreditation for inflexible resources, including those with 24-hour lead times;
- Implementing a capacity replacement settlement market in lieu of the Capacity Replacement Non-Compliance Charge (CRNCC), to improve outage scheduling incentives and reduce the administrative burden on market participants;
- Improving the maintenance margin calculation;
- Improving the accreditation rules for emergency-only resources in the PRA;
- Modifying the hours used to accredit existing solar resources; and
- Modeling constraints in the PRA by assigning a zonal shift factor for each modeled constraint that reflects how the resources in each zone affect the flow on the constraint.

These improvements would allow the PRA to provide efficient economic signals to help ensure that the MISO region remains reliable as its generation fleet transitions.

External Transaction Scheduling and External Congestion

As in prior years, MISO remained a substantial net importer of power in 2025, importing an average of 1.8 GW per hour in real time over all interfaces and 2.0 GW per hour from PJM. Price differences at the interfaces between MISO and neighboring areas create incentives to schedule imports and exports between areas. We evaluate interface pricing in this report because of the key role it plays in facilitating external transaction scheduling, as well as Coordinated Transaction Scheduling (CTS) with PJM.

Efficient interchange is essential because poor interchange can reduce dispatch efficiency, increase uplift costs, and can create operating reserve shortages. In 2025, more than 60 percent of transactions with PJM and more than 67 percent of transactions with SPP were scheduled in the profitable direction, although many hours still exhibited large price differences that imply substantial unrealized production cost savings.

Interface pricing. Our evaluation of interface pricing shows that the prices at the PJM and SPP interfaces are not fully efficient for different reasons. At the PJM interface, the RTOs have implemented a "common interface" that assumes power associated with imports and exports is sourced from and sinks near the seam, which is not accurate; marginal generators are distributed throughout both systems. At the SPP interface, the value of M2M constraints is included redundantly in both RTOs' interface prices, which distorts the incentive to import and export. Hence, we recommend changes to MISO's interface pricing to address these issues.

Interchange coordination. MISO and PJM intended for Coordinated Transaction Scheduling (CTS) to improve interchange coordination. However, participation has been minimal because of high transmission charges and persistent forecast errors. In 2026, MISO proposed eliminating the product and considered replacing it with a more efficient alternative.

We recommend that MISO, PJM, and SPP replace CTS with interchange optimization (IO): a process to adjust the interchange in real time to converge prices between markets. Such a process could deliver enormous economic and reliability benefits, particularly in periods when one market is short of energy or operating reserves.

MISO, PJM, and SPP could leverage their alternate real-time case results to coordinate interchange more efficiently. They could exchange and evaluate data from the alternative load scenarios, including production cost changes and interface LMPs, to minimize aggregate production costs across markets. An IO clearing process would be simple to implement and could be configured to each RTO's preference. IO would allow for minimization of production costs among broader sets of generators and transmission paths.

Our discussion of IO appears in Section VII.B. We estimated that interchange optimization between MISO, PJM, and SPP could have reduced costs by $40 million, spread evenly across the three markets, between March 2025 and February 2026. More importantly, this analysis shows that IO would lower average real-time energy prices by roughly $2 per MWh in each market, which would lower the annual real-time market cost of energy in MISO by $1.4 billion. These price reductions occur because optimizing interchange between markets would substantially eliminate extremely high prices that occur when an RTO runs short of energy or reserves. This has become more frequent in MISO during evening ramp hours when solar output is falling rapidly when MISO has set real-time prices as high as $10,000 per MWh.

Demand Response and Energy Efficiency

Demand response is valuable if it contributes to improved operational reliability in the short term and lowers resource adequacy costs in the long term. MISO had over 14 GW of DR resources in 2025, which included 4.3 GW of behind-the-meter generation. Most of its DR capability is in the form of interruptible load developed under regulated utility programs. DR resources are registered in three primary MISO programs depending on their capabilities.

Load-Modifying Resources (LMRs). Almost 95 percent of MISO's DR resources are LMRs that can only be accessed after MISO has declared an emergency. We have long been concerned that the qualification and testing process for LMRs is too lax and invites fraud and that LMRs are not as accessible or as valuable as generating resources from a reliability perspective. We have worked closely with MISO to tighten LMR participation, testing, and accreditation rules, which FERC approved in 2025.

Demand Response Resources (DRRs). DRRs are a category of DR that can participate in the energy and ancillary services markets because they are assumed to be able to respond to MISO's real-time curtailment instructions. DRRs are divided into two subcategories:

- Type I: These resources can supply a fixed quantity of energy or reserves by interrupting load. These resources can qualify as FSRs and set price in ELMP[1]; and
- Type II: These resources can supply varying levels of energy or operating reserves on a five-minute basis and are eligible to set prices, just like generating resources.

DRR Type I resources accounted for nearly all DRR scheduling in 2025. Scheduling fell sharply in mid-2022 after we identified significant conduct issues that led two of the largest participants to cease participation. Although DRR Type I scheduling more than doubled in 2025 from 2024, total DRR Type I scheduling in 2025 was only six percent of the amount scheduled in 2021, when DRR scheduling was at its peak as a result of fraud we referred to FERC's Office of Enforcement.

In early 2025, MISO filed changes consistent with our longstanding concerns about DRR fraud, and FERC approved them. MISO also filed changes to Module D of the Tariff to allow DRR market power mitigation measures.

Emergency Demand Response Resources (EDRs). These are called in emergencies but are not obliged to offer and do not satisfy capacity requirements. FERC approved Tariff changes that will eliminate cross-registration beginning in June 2026, so EDRs will not be able to cross-register as LMRs and earn capacity revenue.

Energy Efficiency (EE). FERC issued a penalty of $1.2 billion against an energy efficiency supplier that had participated in MISO. We investigated and referred the participant to the Commission after the first auction in which it earned significant revenues -- $18 million. On the basis of our findings, MISO disqualified the participant and protected its participants from any future costs. PJM was much slower to identify and address this conduct, allowing more than $500 million in costs to be incurred. More recently, FERC approved MISO's Tariff provisions that eliminate EE participation in the PRA beginning in the 2026–2027 Planning Year, which we had recommended since 2020.

1 A resource can qualify as a Fast-Start Resource provided the DRR Type I resource can curtail demand within 60 minutes and offers a minimum run time of less than or equal to one hour.

Table of Recommendations

Although the markets performed well in 2025, we make 32 recommendations to further improve their performance. Six are new, while 26 were recommended previously. MISO addressed or we have withdrawn seven recommendations since our last report, and we are retiring an eighth because of anticipated changes in market rules. The table below shows the recommendations by market area, numbered with the year they were introduced and the recommendation number in that year. We also indicate those with the highest benefits or that are possible in the near term.

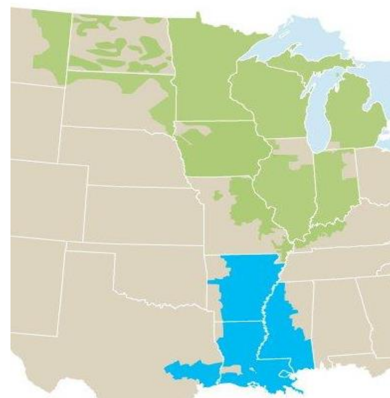
SOM Number	Recommendations	High Benefit	Near Term
Energy and Operating Reserve Markets and Pricing			
2025-1	Develop criteria for retroactive repricing of the market to mitigate the harm of repricing.		✓
2025-2	Reduce make-whole and operating reserve payments for deviating resources.		✓
2024-1	Modify RDT demand curve steps and RPE binding limits.		✓
2023-1	Align aggregate pricing nodes from the FTR market through real-time.		✓
2023-2	Enforce STR requirements in the load pockets.		✓
2021-2	Evaluate improvements to the emergency pricing assumptions applied to LMR curtailments.		
2020-1	Develop a real-time capacity product for uncertainty.	✓	
2012-3	Remove external congestion from interface prices.		✓
2012-5	Introduce a virtual spread product.		
Transmission Congestion			
2024-2	Shift a large share of transmission capability from the annual ARR allocation and FTR auction to seasonal and monthly auctions.		
2023-3	Develop tools to recommend decommitting resources committed in the day-ahead market.		
2022-1	Expand the TCDCs to allow MISO's market dispatch to reliably manage network flows.	✓	✓
2021-1	Work with TOs to identify and deploy economic transmission reconfiguration options.		
2019-1	Improve the relief request software for market-to-market coordination.		
2019-2	Improve the criteria for testing market-to-market constraints.		

SOM Number	Recommendations	High Benefit	Near Term
2016-3	Enhance authority to coordinate transmission and generation planned outages.		
2014-3	Seek joint operating agreements with neighboring control areas to improve congestion management and emergency coordination.		
Market and System Operations			
2024-4	Improve constraint management and dead bus criteria for Forced Off Asset Events.		
2023-5	Require descriptions in new or updated CROW tickets.		
2021-4	Develop a look-ahead dispatch and commitment model to optimally manage fluctuations in net load and the use of storage resources.	✓	
2020-2	Align transmission emergency and capacity emergency procedures and pricing.		✓
2019-4	Optimize CTS schedules every five minutes based on the RTOs' alternative real-time load scenarios (interchange optimization).	✓	
2016-6	Improve the accuracy of LAC recommendations and record operator responses to them.		✓
Resource Adequacy and Planning			
2025-3	Ensure alignment of capacity obligations with LMR capability and ensure that anticipated large loads are in the load forecast.		
2025-4	Replace CRNCC rules with a daily capacity balancing settlement.	✓	
2025-5	Improve capacity accreditation by reforming: 1) maintenance margin, 2) treatment of resources that are off control, 3) separate DLOL treatment of firm and non-firm gas resources, 4) the hours used to accredit existing solar resources.	✓	✓
2025-6	Develop penalties similar to LMR non-performance penalties for resources that offer emergency ranges and do not perform during emergencies.		
2023-6	Implement zonal capacity demand curves and near-term improvements in local clearing requirements.		
2022-4	Improve the LRTP processes and benefit evaluations.	✓	✓
2022-5	Implement jointly optimized annual offer parameters in the seasonal capacity market.		
2015-6	Improve the modeling of transmission constraints in the PRA.		
2014-6	Define local resource zones based on transmission constraints and local reliability requirements.		

I. Introduction

As the Independent Market Monitor (IMM) for MISO, we evaluate the competitive performance and operation of MISO's electricity markets. Overall, we found that the markets performed competitively and have been evolving to meet the challenges that lay ahead. This annual report summarizes our evaluation and provides our recommendations for future improvements.

MISO operates wholesale electricity markets designed to efficiently satisfy the needs of the MISO system, which encompasses parts of 15 states in the Midwest and South. The MISO markets include:



Day-Ahead and Real-Time Energy and Ancillary Services Markets – utilize the lowest-cost resources to satisfy system demands, manage transmission flows, and provide economic signals for short- and long-run decisions by participants. These markets jointly optimize the scheduling of resources to produce energy and provide contingency reserves, short-term reserves, and regulation.

Financial Transmission Rights (FTRs) Market – facilitates the sale of FTRs that provide holders an entitlement to day-ahead congestion revenues, allowing them to hedge congestion.

Capacity Market – provides the economic signals needed to satisfy the resource adequacy requirements of the system and is implemented through the Planning Resource Auction (PRA).

These markets provide a robust foundation for the long-term challenges that lie ahead. Nonetheless, we identify a number of potential improvements that will allow the markets to operate more efficiently and provide better economic signals. MISO continued to respond to our past recommendations in 2025. Key improvements included:

- Capacity Market: MISO implemented a reliability-based demand curve in 2025 and is reforming its accreditation to reflect resources' marginal contribution to the reliability of the system in the tightest hours. MISO also eliminated the eligibility of energy efficiency resources in its capacity market, a longstanding IMM recommendation.
- Energy Market: MISO implemented its shortage pricing reforms to allow energy and ancillary service prices to better reflect the expected potential costs of load shedding.
- Market Operations: MISO implemented its Uninstructed Deviation Enhancement flag to provide better dispatch information to renewable resources, improved uncertainty management, and filed Tariff changes addressing various Demand Response concerns.

These changes have improved the performance of the markets and the operation of the system. We discuss other changes in this report to improve MISO's market design and operations and present our recommendations in Section X of the Report.

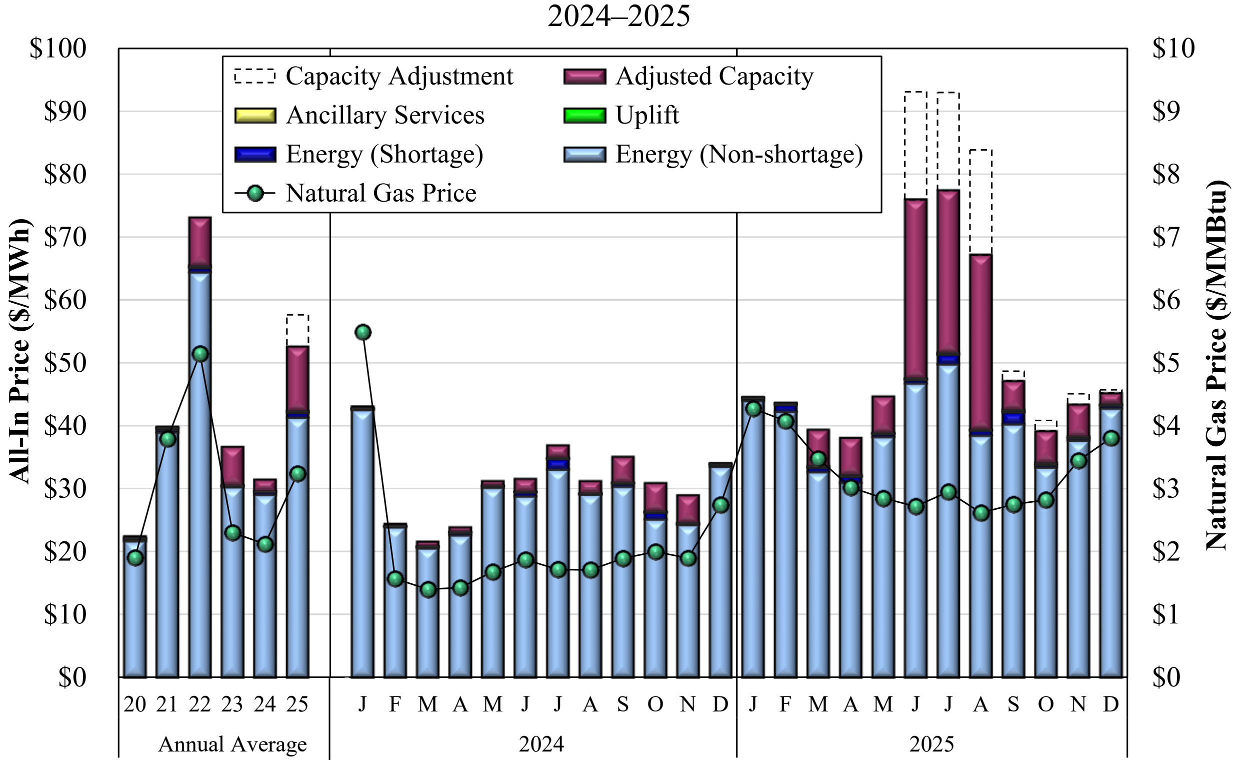
II. Price and Load Trends

MISO's wholesale electricity markets in the day-ahead and real-time timeframes facilitate efficient resource commitment and dispatch to meet the needs of the MISO system. The resulting prices also play a key role in providing long-term investment incentives to MISO participants. This section reviews overall prices, generation, and load in these markets. It also discusses noteworthy events during the year that had significant market impacts.

A. Market Prices in 2025

Figure 1 summarizes changes in energy prices and other market costs through the "all-in price" of electricity, a measure of the total cost of serving load in MISO's markets. The all-in price equals the load-weighted average real-time energy price plus capacity, ancillary services, and real-time uplift costs per MWh of real-time load.[2] We separately show the portion of the all-in price associated with energy shortage pricing. The maroon bars represent load-weighted average capacity clearing prices. Figure 1 also shows average natural gas prices to highlight the relationship between natural gas and energy prices.

Figure 1: All-In Price of Electricity
2024–2025



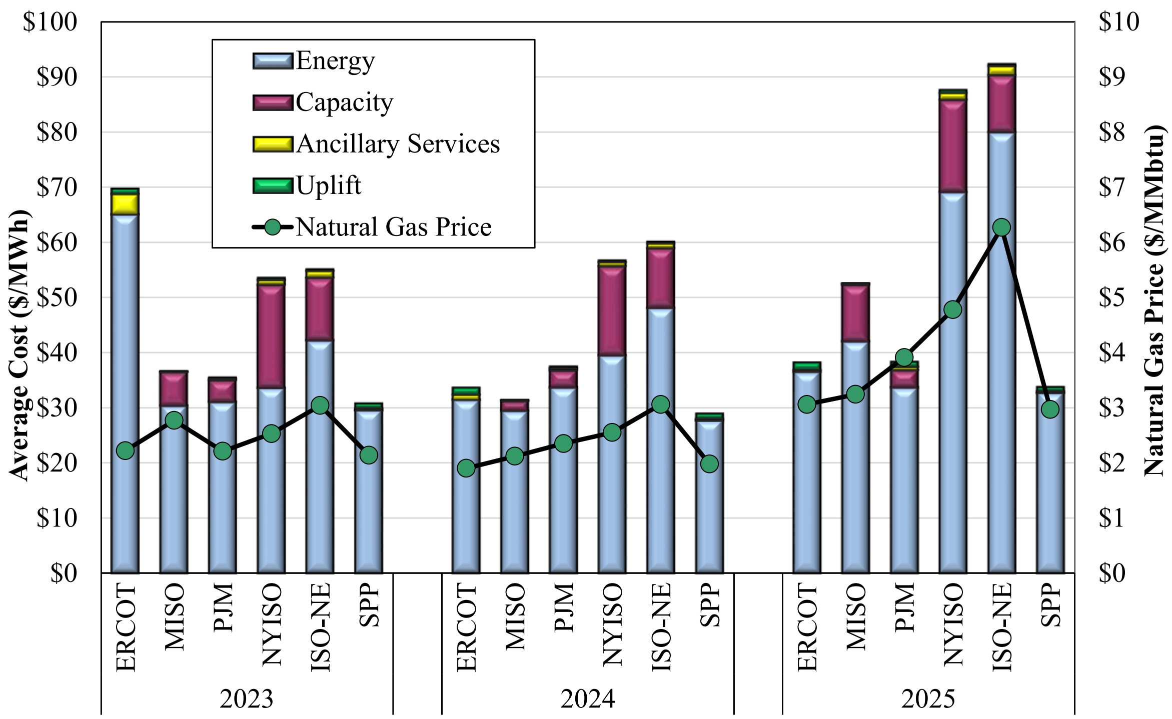
2 The non-energy costs are shown on a per MWh basis by dividing these annual costs by real-time load.

This shows the all-in price rose 67 percent in 2025 to average roughly $53 per MWh. This increase was largely because:

- Energy prices rose 43 percent as natural gas climbed by 53 and 58 percent at Chicago Citygates and Henry Hub, respectively.
- Shortage pricing rose 67 percent with shortage intervals doubling to 70 intervals in 2025. Shortages in the evening as the sun sets have grown as solar entry has rapidly expanded.
- The capacity component rose sharply by 462 percent from 2024 because MISO implemented the sloped RBDC for the 2025–2026 Planning Year.
- The uplift component increased by 64 percent to $0.07 per MWh, but it remains low relative to pre-2023 levels due to improvements in MISO's commitment practices.[3]

Natural gas prices continued to be a primary driver of energy prices. This is expected because fuel costs are the majority of most suppliers' marginal production costs. Competition produces strong incentives for suppliers to offer at their marginal costs, so fuel price changes cause comparable offer price changes. Figure 2 shows all-in prices in the Eastern RTOs and ERCOT.

Figure 2: Cross Market All-In Price Comparison
2023–2025



Each of these RTO markets has converged to similar market designs, including nodal energy markets, operating reserve and regulation markets, and capacity markets (except in ERCOT and

3 Uplift payments include Revenue Sufficiency Guarantee (RSG) payments made to ensure resources cover their as-offered costs, and Price Volatility Make-Whole Payments (PVMWPs).

SPP). However, market rules can vary substantially. The market prices and costs in different RTOs are affected by generation type and vintage, input fuel prices, and transmission capability.

In Figure 2, MISO has exhibited lower all-in prices than NYISO and ISO-NE because of low natural gas prices and relatively weak shortage pricing. In 2025, MISO enhanced shortage pricing by increasing the Value of Lost Load and reforming its Operating Reserve Demand Curve. MISO also improved its capacity auction design and produced more efficient capacity clearing prices in the 2025–2026 auction. ERCOT lacks a capacity market entirely but has much stronger shortage pricing. Higher gas prices reflecting pipeline constraints tend to cause ISO New England's relatively high energy prices. In NYISO, energy and capacity prices have risen in recent years as 800 MW of peaking resources retired because of air permit limits.

B. Fuel Prices and Energy Production

MISO's resource mix continued to evolve in 2025. On an Unforced Capacity (UCAP) basis, MISO lost 1.1 GW to retirements and suspensions and added 3.1 GW of new resources. Just under half of those additions came from solar resources that came online in 2025. The additions also included a new 650 MW combined-cycle unit in the South, 400 MW of gas replacement projects in the Midwest, and 370 MW of battery electric storage resources (ESR).

Table 1 summarizes the share of unforced capacity and energy output by resource type, as well as how frequently each resource type was marginal in setting system-wide marginal energy prices (SMP) and locational marginal energy prices (LMP) in 2024 and 2025.

Table 1: Capacity, Energy Output, and Price-Setting by Fuel Type

	Unforced Capacity				Energy Output		Price Setting			
	Total (MW)		Share (%)		Share (%)		SMP (%)		LMP (%)	
	2024	2025	2024	2025	2024	2025	2024	2025	2024	2025
Nuclear	10,987	11,124	8%	8%	14%	14%	0%	0%	0%	0%
Coal	36,880	36,174	28%	27%	26%	29%	33%	26%	75%	64%
Natural Gas	64,269	65,525	48%	49%	38%	35%	65%	72%	91%	91%
Oil	1,430	1,319	1%	1%	0%	0%	0%	0%	0%	0%
Hydro	3,813	3,883	3%	3%	1%	1%	1%	0%	2%	2%
Wind	11,504	8,236	9%	6%	15%	15%	0%	1%	64%	60%
Solar	3,471	6,228	3%	5%	2%	5%	0%	0%	10%	17%
Battery	265	790	0%	1%	0%	0%	0%	2%	0%	2%
Other	1,176	1,029	1%	1%	3%	1%	0%	0%	2%	3%
Total	**132,620**	**133,278**								

Energy Output Shares. The share of energy produced by natural gas resources decreased by 4 percentage points, while the share produced by coal increased by 3 percentage points, largely because the 53 percent increase in gas prices changed the relative economics of those resources. Accredited wind capacity shrank by about 3 GW because of the underlying change in the effective load carrying capacity (ELCC) values used to accredit wind, and its share of energy output remained 15 percent in 2025. The share of energy produced by solar increased to 5 percent because of new resource additions.

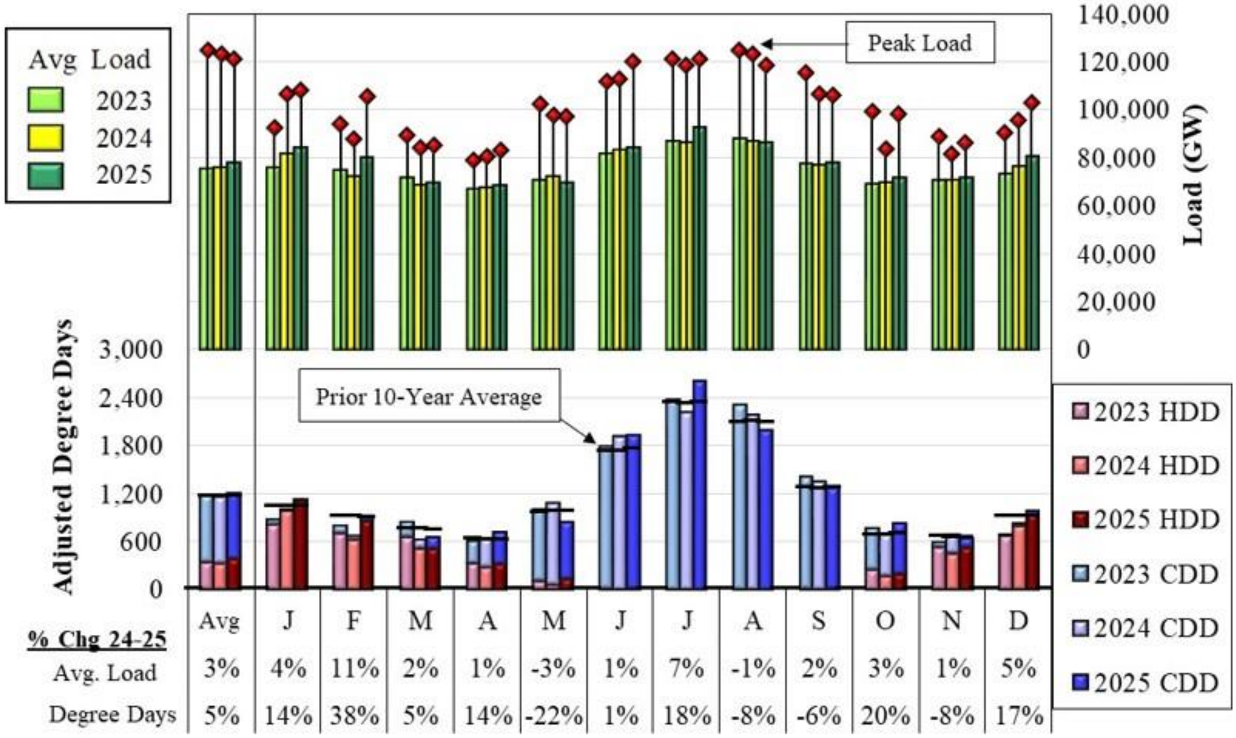
Price-Setting. Coal's role in setting system-wide prices, the system marginal price (SMP), declined from 33 percent in 2024 to 26 percent in 2025. Conversely, gas-fired resources set the SMP more frequently, rising from 65 percent in 2024 to 72 percent of intervals in 2025. Congestion often causes natural gas-fired units to set prices in local areas to manage constraint flows, resulting in gas-fired units setting locational prices in 91 percent of intervals even when lower-cost units set the system-wide price. Wind units set locational prices in 60 percent of all intervals, typically in areas that are export constrained when wind output is high. Solar units set locational prices in 17 percent of all intervals. That share will likely increase substantially in the coming years as solar capacity continues to be added to the system.

C. Load and Weather Patterns

Economic and demographic changes in the region drive long-term load trends, but weather generally determines short-term load patterns. Figure 3 shows weather's influence by comparing heating and cooling needs with monthly average load over the past two years. The top panel shows monthly average load in the bars and peak monthly load in the diamonds. The bottom panel shows monthly Heating Degree Days (HDD) and Cooling Degree Days (CDD) summed across six representative locations in MISO.[4]

4 HDDs and CDDs are defined using aggregate daily temperatures relative to a base temperature (65°F). To normalize the load impacts of HDDs and CDDs, we inflate CDDs by 6.07 (based on a regression analysis).

Figure 3: Heating and Cooling Degree Days
2023–2025

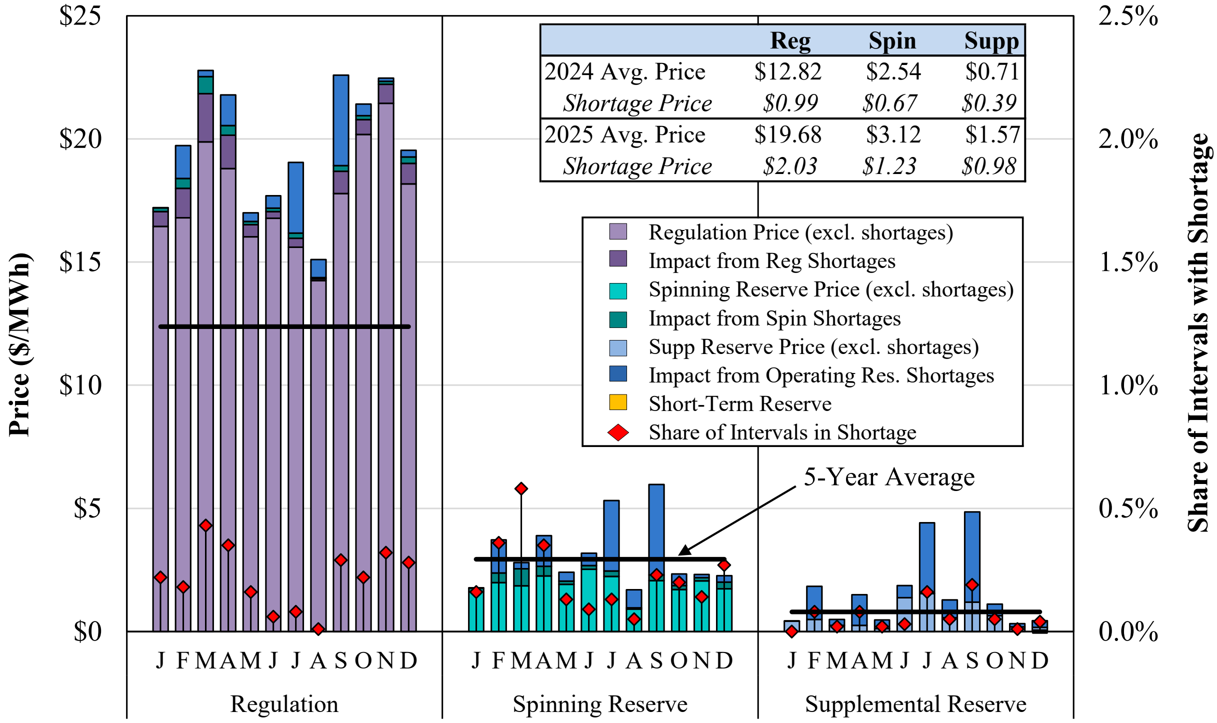


In 2025, the system average load rose by 2.8 percent from the prior year while the degree days rose 4.7 percent. MISO's annual peak load of 122 GW occurred on July 29 because hot, MISO-wide temperatures led to high cooling demand. The annual peak load was in line with the 50/50 forecasted peak of 123 GW from MISO's *2025 Summer Seasonal Assessment*. Subsection E below discusses in detail the operational challenges that occurred during extreme weather events throughout the year.

D. Ancillary Services Markets

Since their inception in 2009, co-optimized ancillary services markets have produced significant benefits, improving flexibility and lowering the cost of satisfying the system's reliability needs. These markets have also facilitated more efficient energy pricing that reflects the economic trade-off between reserves and energy, particularly during shortage conditions. For each product, Figure 4 shows the monthly average real-time price, the contribution of shortage pricing to that price, and the share of intervals in shortage. The figure also shows the 5-year average price for the reserve products,

Figure 4: Real-Time ASM Prices and Shortage Frequency
2025



Supplemental (offline) reserves only meet the market-wide Contingency Reserve requirement (i.e., 10-minute operating reserves). Spinning reserves can satisfy both the Contingency Reserve and spinning reserve requirements, so the spinning reserve price will always equal or exceed the Contingency Reserve price. Similarly, regulation prices include components associated with spinning reserve and Contingency Reserve shortages.[5] Likewise, energy prices include all ASM shortage values plus the marginal cost of producing energy. MISO's demand curves specify the maximum willingness-to-pay for each reserve product. When the market is short of a reserve product, its demand curve sets the market clearing price and affects the prices of higher-valued reserves and energy through the co-optimized market clearing. Figure 4 shows that average clearing prices rose for all reserve products in 2025, except for a slight decline in day-ahead ramp capability, because of higher natural gas prices. The increase in regulation was partly due to MISO raising the regulation floor requirement from 400 MW to 600 MW in June 2024 after CPS1 ("Control Performance Standard 1") decreased in order to improve this score.[6]

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5 The demand curve for regulation, which is indexed to natural gas prices, averaged $236.21 per MWh, up from $139.76 per MWh in 2024. The spinning reserve penalty price was unchanged at $65 per MWh (for shortages < 10% of the reserve requirement) and $98 per MWh (for shortages > 10%).

6 Each Balancing Authority shall achieve, as a minimum, Requirement 1 (CPS1) compliance of 100% by NERC Standard BAL-001. MISO publishes the CPS1 performance every month at the Monthly Operations Report. https://www.misoenergy.org/markets-and-operations/markets-and-operations/

Short-Term Reserves. MISO's 30-minute reserve product (short-term reserves or "STR") satisfies market-wide and sub-regional requirements. MISO enforces the subregional STR requirements through reserve procurement enhancement (RPE) constraints over the Regional Directional Transfer (RDT) constraint. The RPE binds when headroom on the RDT plus available STR in the importing subregion is limited.

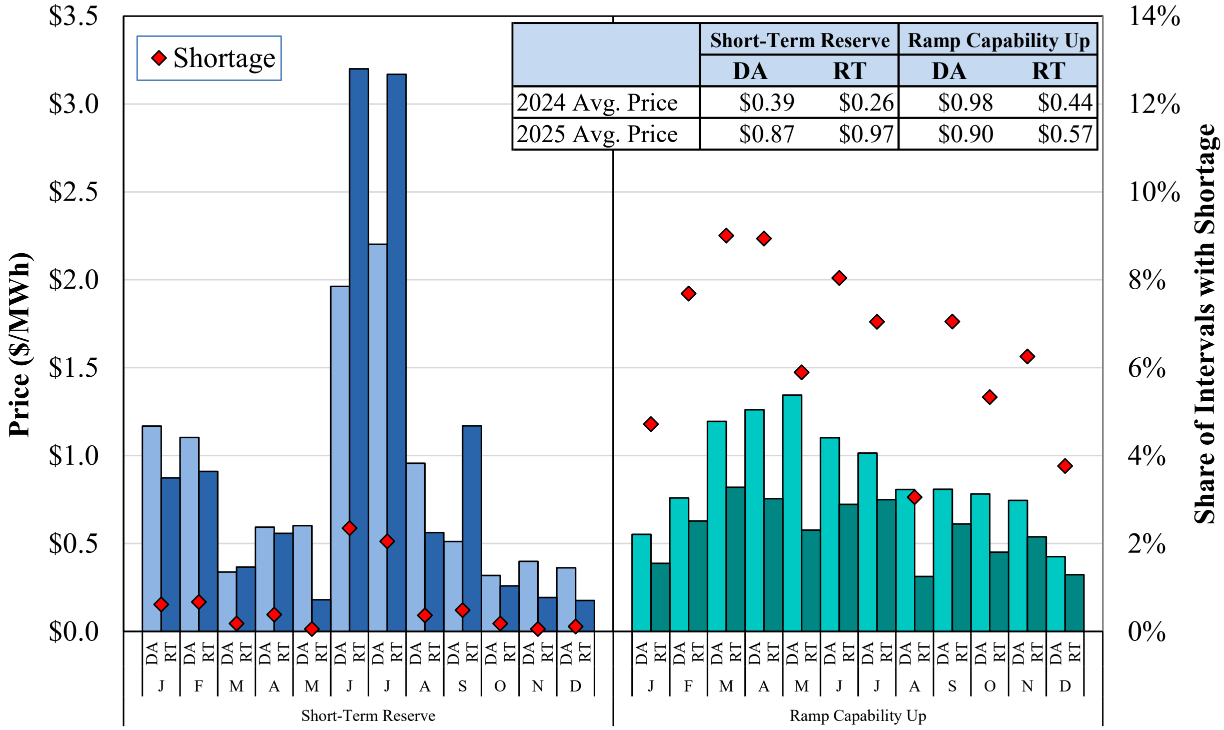
We continue to recommend that MISO expand the RPE constraints to enforce STR requirements in local reserve zones with VLR needs. This would provide efficient incentives for suppliers to invest in fast-start units that can satisfy the VLR requirements. It would also reduce the need to make out-of-market commitments of high-cost units in those areas.

STR prices averaged close to $1 per MWh in the day-ahead and real-time markets in 2025, more than double the average clearing prices in 2024. MISO began dynamically adjusting STR requirements in 2024 to account for uncertainty. On high-uncertainty days, it increased the requirements to address the risk of unexpected changes in supply or demand. This change is beneficial because higher requirements can lead to higher STR prices (including shortage pricing), which incentivize good generator performance and prompt increased net imports that ultimately tend to mitigate uncertainty.

In 2024, we identified a pricing inefficiency in local STR clearing when the RDT binds in the South-to-North direction because of the combined effects of the RPE and RDT constraints. Prices throughout the Midwest reflect the shadow prices of the RDT and RPE constraints when both are violated, raising prices by up to $700 per MWh ($500 per MWh for the RDT violation plus $200 per MWh for the RPE). Adding $200 per MWh for RPE violations when the RDT is already violated is inefficient. Overpricing RDT violations by $200 per MWh when the constraint is in small violation is costly. It can also cause units' dispatch to violate local constraints because the cost of the RDT violation is reflected in the marginal energy component of price. Hence, we recommend MISO adjust the RDT demand curve so the total price impact when the RDT and RPE bind simultaneously does not exceed $500 per MWh.

Ramp Product. MISO also implemented a ramp product that causes its day-ahead and real-time markets to schedule resources to maintain additional capability to ramp up and down. Although this can raise system costs slightly, it will lower the costs of satisfying system needs when the system becomes ramp-constrained. Figure 5 shows the average day-ahead and real-time STR prices, along with the ramp capability up product prices.

Figure 5: Short-Term Reserves and Ramp Product Prices
2025



	Short-Term Reserve		Ramp Capability Up	
	DA	RT	DA	RT
2024 Avg. Price	$0.39	$0.26	$0.98	$0.44
2025 Avg. Price	$0.87	$0.97	$0.90	$0.57

The ramp capability up product saw similar average prices in 2025 compared to 2024, and there were material instances of ramp up shortages in each month of the year. Most ramp up shortage intervals occurred during the evening net load ramping period, typically as the sun was setting and significant dispatchable ramp was needed to address system ramp. We expect this pattern to continue and grow as solar penetration continues to grow in MISO.

E. Significant Events and Market Outcomes

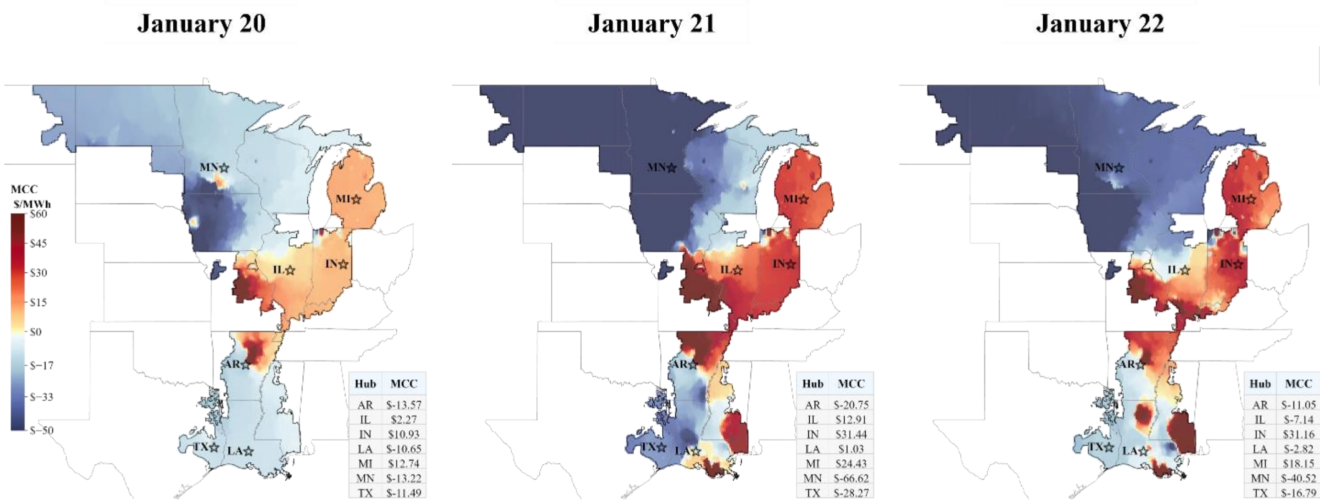
MISO experienced significant weather events in 2025 during the winter and summer, including Winter Storm Enzo in January and extended heatwaves in June and July. In addition, MISO called transmission emergencies in MISO South on four days and implemented a significant transmission-related repricing. This subsection discusses each of these events.

Winter Storm Enzo

Over the Martin Luther King Jr. holiday weekend, winter storm conditions spread across the U.S. continent, bringing frigid temperatures, ice, and snow to MISO South. New Orleans received 10 inches of snow, more than it had in over 100 years, and MISO South set a new winter peak load record of 33.1 GW. MISO forecasted high uncertainty and increased its day-ahead and real-time STR requirements by 900 MW in every hour. This led to higher prices throughout the event, sustaining imports and improving MISO's ability to manage the uncertainty associated with 9 GW of forced outages. Unlike in prior storms, MISO did not enter its emergency procedures.

Figure 6 illustrates daily congestion patterns during the event with heat maps of the average congestion components of prices for the three days around the event. Warmer colors represent higher congestion components, and cooler colors represent lower congestion components. The color intensity indicates the relative magnitude of congestion. Generally, power flows across the system from areas with cooler colors toward areas with warmer colors.

Figure 6: Congestion During Winter Storm Enzo



Congestion during Enzo was $100 million, much lower than in prior storms, partly because the extraordinary wheels and exports to other areas seen in prior storms did not occur. MISO managed the storm reliably without incurring significant costs. Uplift totaled just $2.6 million, down more than 90 percent from Winter Storms Uri and Elliott and two-thirds from Winter Storm Heather. This was a major improvement over prior winter storm events and reflected the evolution of MISO's processes to prepare for these kinds of events and manage their uncertainty through increased STR requirements.

Transmission Emergencies and Load-Shedding Events in MISO South

In the spring, MISO experienced two significant load-shedding events in the South. The first occurred in early April, when a large storm system damaged the local transmission system. The second event was caused by a confluence of planned and forced transmission and generation outages that materially reduced flows into one of the MISO South load pockets.[7]

7 Load pockets are electrical regions of the grid where limited import capability causes MISO to rely on a certain amount of generation within the region to ensure that it can withstand the loss of 2 contingencies. Typically, constraints are monitored for a single contingency but given the limits on imports into the load pockets, generators in these areas are committed to ensure that load will not have to be shed after the loss of 2 contingencies. MISO has operating guides for these areas that tell them how many resources they need to commit for the next day to ensure sufficient generation will be online for the peak load hour the next day.

April 2 Load Shed in MISO and SPP

Figure 7: Load Shed Event in MISO and SPP

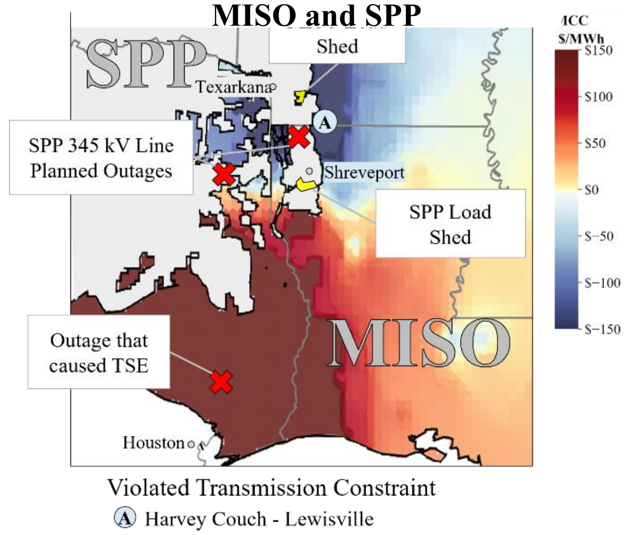


Figure 7 shows congestion patterns during a load shedding event on April 2 that resulted from planned and unplanned transmission outages along the seam between MISO and SPP. As the figure shows, this area overlaps with SPP's footprint, so significant outages in the region affect both systems. Leading up to the event, SPP had approved two 345 kV transmission outages that limited flows into SPP's load in Southwestern Arkansas while some planned generation outages in SPP were scheduled. Storms in the region caused additional transmission outages. MISO identified emerging low-voltage issues because of the outages, prompting it to declare transmission emergencies to keep flows on its system at reliable levels.

After a key line tripped, MISO's operators identified an Interconnection Reliability Operating Limit (IROL) constraint that could lead to cascading outages so MISO directed 100 MW of load shedding in SPP and 27 MW of load shedding in MISO. Because several constraints were violated, congestion in the South totaled $10 million on this day. MISO's situational awareness and rapid operator actions protected reliability in both areas during this event.

Consistent with our recommendation, MISO attempted to price the areas with load shedding at the current VOLL of $3500 per MWh by raising the shadow price on the IROL constraint to VOLL. This was not successful because the load was not near the constraint so prices rose by far less than VOLL. MISO identified process improvements to reflect VOLL pricing for targeted load shed in the future.

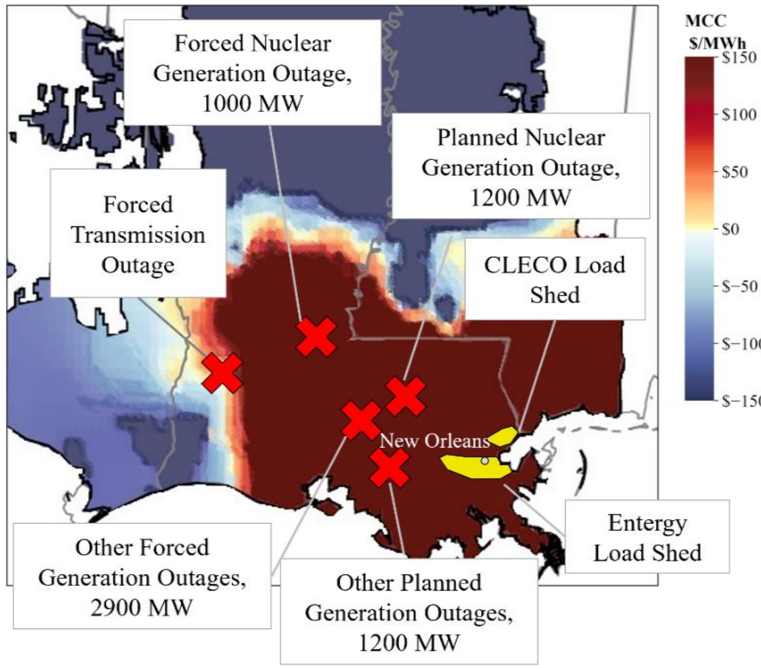
MISO Load Shed on May 25

On May 25, MISO ordered Entergy to shed 500 MW of load in New Orleans and CLECO to shed 100 MW of load above Lake Pontchartrain because of an unlikely combination of planned and forced outages affecting the Amite South load pocket. The events on May 25 were set in motion earlier in the Spring, when a series of forced and planned outages significantly altered transmission flows into Amite South. In late March, storm activity caused a key 500 kV forced transmission outage, reducing power flows from the Southeast Texas (SETEX) load pocket into Amite South. In late April, a 1,200 MW nuclear unit in the load pocket went offline for planned maintenance along with another key transmission outage. Flows into the load pocket shifted, straining the inlet transmission paths from the northern part of the load pocket to serve load further south.

From May 21 to 23, MISO lost a critical nuclear unit and a conventional steam unit. By May 24, severe loading on the inlet constraints to Amite South caused MISO to manually order a key unit offline because it would have increased the loading on the constraint. MISO studied reconfiguration options to keep the unit online the next day.

Figure 8 shows a heatmap of the marginal congestion component of prices on May 25. The very dark area roughly matches the Amite South load pocket, although outages in that region expanded it slightly from its traditional shape. The figure also shows the key contributing factors and the area of the load shed. The red X's indicate the approximate locations of the planned and forced generation and transmission outages that contributed to the issue, and the yellow highlighted area indicates where the load shedding occurred.

Figure 8: May 25th Load Shed Event in Amite South



On May 25, as transmission flows reached critical levels, MISO implemented the reconfiguration it had studied to keep the unit online, but this increased flows on the constraint. MISO identified the constraint as an IROL constraint that could lead to cascading outages and blackouts.

MISO declared a transmission emergency and took several actions, including:

- Activating emergency output ranges on generation in the affected area;
- Calling for transmission line loading relief (TLR) that curtailed transactions between TVA and Southern Company;
- Implementing a reconfiguration to mitigate flows on the constraint; and
- Adjusting the Marginal Value Limits for 6 constraints, including pricing the emergency constraint at VOLL.

Ultimately, these actions were not sufficient, so MISO ordered the load shedding by Entergy and Cleco at 3 pm local time. Several issues limited the effectiveness of the actions MISO took before the load shedding:

- Several resources did not follow MISO's dispatch instructions into the emergency ranges, and MISO was only able to access 35 of the 105 MW of offered emergency energy in the first 20 minutes of the event. Some units did not follow their dispatch instructions, while others provided less emergency energy because they were delayed or went off control.

- MISO did not deploy LMRs in the area because it had not determined which LMRs were in locations that would help relieve the constraint. We identified 160 MW of available LMRs in the load pocket.
- One curtailed solar unit did not follow its curtailment instructions, contributing to overloads on the most severely impacted constraint.

To address future events, we recommend MISO:

1. Establish penalty provisions for generation non-performance in emergency ranges that mirror the proposed penalty provisions for LMRs;
2. Develop local STR requirements for load pockets that would better incentivize resources in these areas;
3. Develop processes to decommit or cancel starts when that is the best option—this would have reduced flows on the critical constraint on May 25; and
4. Improve LMR location information and establish a process to call LMRs in advance of transmission emergencies. MISO will require locational information under its DR/ER filing made this spring, but the implementation date is the 2028–2029 Planning Year. Collecting this information sooner would be beneficial.

Ultimately, we find that the load shedding instructed by MISO was necessary and helped avoid the risk of broader reliability issues, including cascading outages.

Summer Heat Waves and Challenging Operational Conditions

The U.S. experienced hotter-than-normal temperatures on multiple days in June and July. Figure 9 shows a matrix of declarations that Local Balancing Authorities in the Eastern Interconnection made during the summer of 2025 related to hot weather and capacity sufficiency concerns.

Figure 9: Eastern Interconnection Declarations
Summer 2025

	Jun.-2025				Jul.-2025						
	22	23	24	25	15	16	24	25	28	29	30
MISO	Cons. Ops	EEA1 Midwest	Max Gen Warning Midwest	Cons. Ops	Cons. Ops		Capacity Advisory		Max Gen Alert	Max Gen Warning	Severe Weather Alert
PJM	Hot Weather Alert	EEA1	EEA1	EEA1	EEA1	EEA1	EEA1	EEA1	EEA1	EEA1	EEA1
SPP			EEA1			Weather Advisory				Resource Advisory	Resource Advisory
ESO	Severe Weather Alert	Cons. Ops	EEA1		Cons. Ops		Cons. Ops		EEA1	EEA1	
TVA	Cons. Ops	Cons. Ops	EEA1	Cons. Ops			Cons. Ops	Cons. Ops	Power Supply Alert	Power Supply Alert	Power Supply Alert
VACAR		EEA2	EEA1	EEA1					EEA1	Cons. Ops	Cons. Ops
NYISO			EEA1	EEA1						EEA1	
ISO-NE			EEA1								

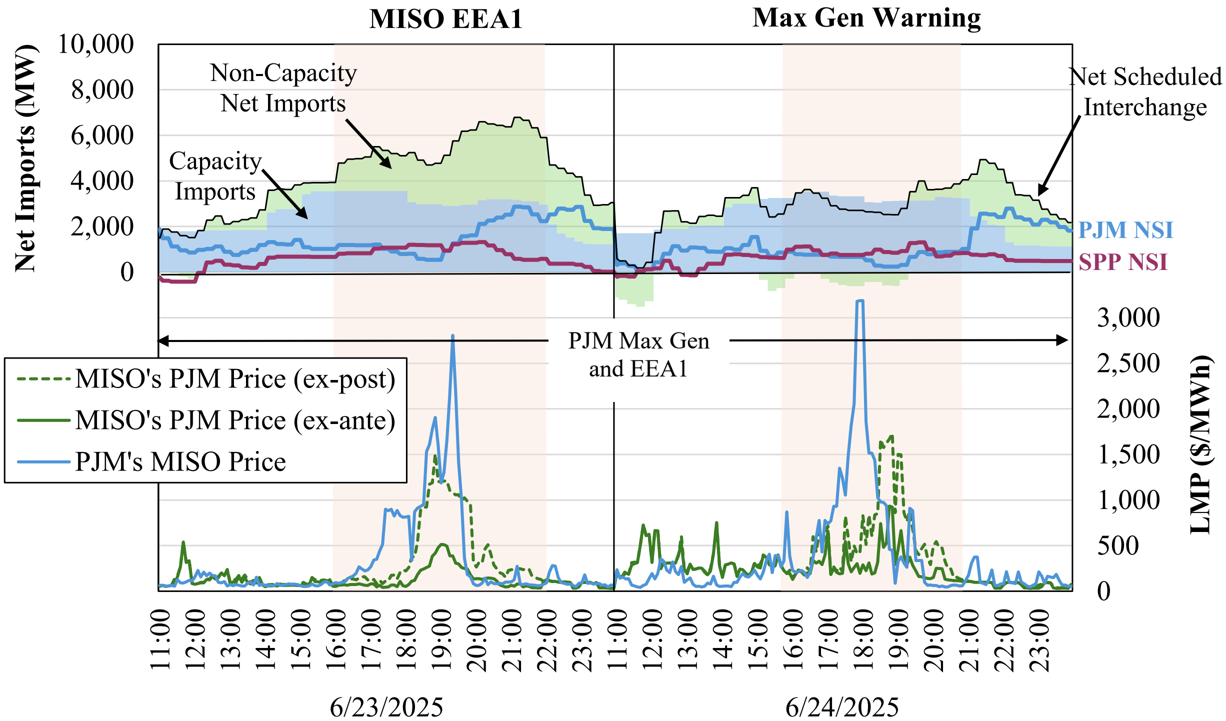
This figure shows that almost all balancing areas in the Eastern Interconnection had some level of emergency during the summer, and PJM alone experienced 10 days of emergencies. In contrast, although MISO experienced hot weather, it escalated to a Maximum Generation Emergency Step 1 (EEA1") in the Midwest on only one day, June 23, 2025.

June Heat Wave and Midwest Emergency Event

On June 23, MISO declared an EEA1 in the Midwest to access emergency capacity because constraints trapped over 4 GW of generation in the South. MISO dispatched 565 MW of emergency energy in the Midwest, which underscores the need for non-performance penalties for emergency ranges.

On June 24, seven other control areas were in EEA1, and MISO declared a Max Gen Warning to curtail non-firm exports but did not escalate to an EEA. When MISO enters its emergency procedures, its ELMP construct activates emergency pricing. Figure 10 shows the effects of MISO's emergency pricing on MISO's imports. The top panel shows scheduled imports and separately identifies the external capacity resources that must schedule into MISO during a Max Gen Warning. The bottom panel, plotted against the right axis, shows MISO's ex ante and ex post prices that include the effects of emergency pricing and PJM's interface price for MISO.

Figure 10: Emergency and ELMP Pricing
June 23–24, 2025



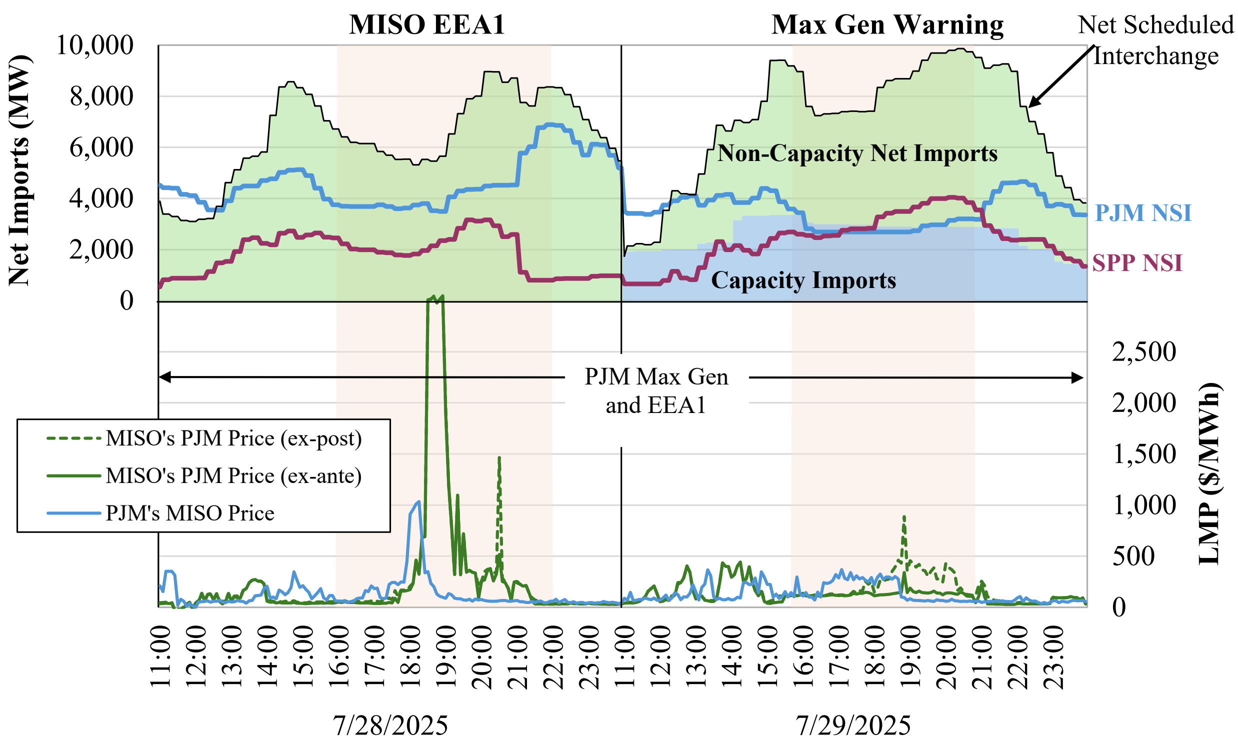
MISO's emergency pricing sent efficient price signals that were critical to maintaining MISO's imports when conditions were tightest. MISO's ex post energy prices that reflected the emergency pricing were 2.5 times higher than its ex ante prices during the events. These efficient price signals prompted large imports from MISO's neighbors and helped maintain reliability during the tightest periods, mitigating the need for MISO to advance to an EEA1.

Heat Wave and Transmission Emergency in July

In late July, hotter-than-average temperatures caused MISO to enter emergency procedures on July 28 and July 29. On July 28, MISO experienced a 40-minute operating reserve (OR) shortage because of significant load and renewable forecast errors. During the shortage, a 500 kV forced transmission outage in the South stranded 1.8 GW of generation and operators manually re-dispatched it down. MISO then declared a transmission emergency, and flows across the RDT reversed direction, transferring power from the Midwest to the South to replace the stranded generation.

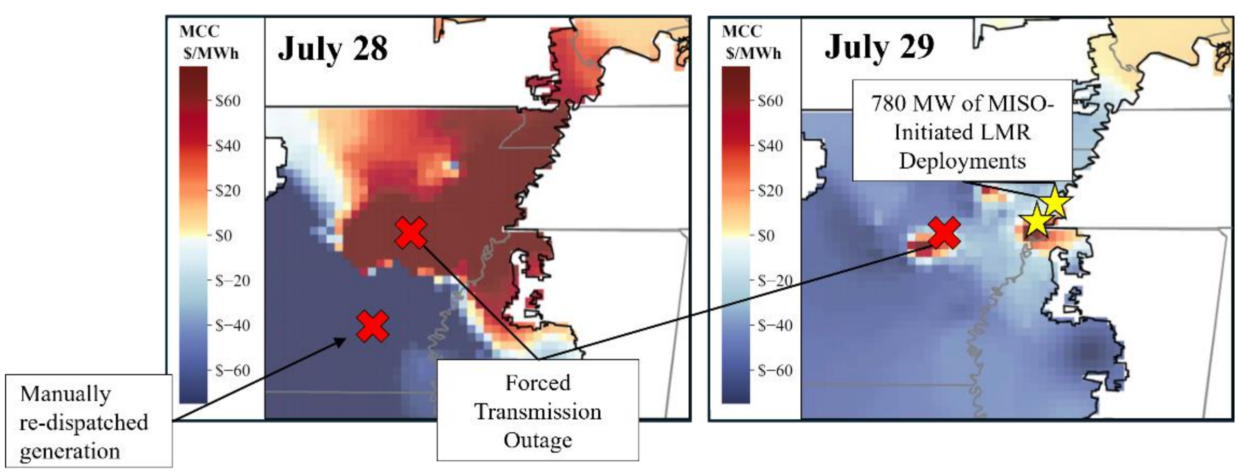
Figure 11 shows the MISO ex post and ex ante prices compared to PJM's price for MISO in the bottom panel. The top panel shows the imports scheduled into MISO for those days. Figure 11 shows that imports into MISO responded to the difference between the MISO's PJM interface price and PJM's interface price for MISO. On July 28, when MISO's prices averaged $3100 per MWh for almost 40 minutes, imports from PJM rose sharply soon afterward. Just prior to MISO's OR shortage, imports fell as prices in PJM rose to nearly $1000 per MWh. A similar pattern occurred the following day, when MISO's ex post prices rose above PJM prices and substantial imports were scheduled into MISO.

Figure 11: MISO Ex Post and Ex Ante Prices and Imports
July 28–29, 2025



On July 29, MISO declared a local transmission emergency in the South related to the major transmission outage that began the prior day. MISO scheduled 780 MW of 6-hour lead-time LMRs to reduce flows on the affected transmission constraints. Figure 12 shows a congestion heatmap of the affected area on July 28 and 29. The X's indicate the location of the transmission outage and the generators that MISO manually redispatched to manage conditions.

Figure 12: Map of Transmission Emergency in MISO South

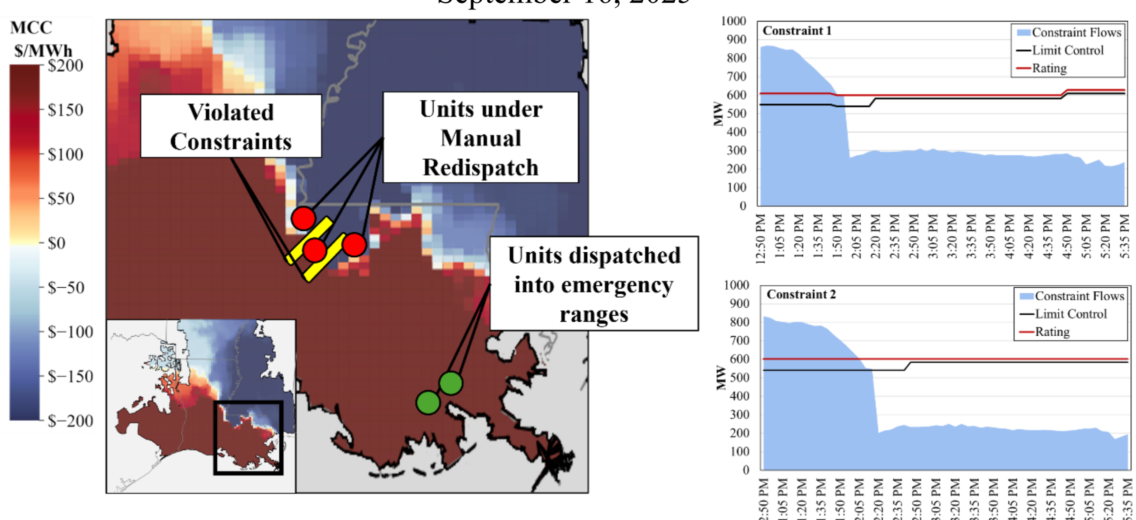


Just before the transmission emergency began on July 29, the 500 kV element that had tripped returned to service. MISO did not cancel the transmission emergency or the LMR schedules because it was uncertain whether the line would remain in service. MISO currently does not have exit criteria in its emergency procedures, which can cause it to remain in an emergency longer than necessary. We recommend that MISO incorporate exit criteria into its emergency procedures to determine when it may be appropriate to end emergency conditions.

September Local Transmission Emergency in MISO South

On September 16, a major 500 kV transmission element went out of service in MISO South, overloading 2 constraints and causing $12 million in congestion. Figure 13 shows a heatmap of the marginal congestion components of prices on the left. The map shows the approximate locations of the two key overloaded constraints, the approximate locations of the generators that received MISO reliability directives to manage the constraints, shown as red and green dots, and the locations of the two constraints, shown as yellow dashed bars. The right panel illustrates flows over the affected constraints in the blue shaded area, the constraint ratings in red lines, and the limits used in MISO's dispatch model in black lines. The blue shaded area above the red line indicates when the constraints were in severe violation.

Figure 13: MISO South Local Transmission Emergency
September 16, 2025



MISO operators declared a Transmission Emergency and took multiple actions to avoid firm load shed, including:

- Raised the top of the TCDC for the impacted constraints to $8000 per MWh to achieve near-VOLL pricing at the most impacted locations, reflecting the reliability conditions;
- Started 700 MW of generation to manage the constraints, including early starts for multiple units with day-ahead commitments;

- Dispatched two units into their offered emergency ranges; and
- Manually re-dispatched (MRD) a nuclear unit and three other large units. The MRD continued long after the line returned and produced $800,000 in DAMAP.

The manual redispatches' effects on constraint flows are evident when the blue shading falls below the line ratings and limits in the figures on the right. Operators' actions were key to preventing firm load shed, and improved communications helped ensure units responded in their emergency ranges. Although the MRDs produced quick initial responses, improved TCDCs would substantially lower costs and better manage the violated constraints.

One resource that MISO manually re-dispatched was located between two competing constraints.[8] We analyzed the event by rerunning MISO's market dispatch model using our recommended 10-step Transmission Constraint Demand Curves (TCDC) for the two competing constraints. Our analysis indicated that the market could have better determined the optimal output of the resources. Almost all DAMAP that was incurred could have been avoided. We continue to recommend that MISO expand the TCDCs to 10 steps, with maximum steps high enough to achieve VOLL pricing at impacted locations and to allow the market to optimally manage transmission violations.

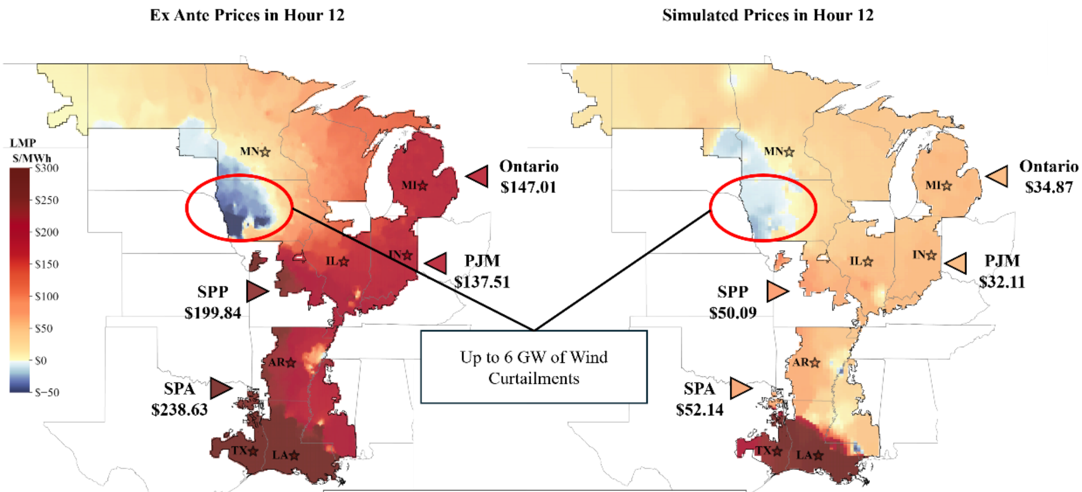
Market Repricing Issues in October

In September, we identified a software issue related to the TLR process. After investigating it, MISO found that the issue affected TLR limits in the market for 8 days. MISO repriced the market under its Continuing Error provisions in 19 hours affected by the error. On October 9, 2025, the effects of MISO's repricing were large because forced outages in MISO South compounded the TLR error. In this and previous instances, MISO used a price substitution methodology that copied prices from the interval before the error was introduced and used them for the duration of the event.

In hour 12 on October 9, the TLR modeling error caused six GW of wind to be curtailed. Forced outages of a nuclear unit and a coal steam unit (1400 MW) in the South during the same hour led to high prices and prompted a large increase in imports. MISO's repricing methodology wiped out the appropriate price signals reflecting reserve shortages. We collaborated with MISO to determine appropriate pricing for this hour and other affected periods by using our market simulation software to re-solve the market software for the impacted intervals with only the TLR-related error correction. Our alternative approach, shown in Figure 14, preserved the market impacts of the generation loss and indicated that some of the wind curtailed inadvertently because of the TLR error likely would still have been curtailed.

8 A competing constraint occurs when a unit provides relief on one constraint by increasing its output while causing severe binding on the other constraint.

Figure 14: Impacts of IMM Repricing Methodology
October 9, 2025 in Hour 12



Hub	Ex Ante Price	Simulated Price	Difference
AR	$237.54	$85.27	-$152.27
IL	$148.53	$55.25	-$93.28
IN	$177.04	$61.62	-$115.42
LA	$462.48	$357.20	-$105.28
MI	$173.87	$61.67	-$112.20
MN	$27.91	$22.32	-$5.59
TX	$383.77	$270.74	-$113.03

Repricing issues that affect dispatch prices and settlements throughout MISO harm the integrity of the market because participants respond to prices in real time. Changing prices retroactively can harm the market participants that were relying on MISO's posted prices, including the importers that were responding to the high real-time prices. Additionally, retroactive repricing is not likely to be accurate because it does not account for the different decisions participants would have made if the updated values had been visible. Therefore, we recommend that MISO mitigate re-settlement harm by limiting repricing to localized errors. When repricing is warranted, we recommend that MISO rerun its market software to produce prices that are as accurate as possible, reflecting all system conditions at the time.

III. Future Market Needs

The MISO system is changing rapidly as its resource fleet transitions and new technologies enter the market. These changes require MISO to adapt to new operational and planning needs. In addition, the long period of low load growth appears to be ending. MISO now projects compound annual load growth of over two percent for the next 20 years, which will steadily increase capacity needs.

MISO's markets are well suited to facilitate both the rapid penetration of renewables and sizable load growth, and we expect no fundamental market changes will be necessary. However, several key improvements are critical as MISO proceeds through these changes, some of which have been implemented or are underway. Three critical improvements we have recommended include:

1. *Efficient Shortage Pricing*. This is critical for compensating the resources needed to maintain reliability in markets with growing operational uncertainties. It also provides critical incentives for resource availability and performance. MISO responded to this recommendation by improving its contingency reserve demand curves to base it on value of lost load of $35,000 per MWh and capped at $10,000 per MWh for deep shortages.
2. *Marginal Capacity Accreditation*. We recommended aligning capacity accreditation with resources' reliability contributions to ensure that MISO continues to have a portfolio of resources with the attributes needed to maintain reliability over the long term. MISO developed a marginal accreditation framework consistent with this recommendation that will be implemented for the 2028–2029 Planning Year.
3. *Reliability-Based Capacity Demand Curves.* We recommended for fifteen years that MISO establish capacity requirements (demand) that correspond to the marginal reliability value that capacity provides. This ensures that MISO procures an efficient level of capacity in the short term and sets prices that will facilitate efficient investment and retirement decisions in the long term. MISO implemented an RBDC in 2025 that has already fundamentally improved capacity pricing and long-term price signals.

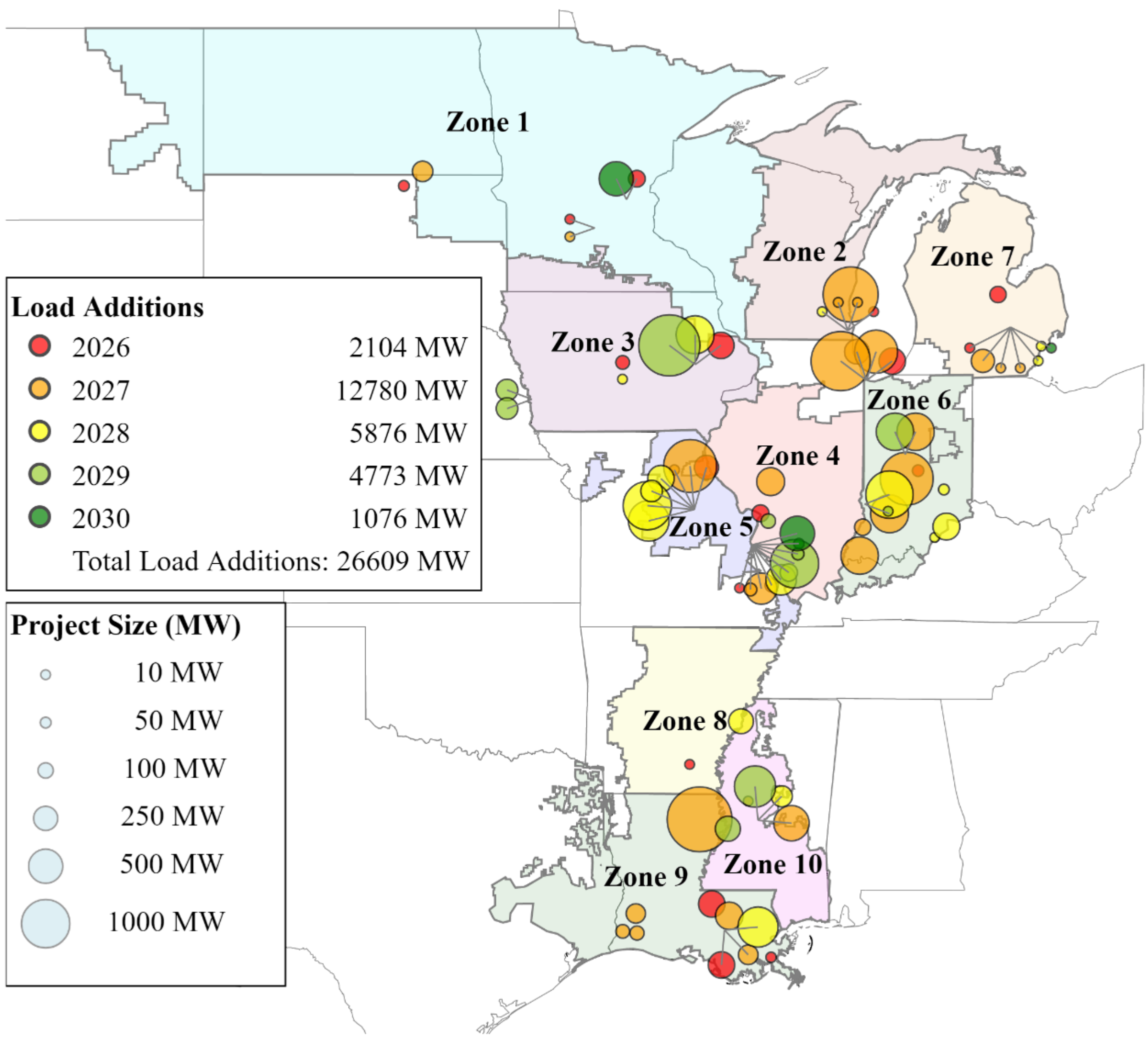
These fundamental reforms are essential for MISO to successfully navigate the substantial changes that lay ahead. However, key challenges remain that we discuss in this section, including the significant changes in MISO's load growth in the coming decades. We also identify the remaining improvements we recommend to address these challenges.

A. Future Demand in MISO

While recent years have focused on the clean energy transition underway in MISO on the supply side, significant changes are now anticipated on the demand side. MISO has evaluated substantial electrification of the transportation sector from widespread adoption of electric vehicles. At the same time, large data centers and other industrial loads are entering more rapidly. MISO projects load additions of over 16 GW by the end of 2027 and an additional 11.5 GW by the end of 2030 based on projects submitted in the MTEP Expedited Process Review.[9] These additions, along with electrification of buildings and transportation, have contributed to the increase in the projected compound annual growth rate (CAGR) over the next five years from 2.2 percent in 2025 to between 3.1 and 5.1 percent in 2026 reported in the OMS-MISO Survey. These changes will substantially affect load profiles and congestion patterns.

Figure 15 shows the large load additions expected over the next few years based on public announcements and projects from MISO Subregional Planning Meetings. These large loads are in addition to demand growth from electric vehicles and heating, and total over 26 GW of additional demand over the next five years.

Figure 15: Expected Load Additions in MISO



9 As reported in MISO Long-Term Load Forecast whitepaper, December 2024, and Large Load Additions Workshops, January and April 2026.

Data centers constitute the vast majority of these new large loads, followed by industrial facilities in the steel, oil refining, semiconductor, mining, and other sectors. Many of these loads are able to provide demand response services, which should drive growth in the demand response resources discussed in Section IX.

Improvements in MISO's capacity market will help facilitate the investment needed to serve these loads reliably, but MISO may confront significant transmission issues. These issues are leading to larger transmission investments through MISO's MTEP process. However, some of these loads may need to be served on a non-firm basis pending the upgrades.

MISO is working through the stakeholder process to evaluate whether "Zero-Injection Generator Interconnection Agreements" ("ZGIAs") may facilitate large loads coming onto MISO's system. ZGIAs would allow developers to build generation near large loads to serve them without obtaining full interconnection rights for the generation. Generators with ZGIAs would be able to serve the load, but not to inject additional energy. Generators that participate in this process may also seek normal interconnection rights. The ZGIA process will facilitate large load additions in the near term before transmission upgrades are in place to fully integrate the new load.

The industry continues to determine requirements for large loads.[10] In our role as IMM, we provided MISO comments on principles and important considerations related to the development of rules and processes for connecting large loads. While we believe MISO's working group has reasonable objectives, we encouraged it to focus on five principles:

1. *Large loads should pay charges equivalent to other loads*: resource adequacy costs and requirements and transmission charges should be comparable for all loads.
2. *The interconnection process should evaluate transmission needs separately for the loads and generation:* co-located load and generation configurations should not obscure the distinct reliability concerns raised by interconnecting the load and the generation. This is particularly important when they produce or consume independent of each other.
3. *Market design should provide dynamic incentives that reflect the system impacts and characteristics of the large loads.* Given how rapidly large loads' consumption can change, increasing the temporal alignment between consumption and settlements through 5-minute real-time settlements or other approaches would promote efficient outcomes. Likewise, cost-causation principles should be applied to cost allocations and other charges that account for system impacts of large loads, both positive and negative.
4. *MISO must have a workable mechanism to cover large loads' Resource Adequacy obligations in the first year they enter:* it must ensure that Resource Adequacy obligations for large loads are met upon interconnection to avoid reliability risk or cost shifting.

10 https://www.nerc.com/globalassets/our-work/guidelines/reliability/white-paper---assessment-of-gaps.pdf Assessment of Gaps in Existing Practices, Requirements, and Reliability Standards for Emerging Large Loads, March 2026.

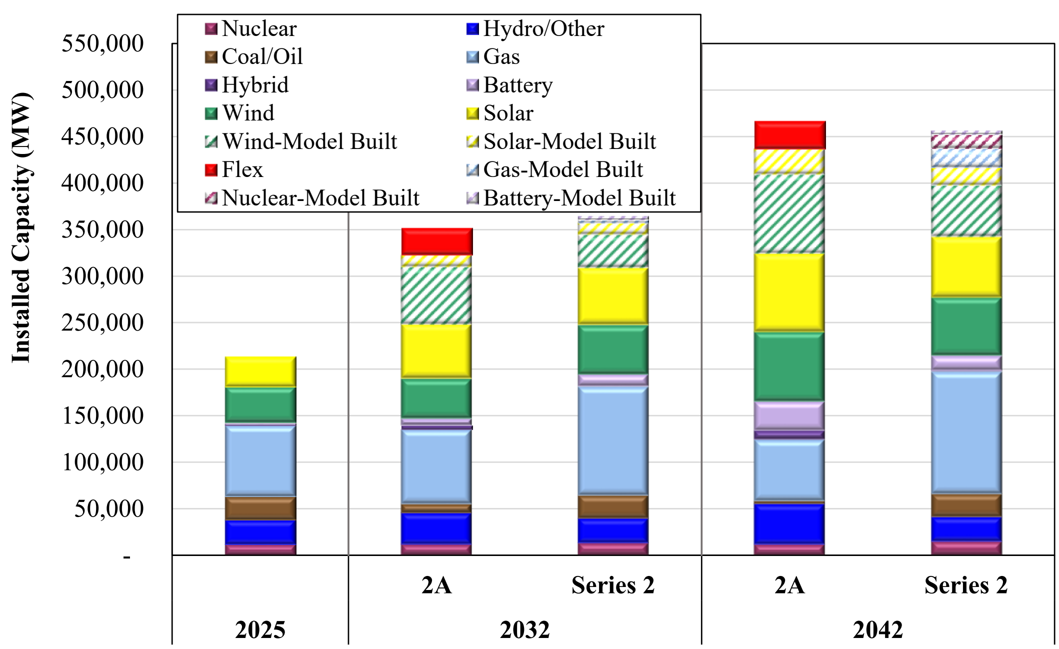
B. MISO's Future Supply Portfolio

In addition to load growth, the resource mix also determines future market needs. In recent years, wind and solar penetration in MISO has consistently increased as baseload coal resources have retired. To date, MISO has effectively managed the operational challenges of integrating intermittent resources while conventional dispatchable resources retire. However, these challenges will continue to increase.

MISO has approximately 1,100 active projects in the interconnection queue, totaling about 220 GW. About 35 percent are solar projects, 21 percent are battery storage projects, 13 percent are wind projects, and 9 percent are hybrid solar and battery projects.[11] Distributed energy resources may also grow and play a larger role in the future. In recent years, members have realized that reliability will require the attributes provided by dispatchable resources, which the new DLOL accreditation rules clearly indicate. Participants have responded by adding more than 32 GW of new gas resources to the interconnection queue.

Figure 16 shows MISO's anticipated resource mix under its prior Future 2A and updated Series 2 Futures scenario.[12] Figure 16 shows wind and solar resources planned by the states in solid bars and wind and solar resources projected by MISO's capacity expansion model in striped bars. Flex resources are unnamed resources that MISO added to Future 2A after it was originally produced to meet energy adequacy needs.

Figure 16: Anticipated Resource Mix: 2032 and 2042



11 See: https://www.misoenergy.org/planning/resource-utilization/GI_Queue/. Data downloaded Feb. 3, 2026.

12 See: MISO Futures Report. Future 2 was published 2021 and Future 2A in 2023.

These Future 2 cases are the primary cases used to determine the transmission portfolios. Figure 16 shows that MISO's forecasts have changed considerably in the three years since it published Future 2A (2023). We find the updated Series 2 future to be a substantial improvement overall.

We raised concerns in the prior process that Future 2A was unrealistic, over-building intermittent renewable resources and underbuilding dispatchable resources. To illustrate our concerns, we developed an alternative case that accepted the member planned additions but modified the resources predicted by MISO's capacity expansion model. This alternative future lowered costs by $88 billion compared to MISO's Future 2A, satisfied the States' carbon goals, and met MISO's energy adequacy needs. The new Series 2 forecast is very similar to the IMM's modified Future 2A scenario and we find it much more realistic. The changes in the new Series 2 reflect:

- Significant shifts in MISO member plans that consistent with the incentives provided by MISO's recently-approved DLOL capacity accreditation – much higher levels of dispatchable resources and much lower levels of renewable resources; and
- Higher forecasted load because of investment in data centers throughout the region.

We have two remaining concerns regarding the current Futures cases. First, MISO does not model affordability factors and cost provisions or "off-ramps" in the States' decarbonization legislation. This is significant because affordability is an increasingly important issue for MISO's customers and modeling these factors could substantially affect the investment and retirement decisions MISO is forecasting.

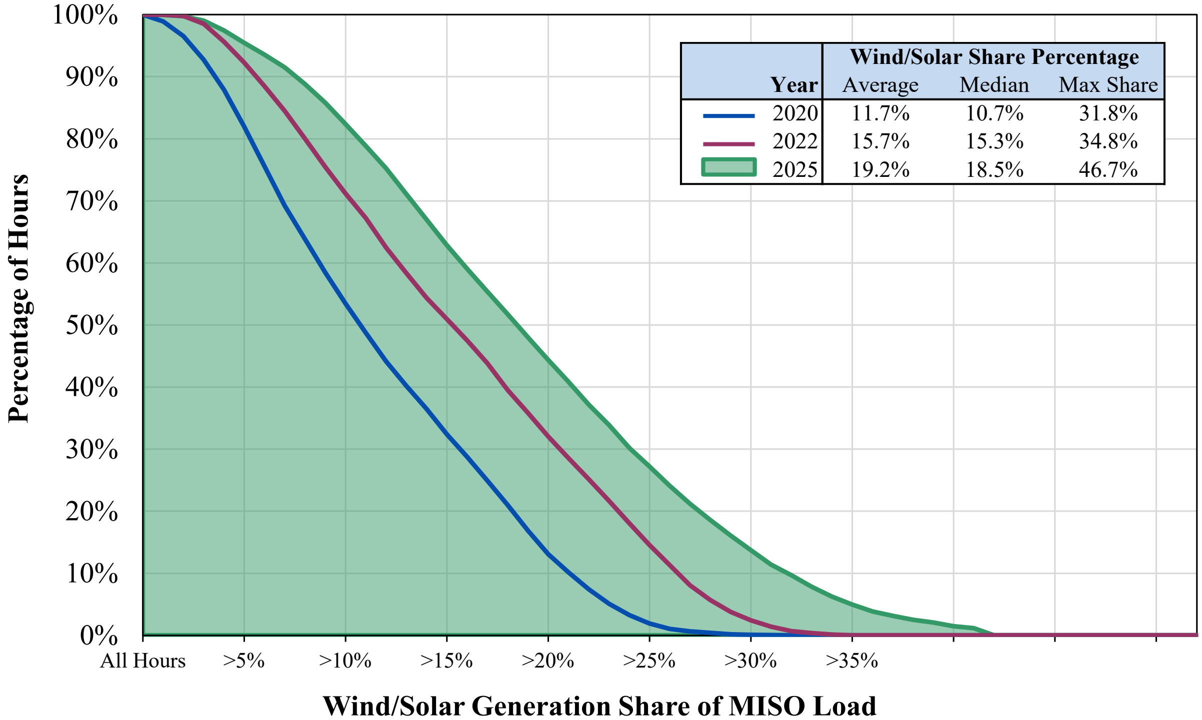
Second, MISO's capacity expansion model seems to under-value storage resources, which results in less entry of battery resources than suggested by current trends in MISO and other markets. Because storage resources are extremely flexible, they can significantly affect perceived transmission needs. We encourage MISO to evaluate potential improvements in energy storage in future planning processes.

Expansion of Wind and Solar Resources

MISO's clean energy transition began with large-scale investment in wind resources and now includes rapid growth in solar penetration. Almost all of MISO's solar resources entered the market during the past five years. In 2025, average hourly wind and solar output grew by about 14 percent to 14.6 GW and supplied about 19 percent of all energy.

Wind and solar generation often vary substantially from hour to hour, but solar typically follows a more predictable pattern. Together, intermittent renewable resources serve an increasing share of load in MISO. Figure 17 shows the cumulative share of MISO load served by wind and solar and how that share has changed over the past six years. The x-axis represents the percentage of load served by wind and solar. The y-axis shows the percentage of hours during the year when renewable output exceeded that share of load.

Figure 17: Share of MISO Load Served by Wind and Solar Generation

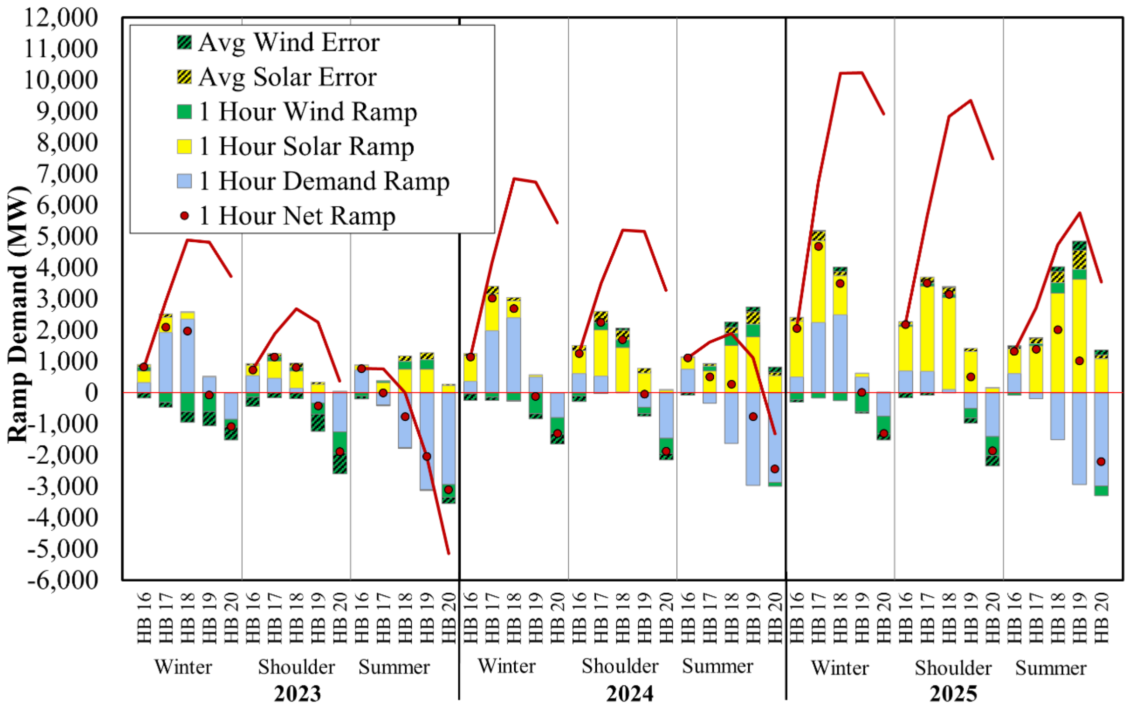


This figure shows that renewable output as a share of load in MISO grew substantially between 2020 and 2025. Renewable resources served more than 19 percent of load on average across all hours and almost 47 percent in the highest-share hour. Because of the proposed projects in the interconnection queue, we expect renewable output to continue increasing in the coming years, led by greater solar penetration. Therefore, MISO will need to continue addressing the operational challenges associated with the already high penetration of renewable resources on its system, some of which are described below.

Renewable Energy Output Fluctuation. Managing renewable generation poses operational challenges because its output is substantially uncertain. Much of this uncertainty results from errors in forecasting wind and solar output. These errors tend to occur in hours when wind or solar output changes rapidly. In 2025, wind output peaked at just over 26 GW in December, and these high output levels resulted in large output fluctuations. For example, intraday renewable output fluctuations exceeded 10 GW on 135 days in 2025.

Because of the operating profile of solar resources, conventional resources must satisfy the system's evening ramping needs. For example, as solar output falls in the evening in the winter months, load is typically increasing to the second peak load of the day. This can place great stress on the conventional generating fleet to meet this ramp demand, particularly if wind output is also falling. One metric that measures demand on conventional generation is "net load", or load minus renewable energy output. Figure 18 shows the average and cumulative net load ramp, and the contributing factors, over the evening hours by season for the last three years. In winter, solar output typically drops as load increases, causing a high net load ramp that thermal generation must meet.

Figure 18: Net Load Ramp in MISO



Since 2023, the cumulative net load ramp shown in the figure above as the total change in net load compared to hour beginning 16 has doubled in the winter season. The evening net load ramp will continue to grow in the foreseeable future as additional solar comes on the system. In 2025, the highest solar output of 14.5 GW occurred in September. Since the beginning of 2026, a new solar output record of 18.7 GW occurred in late April.

Uncertainty. Although sunrise and sunset are predictable, forecasting solar output accurately has been difficult and errors have often been large, particularly during morning and evening hours. Evening net load ramp uncertainty is likely to grow in the future. This creates operational challenges and has led to more frequent contingency reserve shortages during net load ramp periods. In addition, MISO continues to experience periods when intermittent output is close to zero. This underscores the importance of having sufficient dispatchable and flexible resources available to satisfy system demands when intermittent generation is unavailable, ramps down rapidly, or behaves differently than MISO's forecasting models predicted.

Transmission Congestion Caused by Renewable Resources. In addition to the issues caused by output uncertainty, the concentration of many of these resources has created growing network congestion in some periods that can be difficult to manage. This challenge increases when renewable resources do not follow dispatch instructions. Renewable resources that are marginal for managing a constraint through curtailment are often economically indifferent between curtailing and losing production tax credits or not curtailing and paying the prevailing LMP, which will equal their offer price. To address this concern, we recommended dispatch deviation penalties based on the congestion component at resources' locations to ensure they have clear incentives to curtail when instructed. MISO filed penalty provisions in February 2026.

System Support by Renewables. Traditional synchronous generators inherently produce and absorb reactive power, which is critical for voltage regulation across the system. As renewables displace these generators, the system loses a key source of dynamic and steady-state voltage support. Although inverter-based resources (IBRs), including renewable resources and energy storage, can provide reactive power through their inverters, this capability is often underutilized or unavailable. If renewable resources enter at weak network locations, they can reduce voltage regulation and stability in those areas. Additionally, some IBRs may trip offline during transient voltage dips, exacerbating the voltage recovery problem. MISO is addressing these issues by requiring new renewable resources to provide reactive power capability and voltage regulation and imposing automatic voltage control obligations.

Distributed Energy Resources

Distributed Energy Resources (DERs) are an emerging issue for MISO. MISO has been discussing the challenges these resources are expected to pose, especially regarding visibility into and uncertainty about their operation. DERs will generally be located and operated on the distribution system, yet FERC has ordered that DERs can participate in all aspects of the RTO markets, which creates challenges for the RTO.[13]

According to the 2025 OMS DER Survey, 16.7 GW of DERs currently exist in MISO. Of this total, 42 percent is solar, 35 percent is demand response, and the remainder consists of other DER types, including battery storage and small-scale generation. Although we do not anticipate rapid DER entry, MISO should be prepared because technologies and business models can change rapidly. DERs present the following unique challenges for MISO's markets and operations:

- *Operational Visibility*: The output level and location of DERs may be uncertain in the real-time market, leading to challenges managing network congestion and balancing load.
- *Operational Control*: Unlike conventional generation, most DERs will not be controllable on a five-minute basis. This affects how MISO can integrate DERs into market operations.
- *Economic Incentives*: If DERs participate in or are affected by retail rates, they may face inefficient incentives to develop and operate.

13 Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators, Order No. 2222, 172 FERC ¶ 61,247 (2020).

MISO is engaging stakeholders to identify the technical, market, and reliability issues associated with alternative DERs. As MISO develops new market rules and processes, it should ensure that DERs support reliability and create efficient incentives for DERs and non-DERs. To meet these goals, we recommend that MISO adopt the following objectives:

- *Comparable and Verifiable Performance*. DERs participating in energy markets should have comparable performance and verification requirements to other types of units.
- *Distinguish Between Controllable and Uncontrollable*. DERs that are not controllable (e.g., rooftop solar, energy efficiency) present additional forecasting challenges and do not support reliability in the same manner as controllable DERs.
- *Operate and settle locationally*. MISO's operations and settlements must reflect the locational effects of DERs to provide efficient investment incentives and use them effectively. Therefore, accurate locational metering will be essential.
- *Avoid Duplicative Payments*. In many cases, DERs will already participate in non-wholesale markets or distribution programs. Duplicative payments create inefficient investment and operating incentives and should be avoided if possible.
- *Develop accurate accreditation methods for DERs*. Most DERs will be less accessible and controllable than conventional resources. Accurate accreditation is essential to incentivize investment in DERs and other resources needed for reliability.

Energy Storage Resources

Order No. 841 required MISO to enable Energy Storage Resources (ESRs) to participate in the market while recognizing their operational characteristics. By the end of 2025, 26 ESRs were participating in MISO with about 1,300 MW. Figure 16 above shows that MISO forecasts only moderate ESR growth over the next decade.

Based on trends in other markets and the resources in MISO's interconnection queue, we believe this forecast is conservative. ESR installation costs should fall as they proliferate, and their economic value should grow as intermittent-resource penetration increases. This is particularly true because MISO has improved its shortage pricing and now efficiently compensates ESRs for the value they provide in mitigating or eliminating transitory shortages.

ESRs can provide tremendous value by reliably managing fluctuations in intermittent output. However, ESRs are not fully substitutable for conventional generation, especially as ESR quantities rise and their marginal value falls. Therefore, MISO should adopt an accurate accreditation methodology for ESRs, as we discuss in the following subsection.

C. The Evolution of the MISO Markets to Satisfy MISO's Reliability Imperative

MISO has reliably managed the growth in intermittent resources. Some have suggested that dramatic generation portfolio changes require fundamental changes in MISO's markets, but this is *not* true. MISO's markets are robust and well-suited to facilitate this transition, although they will require improvements. MISO has been making the necessary changes to accommodate higher levels of intermittent resources, including:

- Introducing a ramp product to increase the dispatch flexibility of the system;
- Developing the DIR capability to improve control of wind resources;
- Implementing the Short-Term Reserve Product and dynamically adjusting the requirements to manage uncertainty;
- Reforming shortage pricing to compensate resources that are available, flexible, and able to help MISO maintain reliability when shortages arise;
- Reforming capacity accreditation so that resource capacity credits under Module E accurately reflect reliability values; and
- Introducing a seasonal capacity market with reliability-based demand curves aligned with the marginal reliability value that capacity provides.

These reforms are essential because they improve system operations and more efficiently compensate the dispatchable resources needed to balance the uncertain and often volatile output of the rapidly growing fleet of intermittent resources. However, as the resource fleet transitions, additional operational issues will arise. MISO can address most of these issues through three key market improvements:

- Introduce an uncertainty product that reflects MISO's need to commit resources to maintain sufficient supply in real time to manage uncertainty; and
- Implement a look-ahead dispatch and commitment model in the real-time market.
- Introduce new processes to optimize transmission system operations and improve utilization; and
- Improve transmission planning processes and benefit-cost analyses.

The following subsection discusses these improvements.

1. Improvements in the Energy and Ancillary Services Markets

Energy and ancillary services markets will be key to the transition to a cleaner generation portfolio because they will ensure that MISO fully utilizes its supply and demand resources to maintain reliability efficiently while providing critical incentives that govern resource development and operation. The following are key improvements in this area.

Uncertainty Product

As MISO transitions to a fleet that depends far more on intermittent resources, supply uncertainty will increase markedly and affect MISO's planning and operations. MISO has correctly concluded that the availability and flexibility of its non-intermittent resources will be paramount to maintaining reliability. MISO often commits resources outside the market to ensure sufficient generation is available to respond to uncertainty, resulting in RSG costs. A market product that reflects these needs would allow prices to reflect them efficiently, reduce MISO's out-of-market actions, and eliminate the associated RSG costs.

As intermittent generation increases, these operational needs and out-of-market costs are likely to rise substantially. Hence, we recommend that MISO develop an uncertainty product for the day-ahead and real-time markets to account for growing uncertainty associated with load, intermittent generation, NSI, and other factors. In 2024, MISO began to address uncertainty by dynamically raising its short-term reserve requirements, a 30-minute product. This is a positive change, but resources need not start within 30 minutes to address uncertainty. Hence, the uncertainty product could allow resources with longer lead times, e.g., two to four hours, to sell the product. It would also allow MISO's prices to reflect the need for this capacity, reduce RSG, and reward the flexible resources that can meet this need.

Look-Ahead Dispatch and Commitment

Over the longer term, we also recommend that MISO implement a look-ahead dispatch and commitment model to optimize the dispatch of resources over multiple future dispatch intervals spanning an hour or more. Sharp increases and decreases in net load (load minus intermittent output) will create extreme ramp needs for the remaining dispatchable resources, which could be as high as almost 40 GW in three hours because of the amount of solar resources coming online. Although MISO can manage these ramp demands in a variety of ways, most would require costly out-of-market intervention by operators. Therefore, we believe MISO must implement a look-ahead dispatch and commitment model to optimize:

- Dispatching slower-ramping resources that may need to begin ramping 15 to 30 minutes before a sharp increase in net load or during periods of increased uncertainty;
- Committing intra-day resources that can start in ten minutes to two hours; and
- Utilizing storage resources, DERs, and resources with energy limitations.

Optimizing resource commitment and dispatch will reduce the costs of managing net load fluctuations and the uplift costs that would otherwise likely be considerable. As the penetration of intermittent and storage resources increases, these benefits will grow, and look-ahead dispatch capability will become increasingly critical to meeting the system's reliability needs.

2. Improvements in the Operation of the Transmission System

As intermittent output grows and transmission-flow variability increases, critical bottlenecks are likely to emerge. These bottlenecks will increase congestion and lead to higher levels of output curtailments. Therefore, maximizing transmission-network utilization and facilitating efficient transmission upgrades will be key. MISO's work with transmission owners to submit ambient-adjusted and emergency ratings is the first essential step toward greater network utilization, and other key improvements are discussed below.

One of MISO's core functions is ensuring that the transmission system can reliably support the MISO markets. The accelerating growth of renewables will create new challenges, partly because large fluctuations in intermittent output can substantially change transmission flows. These fluctuations can cause erratic congestion patterns that are more difficult to forecast. Options to address these challenges include technologies and processes that allow MISO to optimize network operations by redirecting flows to minimize congestion or by using dynamic line ratings for transmission facilities that account for factors other than temperature.

These technologies may enable large cost savings with little or no impact on reliability. These technologies are known as "grid-enhancing technologies" (GETs), and the processes are known as "grid optimization." In addition to reducing congestion, these processes and technologies may improve MISO's ability to plan for and manage transmission and generation outages, as well as flow fluctuations caused by load and intermittent generation. To realize the benefits of these technologies and process improvements, MISO will need to devote resources in the coming years to integrating them into its operations and systems.

D. Conclusions

As the MISO system continues to change substantially, the markets must support and facilitate those changes. Over the past three years, MISO has proposed or implemented key improvements to its capacity and energy markets. We recommend the remaining changes needed to navigate this clean energy transition successfully: a) implementing a real-time look-ahead dispatch and commitment model, b) introducing an uncertainty product, and c) improving the transmission planning process.

IV. Energy Market Performance and Operations

MISO's electricity markets operate in a two-settlement system that clears in the day-ahead and real-time timeframes. The day-ahead market is financially binding and establishes one-day forward transactions for energy and ancillary services.[14] The real-time market clears based on physical supply and demand, settling deviations from day-ahead schedules at real-time prices.[15] The performance of both markets is essential. The day-ahead market is essential because:

- Most resources in MISO are committed through the day-ahead market, so good market performance is essential to ensure their efficient commitment;[16]
- Most wholesale energy bought or sold through MISO's markets is settled in the day-ahead market—99 percent in 2025 (net of virtual transactions); and
- Day-ahead market outcomes determine the value of entitlements for firm transmission rights (i.e., payments to FTR holders are based on day-ahead congestion).

Real-time market performance is also crucial because it governs the optimal physical dispatch of MISO's resources and establishes prices that indicate the real-time value of energy and ancillary services. These prices send economic signals that facilitate day-ahead market scheduling and longer-term investment and retirement decisions. This section evaluates day-ahead and real-time market performance and operations in key areas.

A. Day-Ahead Prices and Convergence with Real-Time Prices

Day-ahead energy prices tracked the real-time price trends described in Section II and rose as natural gas prices increased. Average day-ahead energy prices increased 43 percent from 2024 to almost $43 per MWh. Congestion caused average day-ahead prices at MISO's hubs to range from $33 per MWh at the Arkansas Hub to roughly $44 per MWh at the Indiana Hub.

An important difference between the day-ahead and real-time markets is that the day-ahead market clears hourly schedules, while the real-time market clears every five minutes. This creates challenges in managing MISO ramp demands, i.e., the need to schedule generation to rise or fall as load and other conditions change over the day. Because large supply changes tend to occur at the top of the hour when day-ahead schedules change, prices tend to spike at these times. In December 2024, MISO implemented a ramp requirement floor to procure sufficient ramp capability to mitigate these issues until it implements a longer-term solution. We

14 In addition to day-ahead market commitments, MISO utilizes the Multi-Day Forward Reliability Assessment Commitment process to commit long-start-time resources to satisfy reliability needs in certain load pockets.

15 In addition, deviations that are due to deratings or outages are subject to allocation of uplift payments. Virtual and physical transactions scheduled in the day-ahead market are also subject to these charges.

16 After the day-ahead market, MISO runs its Forward Reliability Assessment Commitment (FRAC) and Look-Ahead Commitment (LAC) process that may cause MISO to make additional commitments.

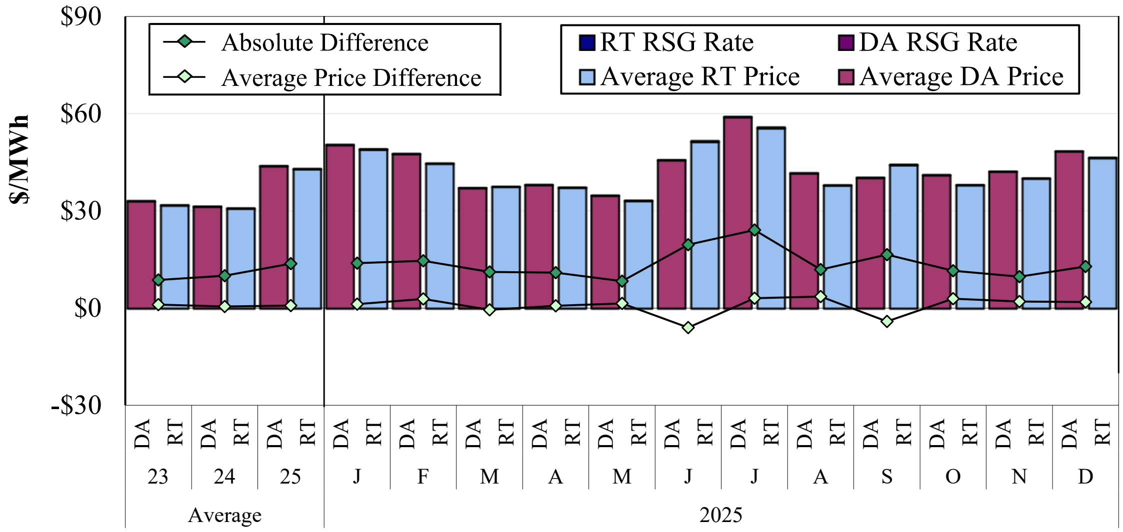
previously recommended that MISO evaluate the feasibility of transitioning to a 15-minute day-ahead market, but MISO determined that this is not currently feasible.

The primary measure of day-ahead market performance is how well day-ahead prices converge with real-time prices. The real-time market clears physical supply and demand, and participants' day-ahead bids and offers should reflect their expectations of market conditions on the following day. However, several factors can cause real-time prices to differ significantly from day-ahead prices, including wind or load forecast errors, real-time output volatility, and forced generation or transmission outages. Although these factors may limit convergence in a well-performing market on an hourly basis, prices should converge over longer timeframes (monthly or annually).

Figure 19 shows monthly and annual price convergence statistics. The upper panel shows monthly average prices plus allocated RSG costs at Indiana Hub. Real-time RSG charges, which are allocated partly to real-time deviations from day-ahead schedules, tend to be much larger than day-ahead RSG charges, which are allocated to day-ahead energy purchases. The lines show two measures of the difference between day-ahead and real-time prices. The bottom table shows the average percentage difference between day-ahead and real-time prices for six hub locations in MISO, accounting for allocated RSG costs.

Figure 19: Day-Ahead and Real-Time Prices at Indiana Hub

2023–2025



Average DA-RT Price Difference Including RSG (% of Real-Time Price)

Indiana Hub	3	2	2	2	6	-1	2	4	-12	5	9	-9	8	5	4
Michigan Hub	3	0	0	0	5	-2	3	5	-12	3	9	-11	1	4	3
Minnesota Hub	-1	-1	2	3	12	-3	-2	2	-11	4	6	-11	23	10	3
Arkansas Hub	2	1	3	10	3	5	12	10	-1	-2	6	-12	3	3	-2
Louisiana Hub	4	1	-4	10	-2	3	1	-29	1	-5	7	-16	6	4	4
Texas Hub	4	1	2	10	-1	4	-5	14	-1	-3	6	-11	9	5	6

These results indicate good overall price convergence. After adjusting for real-time RSG costs, averaging $0.16 per MWh, day-ahead prices were about two percent higher than real-time prices.

B. Virtual Transactions in the Day-Ahead Market

Virtual transactions provide a large share of the liquidity that facilitates good day-ahead market performance. They are financial purchases or sales of energy in the day-ahead market that do not correspond to physical load or resources. Virtual buyers (or sellers) enter the real-time market long (or short). Because they do not produce or consume physical energy, their positions settle at real-time prices. Virtual transactions are essential to price convergence because they arbitrage differences between the day-ahead and real-time prices. Figure 20 shows the average offered and cleared virtual supply and demand for financial-only participants and physical participants.

Figure 20: Virtual Demand and Supply in the Day-Ahead Market
2025

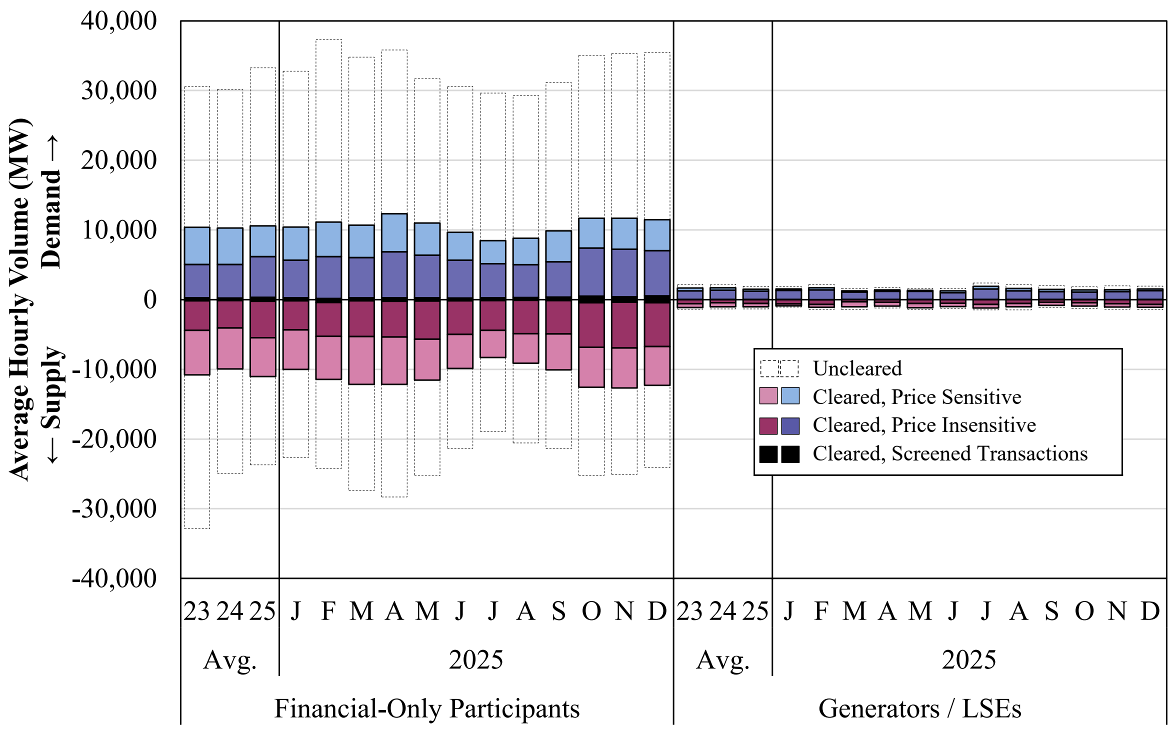


Figure 20 shows that financial participants continue to account for the vast majority of virtual transactions, while the limited quantities scheduled by physical participants fell roughly 9 percent from 2024. Key findings and trends include:

- Cleared transactions increased by five percent, rising comparably in both subregions;
- Financial participants submit offers more price-sensitively, which provides liquidity in the day-ahead market.
- Several participants submit "backstop" bids and offers that are priced well below (for demand) or above (for supply) the expected price range. Backstop bids and offers clear less than one percent of the time, but they are substantially profitable when they do clear. They are beneficial because they mitigate particularly large day-ahead price deviations.

- Bids and offers that are price-insensitive (i.e., offered at prices making them very likely to clear) are a large share of all transactions and provide less liquidity to the market.
  - Participants use most price-insensitive trades to arbitrage congestion-related price differences by establishing an energy-neutral position between two locations (offsetting virtual supply and demand trades). We call these "matched" transactions.
  - Matched transactions avoid RSG deviation charges and carry no energy price risk. Their average hourly volume increased by 13 percent from 2024 to 1,694 MW.
  - We continue to recommend that MISO implement a "virtual spread product" that would allow participants to engage in these transactions price-sensitively which would be more efficient—comparable products exist in PJM and ERCOT.
- Price-insensitive transactions that cause congestion *divergence* between the day-ahead and real-time markets (labeled "Screened Transactions") raise potential manipulation concerns. They were only 2.6 percent of all transactions and raised no concerns in 2025.

Virtual Activity and Profitability

Gross virtual profitability rose 33 percent in 2025 to average $0.59 per MWh, up from $0.45 per MWh in 2024. In 2025, virtual demand profitability dropped sharply from $0.39 to negative $0.30 per MWh, while virtual supply profitability grew from $0.51 to $1.49 per MWh. In general, gross profits are higher for virtual supply because real-time RSG costs allocated to participants with net virtual supply positions offset more than 20 percent of these profits. Virtual demand does not bear capacity-related RSG costs because it reduces the need for real-time capacity commitments. Virtual transactions by financial participants remained more profitable than those submitted by physical participants, averaging $0.66 per MWh compared to $0.06 per MWh. This is likely because physical participants may be using them to hedge real-time risks.

Table 2 provides perspective on virtual trading in MISO by comparing it to trading in NYISO, ISO New England, SPP, and PJM.

Table 2: Comparison of Virtual Trading Volumes and Profitability

2025	Virtual Load		Virtual Supply	
Market	**MW as a % of Load**	**Avg Profit**	**MW as a % of Load**	**Avg Profit**
MISO	15.5%	-$0.30	15.5%	$1.49
NYISO	6.1%	$3.39	7.7%	$1.25
ISO-NE	4.5%	-$3.19	8.0%	$2.67
SPP	11.6%	$1.80	16.7%	$3.60
PJM	5.9%	$1.01	6.0%	$1.24

Table 2 shows that virtual trading is generally more active in MISO than in most other RTOs, even after adjusting for MISO's much larger size. This is partly because of MISO's more efficient allocation of RSG costs. The table also shows that the liquidity from virtual trading in

MISO translates to relatively low virtual profits. Gross virtual supply profits are higher than virtual load profits because of the RSG cost allocation discussed above.

Low virtual profitability is consistent with an efficient day-ahead market, which is important because it coordinates the daily commitment of MISO's resources. Although overall profitability is a positive indicator, the next subsection analyzes virtual transactions in more detail to determine the share that improves day-ahead market outcomes.

Benefits of Virtual Trading

We studied how virtual trading contributed to market efficiency in 2025. Efficient virtual transactions generally lead to convergence between the day-ahead and real-time prices and were profitable. A small share of the efficiency-enhancing virtual transactions are unprofitable. This occurs when virtual transactions over-converged the congestion differences. Profits from un-modeled constraints or loss factors are not efficiency-enhancing because these profits do not increase day-ahead efficiency so we refer to these profits as "rent seeking".

Inefficient virtual transactions led to divergence and were generally unprofitable based on energy and congestion on modeled constraints. However, they can be profitable because of un-modeled constraints or loss factor differences. Table 3 shows the amount of efficient and inefficient virtual transactions by market participant type. Section IV.G of the Analytic Appendix describes our methodology in detail.

Table 3: Efficient and Inefficient Virtual Transactions by Type of Participant in 2025

Transaction Category	Financial Participants			Physical Participants		
	MWh	Convergent Profits	Rent-Seeking	MWh	Convergent Profits	Rent-Seeking
Efficiency Enhancing (Profitable)	93,583,084	$1,513.8M	-$38.9M	9,830,352	$145.0M	-$2.8M
Efficiency Enhancing (Unprofitable)	14,313,700	-$127.6M	$27.7M	1,701,087	-$13.6M	$2.3M
Not Efficiency Enhancing (Profitable)	5,993,685	-$37.3M	$87.6M	626,260	-$2.7M	$5.5M
Not Efficiency Enhancing (Unprofitable)	75,396,812	-$1,320.2M	$19.1M	9,769,483	-$135.0M	$2.5M
Total	**189,287,281**	**$28.8M**	**$95.5M**	**21,927,181**	**-$6.3M**	**$7.6M**

The table shows that 57 percent of all virtual transactions enhanced efficiency. All virtual transactions produced net positive convergent profits of $22.5 million. However, this amount significantly understates the net benefits of virtual transactions because it measures profits at the margin. In other words, the total benefit is much greater than the marginal benefit because

- The profits from efficient virtual transactions decrease as prices converge; and
- The losses of inefficient virtual transactions get larger as prices diverge.

Although we cannot rerun the day-ahead and real-time market cases for the entire year, this analysis provides strong evidence that virtual trading was beneficial in 2025.

C. Real-Time Market Pricing

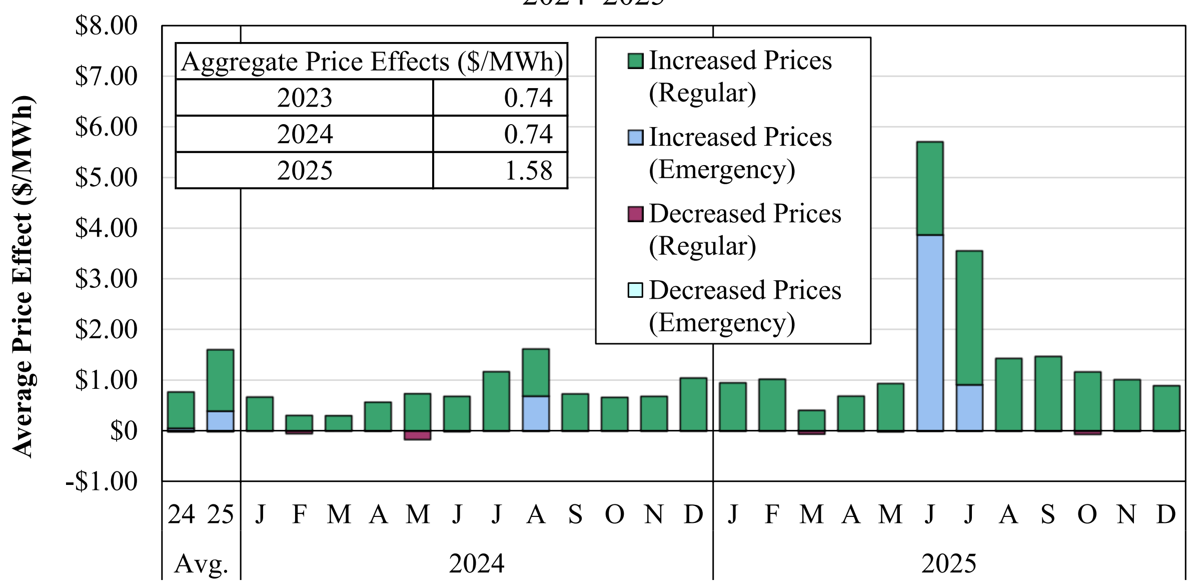
Efficient real-time market outcomes are essential because they incentivize suppliers to be available and respond to dispatch instructions. They also inform forward price signals for day-ahead scheduling and long-term investment and maintenance. In this subsection, we evaluate whether real-time prices efficiently reflect prevailing conditions. However, we do not discuss pricing during energy or reserve shortages here because Section III addresses it in discussing the future needs of the MISO markets. Efficient shortage pricing is essential for market performance, especially as reliance on intermittent resources rises.

Fast-Start and Emergency Pricing by the ELMP Model

Beyond shortage pricing, a key element of MISO's real-time pricing is the Extended Locational Marginal Pricing (ELMP) models. While MISO's dispatch model calculates "ex ante" real-time prices every five minutes, the ELMP model recalculates these prices for real-time settlements. ELMP improves price formation by establishing prices that better reflect the true marginal costs of supplying energy and ancillary services at each location. ELMP allows Fast-Start Resources (FSRs) and emergency resources to set prices when doing so is needed and economic to satisfy the system's needs.[17] Figure 21 summarizes the effects of the ELMP model in 2025.

Figure 21: The Effects of Fast Start Pricing in ELMP

2024–2025



% of Intervals Affected by > +/- $0.10

	24	25	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
SMP Increase	51	59	56	44	43	58	50	42	64	52	49	52	51	57	58	47	31	54	57	65	74	63	63	67	63	62
SMP Decrease	1	1	1	0	0	1	1	1	0	0	0	0	0	1	1	0	2	1	1	1	0	1	0	1	1	2

17 Emergency supply is priced by applying a $500/MWh offer price floor (Tier 1) to this supply in ELMP when MISO declares a Max Gen Warning and a $1000/MWh floor (Tier 2) in a Max Gen Event Step 2.

When prices do not efficiently reflect FSRs or emergency resources, the prices are understated, which leads to higher RSG costs and weaker incentives to schedule generation and interchange efficiently. Figure 21 shows that ELMP's effects on real-time energy prices rose by 119 percent in 2025, in part because of more frequent emergency pricing in June and July. ELMP had a small effect in the day-ahead market because supply is more flexible and includes virtual transactions.

Modifying the Market Pricing during LMR Deployments

Although EEA2 events that prompt MISO to deploy LMRs have been rare, pricing during these events has often been inefficient. During emergency conditions, the ELMP model determines whether emergency resources should set prices by attempting to dispatch them down and let other resources replace them. The theory is that if the ELMP model cannot ramp the emergency resources to zero, they are needed and should set real-time prices. Although this is reasonable in most cases, it is not always reasonable for LMRs because they are usually deployed in large quantities (3 to 6 GWs). The ELMP model generally lacks enough ramp capability on conventional resources to replace the LMRs in a single dispatch interval. As a result, LMRs often set prices long after they are no longer needed. This has resulted in:

- Elevated prices extending beyond the emergency area to all of MISO after supply is adequate and the constraint into the area no longer binds; and
- Large uplift payments in the form of price-volatility make-whole payments to resources held down to make room for the LMRs and non-firm imports.

We recommend that MISO revise its emergency pricing model to either reintroduce LMR curtailments as Short-Term Reserves rather than energy demand or to allow for longer ramp capability for other resources to replace the LMRs. This would improve the emergency pricing and better align ex-ante and ex-post results. The STR requirements would expand to include the amount of LMRs scheduled, and the associated demand curve would adjust to reflect the prevailing emergency offer floor price.

D. Uplift Costs in the Day-Ahead and Real-Time Markets

Evaluating uplift costs is important because customers have difficulty forecasting and hedging them, and they generally reveal where market prices do not fully capture the cost of system requirements. Most uplift costs result from guarantee payments to participants. MISO employs two primary forms of guarantee payments to ensure resources cover their as-offered costs and incentivizes them to be available and flexible:

- RSG payments ensure that the total market revenue of a unit committed economically or for reliability equals or exceeds its as-offered costs over its commitment period; and
- Price Volatility Make-Whole Payments (PVMWP) ensure that suppliers are not financially harmed by following five-minute dispatch signals.

Resources committed before or in the day-ahead market may receive a day-ahead RSG payment to recover their as-offered costs. Resources that MISO commits after the day-ahead market receive a real-time RSG payment to recover their as-offered costs. Day-ahead RSG costs for economic commitments are recovered on a pro-rata basis from all scheduled load. Real-time RSG costs are recovered through charges to participants that cause them, and the residual is charged to load. This allocation creates efficient incentives for participants.

Day-Ahead and Real-Time RSG Costs

Figure 22 shows monthly day-ahead RSG costs by underlying cause—i.e., to manage congestion or meet capacity needs. Most VLR commitments occur before or during the day-ahead market process so they produce day-ahead RSG costs, shown in the maroon bars. Because fuel prices strongly influence suppliers' production costs, the figure shows RSG payments in both nominal and fuel-adjusted terms.[18] The blue portion of the bars shows RSG incurred for commitments made to maintain system-wide capacity.

Figure 22: Day-Ahead RSG Payments

2024–2025

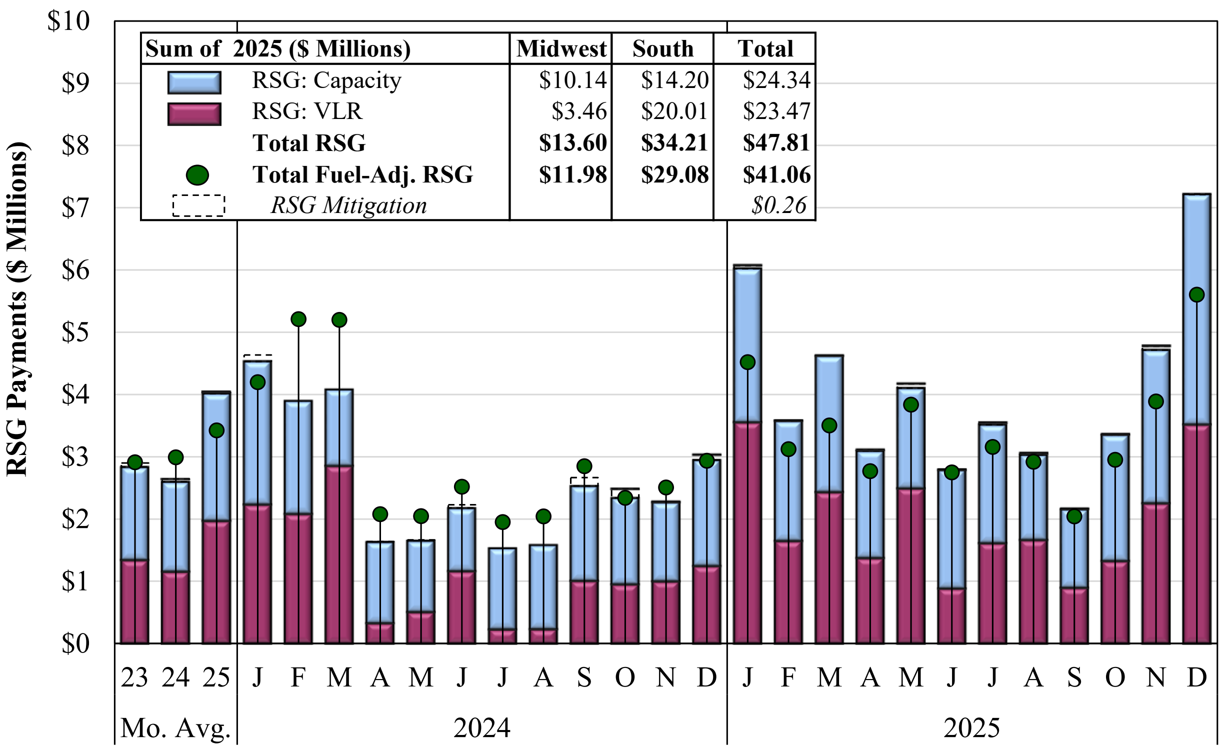


Figure 22 shows that nominal day-ahead RSG payments rose 55 percent in 2025 to $47.8 million, generally in line with year-over-year increases in gas prices. Units in MISO South received 58 percent of day-ahead capacity-related RSG payments and 85 percent of day-ahead

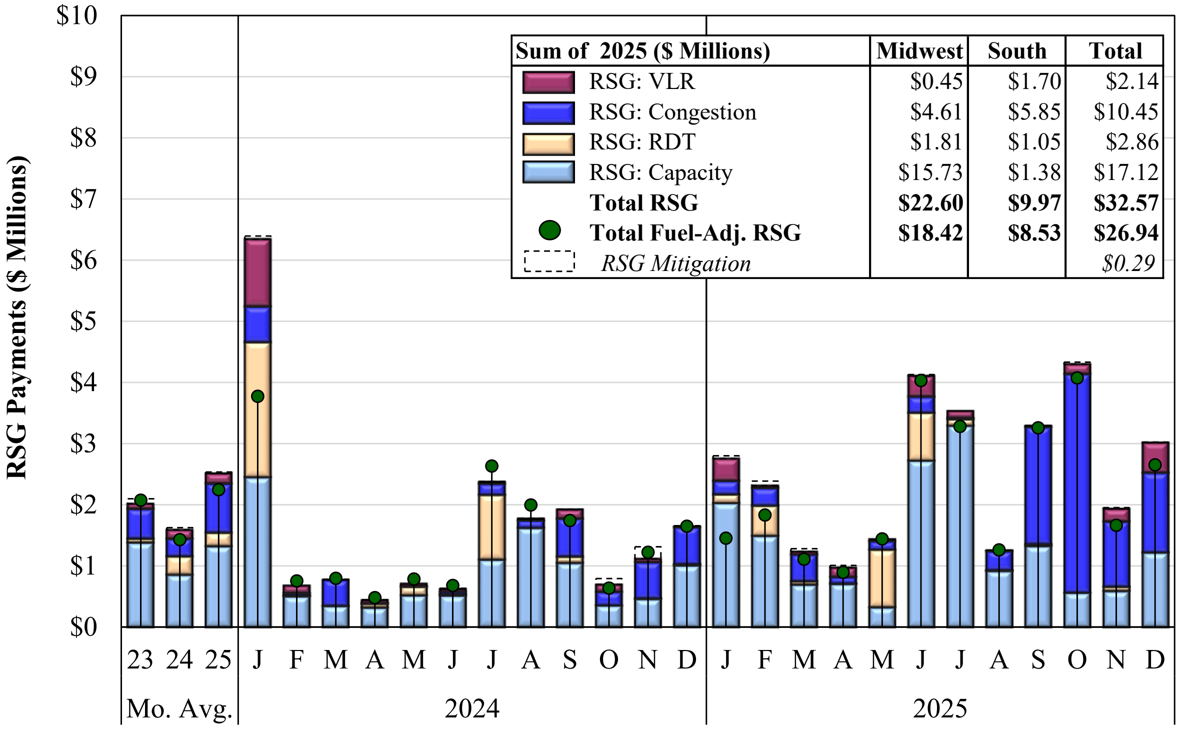
18 Fuel-adjusted RSG payments are indexed to the average three-year fuel price of each unit.

voltage RSG payments. Likewise, higher gas prices contributed to a 58 percent increase in real-time RSG payments along with a single expensive unit repeatedly committed in MISO South to manage congestion in September and October. These commitments were based on a transmission study, even though the constraint that prompted the unit's commitment never bound. We recommend that MISO validate outage study results in the real-time operating timeframe to ensure such commitments are efficient and necessary.

Although real-time RSG rose in 2025, significant improvements in MISO's commitment processes since 2021 have generally lowered RSG overall. In our prior reports, we raised concerns that many out-of-market commitments that produced real-time RSG costs were not necessary to meet MISO's real-time reliability needs. This was a key concern because excess real-time supply tends to lower and distort real-time prices, raise RSG, and weaken the incentive to fully schedule resources in the day-ahead market.

Figure 23: Real-Time RSG Payments

2024–2025



We recommended several improvements, and MISO worked closely with us to implement many of them, including (i) increasing STR requirements to address uncertainty rather than committing resources, (ii) eliminating the headroom requirement in LAC, (iii) lowering the operating reserve demand curves in LAC to better align with those used in the markets, and (iv) deferring commitments that need not be made immediately because of resources' start-up times. These changes substantially improved MISO's commitment processes and mitigated the adverse effects of out-of-market commitments on real-time prices and costs.

Price Volatility Make-Whole Payments

PVMWPs address concerns that resources may be harmed by responding to volatile five-minute price signals. These payments incentivize suppliers to offer flexible physical parameters. They take two forms: Day-Ahead Margin Assurance Payments (DAMAP) and Real-Time Offer Revenue Sufficiency Guarantee Payments (RTORSGP). Resources receive DAMAP when they produce less than both the day-ahead schedule and the economic output level implied by the offer price. Resources receive RTORSGP when a unit operates above its economic output level. Table 4 shows annual DAMAP and RTORSGP totals, along with price volatility at the system level (SMP volatility) and at the unit locations receiving the payments (LMP volatility).

Table 4: Price Volatility Make-Whole Payments ($ Millions)

	DAMAP		RTORSGP		Total	Market-Wide Volatility	Locational Volatility
	Midwest	South	Midwest	South			
2025	$43.0	$11.6	$3.1	$0.6	$58.3	18.5%	21.2%
2024	$44.8	$8.1	$3.4	$0.6	$56.8	20.9%	26.7%
2023	$35.8	$3.3	$3.8	$0.8	$43.7	15.5%	21.0%

PVMWPs increased 2.5 percent from 2024. An increase in ancillary services shortages caused more frequent price spikes in 2025, causing DAMAP to generators in these periods to more than double from 2024. Additionally, the RDT was violated less frequently in 2025, which causes subregional prices to rise by up to $500 per MWh, which can contribute to DAMAP for slower-moving resources. DAMAP from RDT-related price spikes decreased by 70 percent in 2025.

E. Real-Time Dispatch Performance

MISO issues dispatch instructions to generators every five minutes that specify expected output at the end of the next five-minute interval. Good generator performance is essential to managing congestion efficiently and maintaining reliability in MISO. Therefore, MISO's markets must provide adequate incentives for generators to follow dispatch instructions. Failure to meet a dispatch instruction is known as "dragging". It can be measured in each 5-minute interval or summed over a longer period (e.g., 60 minutes). Table 5 shows the average 5-minute dragging and 60-minute average hourly dragging in recent years, excluding renewable resources, for all hours and for hours when generation must ramp up or down rapidly in the morning and evening.

Table 5 shows that 60-minute dragging in all hours has remained relatively flat from 2024 to 2025 although it increased in the worst 10 percent of hours. Dragging is a substantial concern because capacity from resources that do not follow dispatch instructions is effectively unavailable to MISO. Some of these 60-minute deviations may indicate units that are derated and physically incapable of increasing output. Because participants must report derates under the Tariff, we referred the most significant "inferred derates" to FERC enforcement. Additionally, this conduct can qualify as physical withholding when no physical cause for the derate exists.

Table 5: Average Five-Minute and Sixty-Minute Dragging (MW)
2021–2025

	5-min Deviation Net		60-min Deviation Net		Worst 10%	
	Ramp Hours	All Hours	Ramp Hours	All Hours	Ramp Hours	All Hours
2025	(59)	(83)	(82)	(28)	226	174
2024	(129)	(149)	(96)	(26)	193	153
2023	(96)	(118)	(87)	(7)	247	182
2022	(218)	(312)	(87)	(11)	229	163
2021	(180)	(255)	(79)	(4)	165	186

Failing to follow dispatch signals has the greatest adverse effects when a resource affects the flows on a binding transmission constraint. The real-time market dispatch produces dispatch instructions and prices that assume the resource will follow those instructions. In recent years, MISO has increasingly experienced significant differences between its setpoint instructions and units' output, particularly for renewable resources.

Current rules allow renewable resources to produce as much output as possible when their dispatch instructions align with the forecast maximum value. The rule reflects that, absent a binding transmission constraint, forecast errors should not limit renewable resource generation. Unfortunately, renewable forecasting errors have led to significant deviations between units' forecasts and actual capabilities, creating challenges in managing unmodeled flows on binding transmission constraints. These findings show the need to improve generators' incentives to follow dispatch instructions and update resources' real-time offers promptly.

Aligning Uninstructed Deviation Penalties with Congestion Impact

Current settlement rules do not adequately penalize generation deviations outside the uninstructed deviation (UD) tolerance bands, and they exempt deviations that persist for less than 20 minutes from any financial penalty. One key penalty is the excessive energy price, which applies the lower of LMP and as-offered cost to excessive energy volumes (such as when a renewable resource fails to curtail output). This creates a very weak incentive, particularly for renewable resources, which often set prices at their cost when curtailed. In these cases, the renewable resource is financially indifferent between following dispatch and producing excessive energy. This indifference is especially harmful when excessive energy causes transmission overloads. We have observed operators taking expensive actions to manage the transmission system in response to wind resources that do not follow dispatch.

This concern will grow as more intermittent resources enter the system, so we recommended revising the penalty structure based on the marginal congestion component (MCC) of the resource's LMP when the resources' deviation is loading a constraint. MISO filed tariff changes in February 2026 to implement this recommendation. This MCC-based penalty will be correlated with the severity of the congestion the deviation causes and ensure resources have an incentive to follow curtailments.

Excess Operating Reserve Payments to Units not Following Dispatch

In addition to improving the incentive to follow dispatch instructions generally, MISO should avoid paying excessive ancillary service payments to units that are deviating so compensation is better aligned with performance. If a resource is unwilling or unable to meet its energy dispatch schedule, the resource would likely not be able to deploy operating reserves when needed.

We have identified many cases where resources sell operating reserves that are not following dispatch instructions. Two notable cases include:

- Resources operating well below their dispatch setpoint over an extended period, but selling substantial quantities of spinning reserves or regulation above this output level; and
- Resources operating above their dispatch setpoints into their operating reserve range when LMPs are substantially higher than their marginal costs and being paid for both energy and operating reserves for the same MWs. This is a gaming strategy.

Figure 24 summarizes the overpayments by product (spinning reserves, STR, and ramp capability up or "RC Up") for the resource types with the largest shares of overpayments—gas and oil-fired resources and coal-fired resources. Although the "Other" category remains relatively small, overpayments to storage resources could grow because their fast ramp rates allow them to sell large quantities of ancillary services. The figure shows the two cases described above, labeled "reserve performance" and "reserves excessive", respectively.

Figure 24: Overpayments for Ancillary Services when Deviating from Dispatch Setpoints
2025

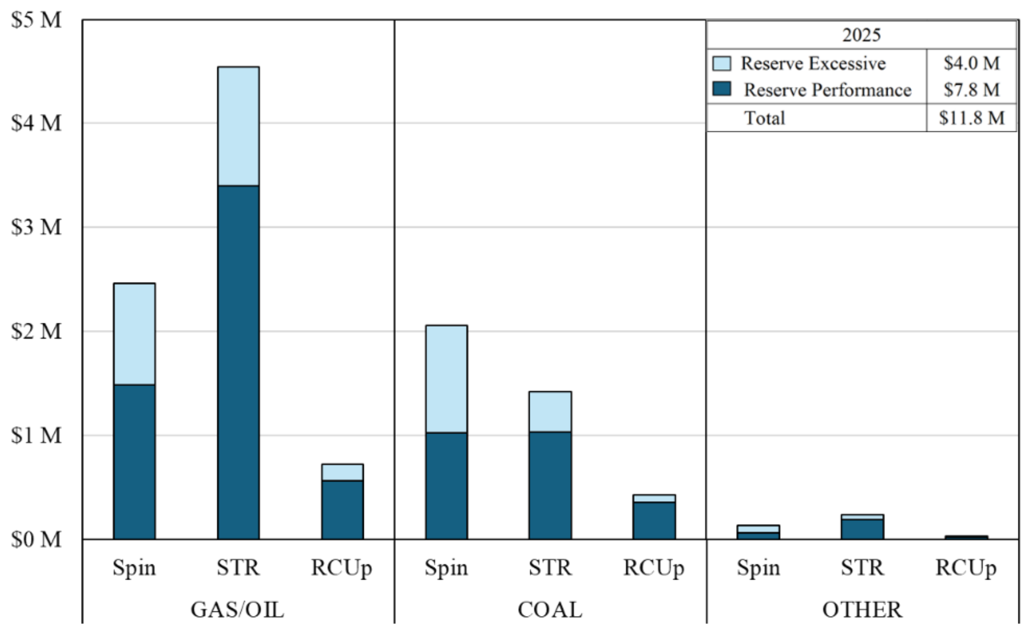


Figure 24 annual payments of $11.8 million in 2025 and these costs have increased in recent years. To eliminate these overpayments, improving dispatch incentives and eliminating the gaming opportunity, we recommend adjusting reserve payments based on the resource's dispatch performance using an approach similar to the methodology applied to PVMWP settlements. Resources that follow dispatch instructions reasonably would receive full reserve compensation, while resources with poor dispatch performance would receive reduced payments. MISO may also consider not scheduling ancillary services on units not following dispatch instructions. In the case of units overproducing, the overproduced energy would be compensated at the LMP as occurs today and the reserve payment would be eliminated for these MWs. Together, these changes would strengthen incentives to follow dispatch instructions and better align market compensation with real-time reliability contributions.

Emergency-Range Performance Penalties

When MISO enters a capacity or transmission emergency, MISO can access the offered emergency ranges of online generators. In recent events, both capacity and transmission emergencies, we have frequently observed generators being dispatched into their emergency ranges but not following MISO's setpoints. Generators have an incentive to overstate the offered emergency maximum dispatch limits because resource accreditation is based on emergency maximum offered availability during the tightest hours.

Currently, no penalties exist for units not providing their emergency output during emergencies or overstating their emergency capabilities, and this bad incentive results in overstated emergency MW, which creates a reliability issue. MISO ratepayers pay capacity resources for their emergency ranges, which may not be just or reasonable if those resources cannot perform in those ranges when the system needs them.

In 2026, MISO filed penalty provisions to provide stronger incentives for LMRs to perform when called upon during emergencies. We recommend MISO implement similar penalties for failure to perform in the offered emergency ranges of online generators since, similar to LMRs, generator emergency ranges are only obligated to perform during declared emergencies.

We estimated the size of the proposed penalties for generating resources that failed to follow dispatch instructions into their emergency ranges based on generator performance during the two most recent capacity emergency days: June 23, 2025 and January 24, 2026. Our analysis applies penalty formulas similar to the penalties for Load-Modifying Resources (LMRs), including both existing Locational Marginal Price (LMP)-based penalties and the Auction Clearing Price (ACP)-based penalties MISO filed with FERC in 2025. It produced that following penalties:

- $5.6 million penalties for emergency ranges on coal resources, which is 27 percent of the capacity payments made for all coal-fired emergency ranges.
- More than $12 million penalties for emergency ranges on gas and oil resources, which is 24 percent of the capacity payments made for all gas and oil-fired emergency ranges.

These penalties ensure that: (1) generation emergency ranges are treated comparably to emergency LMRs, and (2) customers receive the reliability services for which they are paying.

Dispatch Operations: Offset Parameter

MISO real-time operators choose the offset parameter to adjust the modeled load served by the unit dispatch model. A positive offset value is added to the short-term load forecast to increase generation output, while a negative offset decreases load and the corresponding dispatch instructions. Offset values may be needed for many reasons, including: a) generator outages that the model does not yet recognize; b) generator deviations (producing more or less than MISO's dispatch instructions); c) wind output that is over- or under-forecasted in aggregate; or d) operators believing the short-term load forecast is over- or under-forecasted.

Large changes in offset values increase price volatility. This is not surprising because ramp capability—the ability of the system to quickly change output—is often limited. As a result, large offset changes can lead to sharp price changes. Conversely, offset reductions or lower-than-optimal offset values sometimes mute legitimate shortage pricing. We have identified several events in which sub-optimal offset values led to inefficient real-time prices. We are working with MISO to improve its procedures for setting offset values more optimally.

F. Coal Resource Operations

Table 6 summarizes our analysis of coal resource operations, including startup patterns and profitability. The table separately shows these results for regulated and unregulated utilities.

Table 6: Coal-Fired Resource Operation and Profitability

	2020-2023			2024			2025		
	Annual Starts	% of Starts	Net Rev. ($/MWh)	Starts	% of Starts	Net Rev. ($/MWh)	Starts	% of Starts	Net Rev. ($/MWh)
Regulated Utilities	1687		**$9.60**	1428		**$8.01**	1304		**$17.43**
Profitable Starts	1478	88%		1215	85%		1231	94%	
Offered Economically	*757*	*45%*		*672*	*47%*		*513*	*39%*	
Must-Run and profitable	*721*	*43%*		*543*	*38%*		*718*	*55%*	
Unprofitable (Must Run)	210	12%		213	15%		73	6%	
Merchants	101		**$12.16**	39		**$7.50**	38		**$18.37**
Profitable Starts	101	100%		35	90%		38	100%	
Offered Economically	*101*	*100%*		*29*	*74%*		*29*	*76%*	
Must-Run and profitable	*1*	*0%*		*6*	*15%*		*9*	*24%*	
Unprofitable (Must Run)	0	0%		4	10%		0	0%	

Table 6 shows that higher natural gas and energy prices in 2025 led to a higher share of profitable starts for coal resources than in 2024. Their net revenues rose to roughly $18 per MWh on average—materially higher than the 2020–2023 average and the 2024 value. MISO's regulated utilities often continue to operate their units as "must-run" resources regardless of price; in 2025, only 6 percent of must-run starts were unprofitable. In contrast, MISO's unregulated generators offered economically in 76 percent of hours in 2024 and were profitable in 100 percent of their run hours.

G. Wind and Solar Generation

As discussed in Section III.B, wind and solar capacity continues to grow in MISO. Wind now accounts for nearly 32 GW of installed capacity, while solar accounts for over 18 GW, almost double the installed capacity at the end of 2024. Wind and solar produced about 19 percent of all energy in MISO in 2025. Section III.B also discusses the long-term challenges this growth will present and the market enhancements we recommend. This subsection describes key trends in wind and solar output, forecasting, and wind scheduling. Table 7 summarizes wind and solar nameplate capacity, average output, seasonal average output, and 2-hour weighted-average forecast errors.

Table 7: Day-Ahead and Real-Time Wind and Solar Generation

2022–2025

	Nameplate	Avg. Output (GW)			RT Seasonal Avg. Output (GW)			RT Top 5% Hrly Avg. Output (GW)			2 Hr Forecast Error (%)	
	Capacity	RT	DA	%	Jan.-Apr.	May-Aug.	Sep.-Dec.	Jan.-Apr.	May-Aug.	Sep.-Dec.	Avg. Error	Abs. Avg.
2025	49,538	14.6	12.7	-13.1	17.2	12.2	14.3	29.4	27.3	28.2	0.3%	5.6%
*%**	*13%*	*13%*	*11%*		*18%*	*16%*	*7%*	*19%*	*28%*	*14%*		
2024	43,819	12.9	11.4	-11.6	14.6	10.6	13.5	24.8	21.3	24.7	-0.9%	5.6%
2023	35,608	11.1	9.8	-12.0	13.5	8.2	11.8	22.4	18.6	21.8	-1.2%	6.2%
2022	30,916	11.8	10.5	-10.8	14.0	9.1	12.3	21.9	18.8	21.9	-0.2%	6.1%

Note 1: %* Change between 2024 and 2025.

Wind and Solar Output Trends

Average wind output decreased by about three percent from 2024 after increasing in the previous year, while average total wind and solar output increased by 13 percent because of the large increase in solar penetration. The seasonal pattern of wind output continued in 2025—output decreases in the summer months and reaches its highest levels in the spring and fall. However, as solar growth continues to outpace wind additions, we expect average output in the summer months to exceed output in the shoulder seasons.

Wind and Solar Forecasting

The increasing penetration of wind and solar resources has increased the operational challenges of managing ramp demands resulting from the wind output fluctuations described in Section III.B, as well as forecasting errors that arise predictably when the sun sets and solar output falls. Accurate wind and solar forecasts are key to managing these challenges. We produce and use renewable resource forecasts in two key timeframes, which we discuss below:

- Forward forecasts: produced from the day-ahead timeframe up to the operating hour based on wind speed and solar forecasts and other factors; and
- Real-time dispatch forecasts: produced roughly five minutes before the next dispatch interval and generally bases them on current wind output (i.e., a "persistence" forecast).

Forward wind and solar forecasting: Table 7 shows that on high-wind days in 2025, this error averaged about 1,400 MW, and the two-hour-ahead absolute forecast error exceeded 5,200 MW during the last year. On high-solar days, the average absolute error was about 700 MW, with errors up to 3,100 MW. Solar forecasting errors were largest when solar was ramping up or down. These errors can lead to supply shortages and overloads of individual transmission constraints and the RDT interface. Therefore, it is necessary to continue evaluating the causes of relatively large errors and seek improvements in forecasting methodologies and inputs.

Real-time dispatch forecasts: These forecasts must be accurate because they establish wind and solar resources' economic maximums in the real-time market. Because wind and solar units offer at prices lower than other units, forecasted output also typically matches the dispatch instruction, absent congestion. If the real-time forecast is inaccurate, the dispatch model will not accurately model flows on transmission constraints affected by wind and solar resources. This has led to frequent transmission violations and challenges in managing flows over these constraints.

In recent years, MISO improved real-time wind forecasts by reducing the time lag between the most recent output observation and the real-time dispatch model run. In November 2025, MISO improved these forecasts. Wind resources' forecast is the higher of the vendor forecast and the timelier persistence value. MISO's solar forecasts are not as timely and the forecast errors have been larger, which has raised concerns during the evening ramp hours. We recommend that MISO make similar changes to the solar forecasts to make them timelier and more accurate. MISO could likely achieve further improvements by modifying the persistence algorithm to account for how wind resources were moving leading up to the most recent observations.

Wind Scheduling in the Day-Ahead Market

Table 7 shows that wind suppliers generally schedule less output in the day-ahead market than they actually produce in real time. Hourly wind under-scheduling averaged roughly 1,300 MW in 2025. Suppliers' contracts and the financial risks related to RSG cost allocations when day-ahead wind output is overscheduled contribute to this pattern. Under-scheduling can create price convergence issues and uncertainty about the need to commit other resources. Net virtual suppliers partially address this by selling in the day-ahead market in place of the wind suppliers. Because under-scheduling wind in the day-ahead market most significantly affects transmission flows and associated congestion, we evaluated the extent to which virtual transactions offset these flow effects. We found that virtual suppliers made approximately $103 million on 744 wind-impacted constraints, with almost 60 percent occurring on the top 10 constraints. This virtual activity plays a valuable role in facilitating more efficient day-ahead scheduling.

H. Outage Scheduling

Coordination of planned outages is essential to ensure that enough capacity is available if contingencies occur or load is higher than expected. MISO approves planned outages that do not violate reliability criteria, but otherwise does not coordinate them, raising economic and reliability risks. Figure 25 shows outage rates by subregion from 2023 to 2025.

Figure 25: Generation Outages

2023–2025

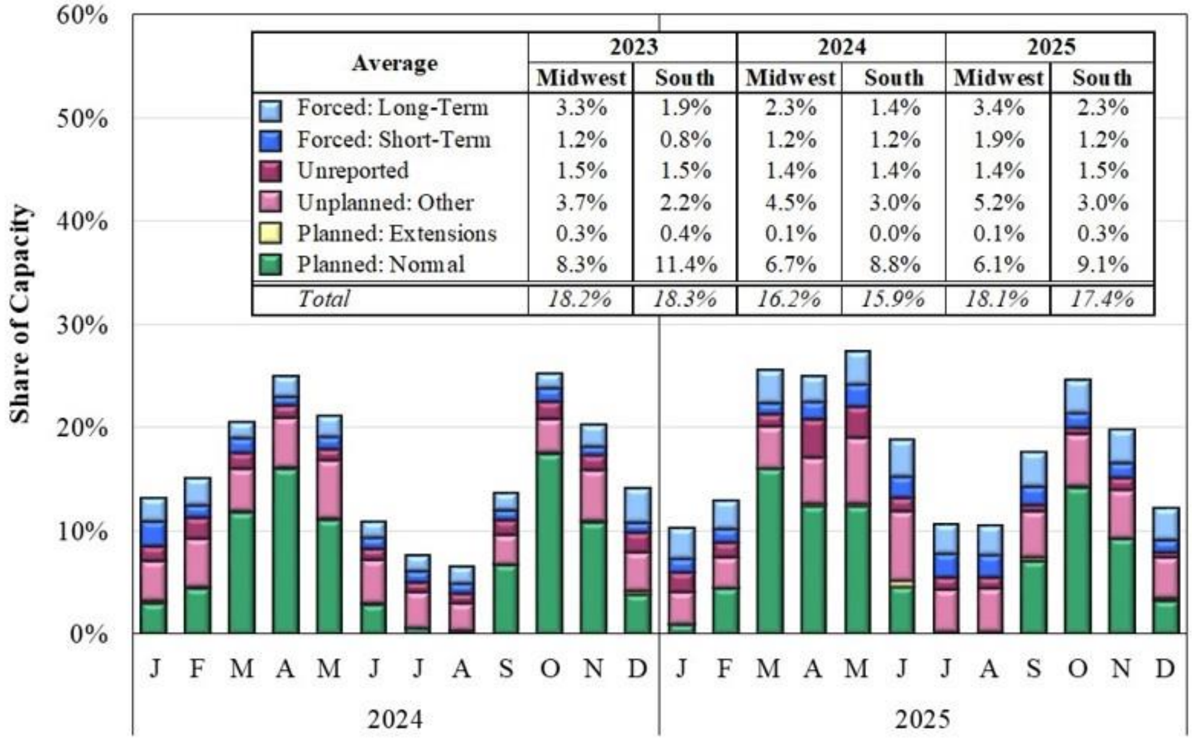


Figure 25 shows that outage rates in 2025 were slightly higher than in 2024. As in prior years, true planned outages were relatively low for most of the summer, although 2025 had more planned outages in June than in 2024. While the overall level of outages does not raise concerns, poorly coordinated outages frequently raise concerns in local areas. In our *2016 State of the Market Report*, we recommended that MISO enhance its transmission and generation planned outage approval authority (see Recommendation 2016-3). We continue to believe that MISO should acquire the authority to deny or postpone outage requests that would create severe congestion or regional shortages. This authority is particularly important because many planned outages are scheduled or extended with very little advance notice. We estimated that $625 million in congestion was attributable to multiple simultaneous planned outages in 2025.

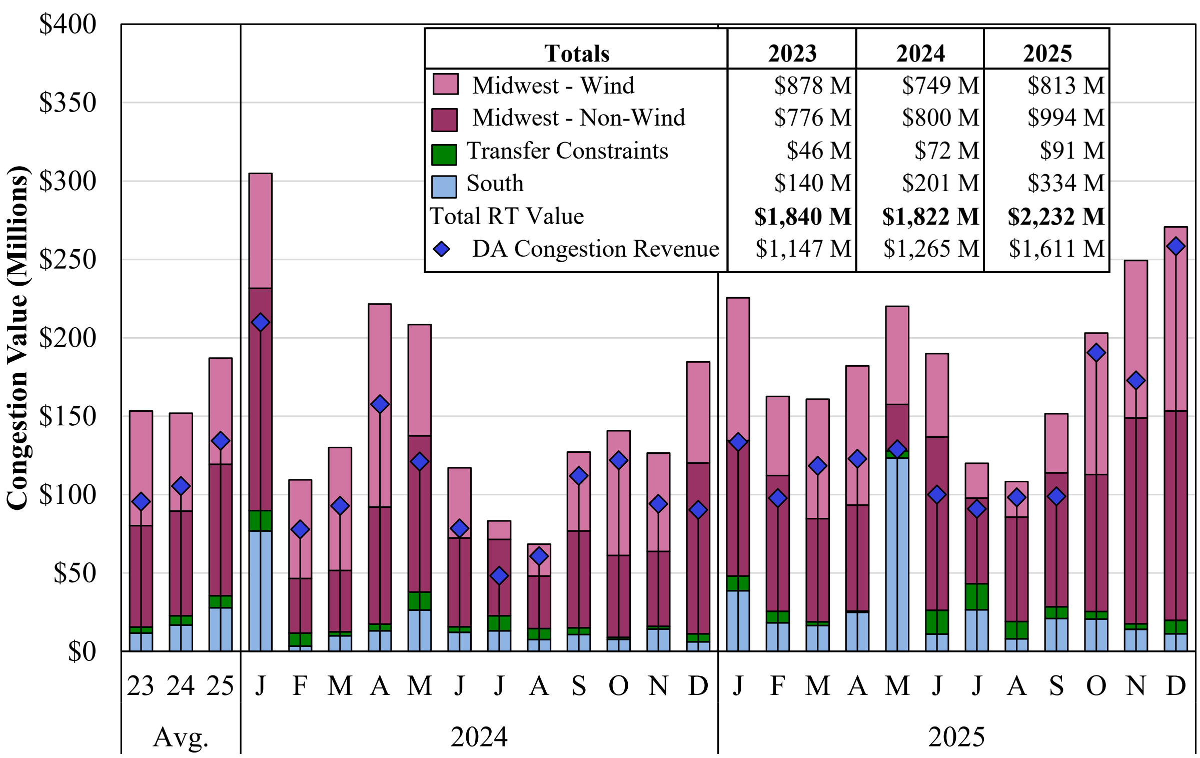
V. Transmission Congestion and FTR Markets

The MISO markets manage power flows over the network to avoid violating transmission constraints by modifying resources' dispatch levels. Transmission congestion arises when network constraints prevent MISO from dispatching the lowest-cost resources to meet demand. The resulting "out-of-merit" costs are reflected in the marginal congestion component (MCC) of LMPs (one of three LMP components). MCCs raise LMPs in "congested" areas where generation relieves constraints and lower LMPs where generation loads constraints. These locational price signals reflect efficient resource dispatch in the short term and help facilitate efficient investment decisions in the long term.

A. Real-Time Value of Congestion in 2025

We calculate the value of real-time congestion as the product of real-time physical flows over each constraint and the constraint's economic value (i.e., the "shadow price"—the production cost savings from relieving the constraint by one MW). This represents the congestion value that arises as MISO dispatches its system. Figure 26 shows the monthly real-time congestion value over the past two years, along with day-ahead congestion revenues.

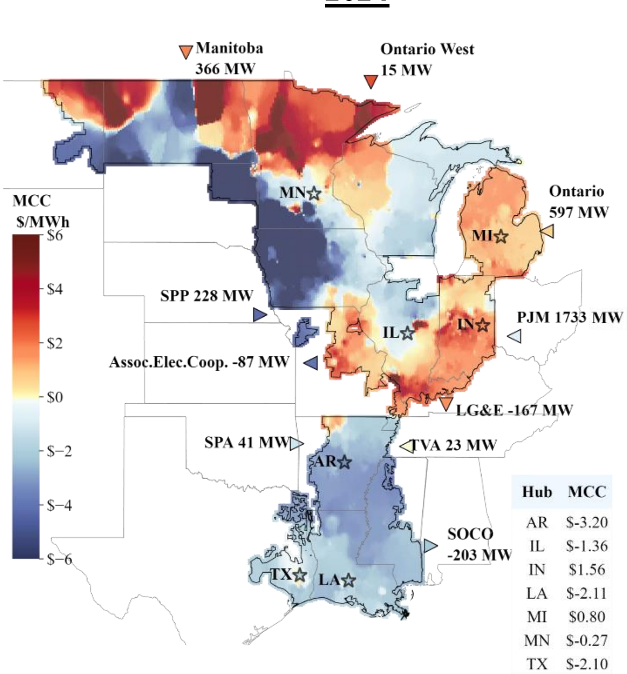
Figure 26: Value of Real-Time Congestion
2024–2025

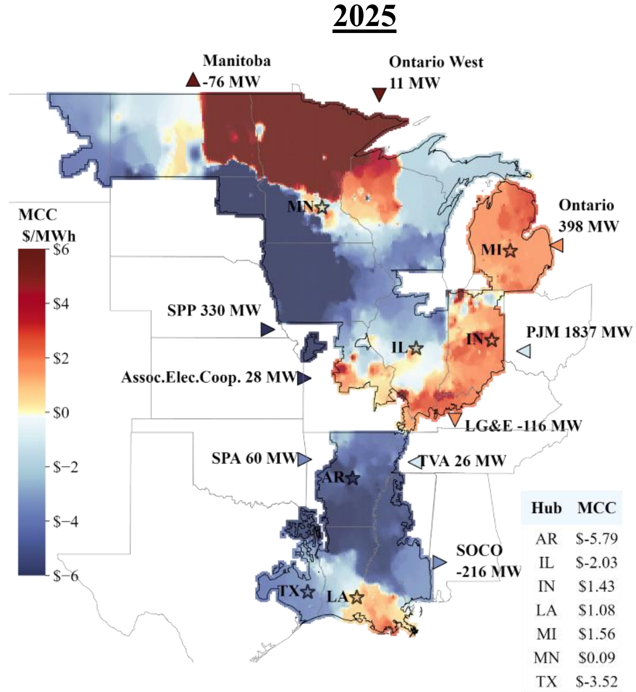


The total value of real-time congestion was $2.2 billion in 2025, a 22.5 percent increase over 2024. Congestion tends to scale with changes in gas prices because gas is on the margin in the majority of intervals. Severe congestion in the South in May resulted from forced and planned generation outages in the Amite South load pocket and, ultimately, a load-shedding event on May 25 to maintain reliability. Congestion was higher in the North region during the fall because some transmission owners did not switch from summer to winter seasonal line ratings until December 1. Although wind-driven congestion rose by 9 percent, it accounted for a smaller share of congestion than in 2024, at roughly 36 percent. Continued expansion of nearby wind resources in SPP and PJM, as well as retirements of dispatchable resources, is likely to increase wind-related congestion in future years.

Figure 27 shows locational differences in the average MCCs of MISO's LMPs in 2024 and 2025. Warmer colors indicate locations where MCCs are positive and increase LMPs, while cooler colors indicate locations where MCCs are negative and lower LMPs. Generally, power flows across MISO from cooler-colored areas to warmer-colored areas.

Figure 27: Average Real-Time Congestion Components in MISO's LMPs





This figure shows changes in congestion patterns in the Midwest region. In 2025, MISO was a net exporter to Manitoba, where continued drought conditions limited hydroelectric generation. Finally, the map shows that the transfer constraint between the Midwest and South bound in more than one quarter of real-time intervals and separated subregional prices by roughly $4.20 per MWh.

B. Day-Ahead Congestion and FTR Funding

MISO's day-ahead energy market is designed to send accurate, transparent locational prices that reflect energy costs, congestion, and losses on the network. In the day-ahead market, MISO collects congestion revenue from load based on differences in the congestion component of the LMPs between where energy is produced and where it is consumed. MISO pays this congestion revenue to holders of Financial Transmission Rights (FTRs), which are economic property rights to power flows over particular elements of the transmission system.

A large share of the value of these rights is allocated to participants based on historical firm use of the transmission network. MISO sells rights to the remaining transmission capability in the FTR market, and this revenue helps recover network costs. FTRs allow market participants to hedge day-ahead congestion costs. If the FTRs issued by MISO are physically feasible, meaning the network flows implied by all FTRs sold do not exceed network capability in the day-ahead market, MISO will always collect enough congestion revenue in the day-ahead market to "fully fund" the FTR entitlements.

This subsection summarizes day-ahead congestion and evaluates two key market outcomes that show how well the network is modeled in the day-ahead and FTR markets:

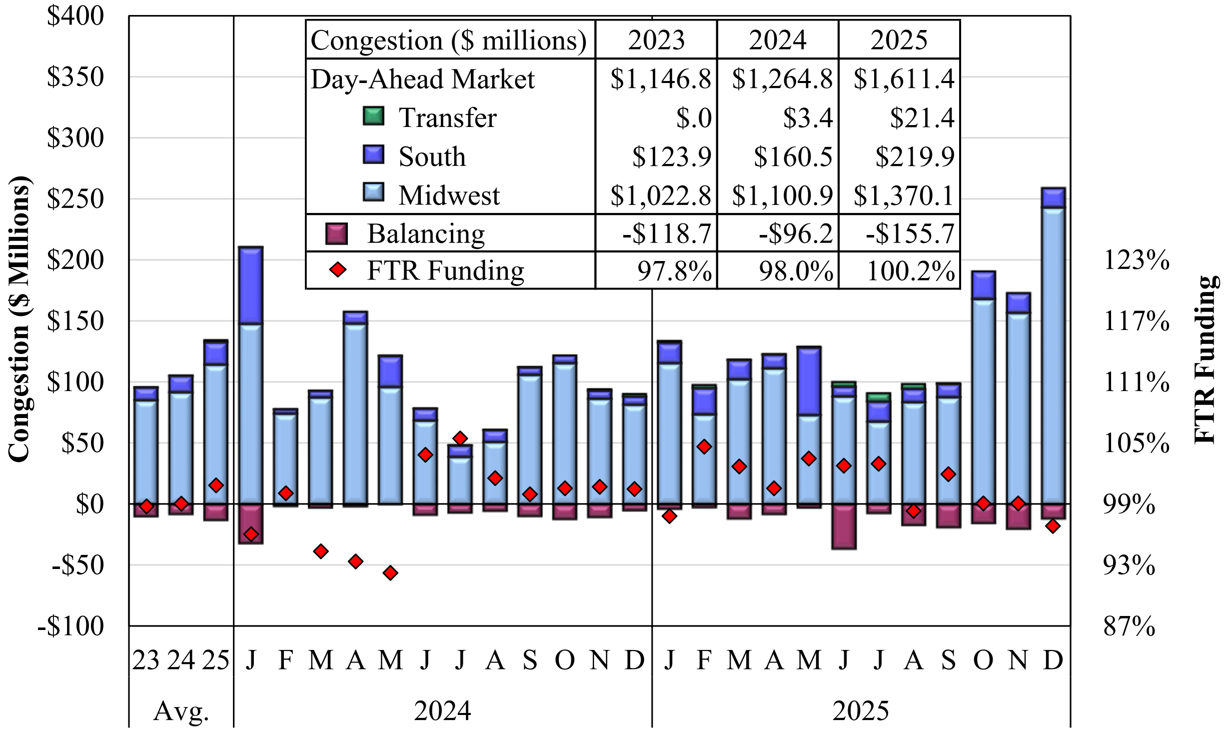
- *FTR Funding*: If MISO does not collect enough day-ahead congestion to satisfy FTR entitlements, FTR funding will be less than 100 percent. This indicates that MISO issued more FTRs than the day-ahead network model could accommodate; and
- *Balancing Congestion*: If day-ahead schedules are not feasible in the real-time market, real-time congestion occurs to "buy back" the day-ahead flows. MISO uplifts the cost to customers as "balancing congestion."

Day-Ahead Congestion Costs

Figure 28 summarizes day-ahead congestion by region and between regions, balancing congestion in real time, and FTR funding levels from 2023 to 2025. Figure 28 shows that day-ahead congestion costs increased by 27 percent to $1.6 billion in 2025, which was 72 percent of the value of real-time congestion on the system. MISO does not collect revenues associated with the full value of real-time congestion because entities that do not settle with MISO cause a large amount of "loop flows." MISO also grants flow entitlements on its system to SPP and PJM that do not pay for congestion up to their entitlement levels. The increase in both day-ahead and real-time congestion is consistent with higher gas prices year over year.

Figure 28 also shows that FTRs were fully funded in 2025, although surpluses in other months offset large shortfalls in January and December. Balancing congestion increased by 62 percent over 2024. The following subsections discuss these two classes of results.

Figure 28: Day-Ahead and Balancing Congestion and FTR Funding
2023–2025



FTR Surpluses and Shortfalls

Discrepancies between the modeling of transmission constraints and outages in the FTR auctions and the day-ahead market cause FTR overfunding and underfunding. For example, a congestion shortfall occurs if flow on a binding day-ahead market constraint is below the flow scheduled in the FTR market. Conversely, a surplus occurs when flow on a binding day-ahead constraint is higher than the flow sold in the FTR market. Funding surpluses also include residual revenues from the FTR auctions.

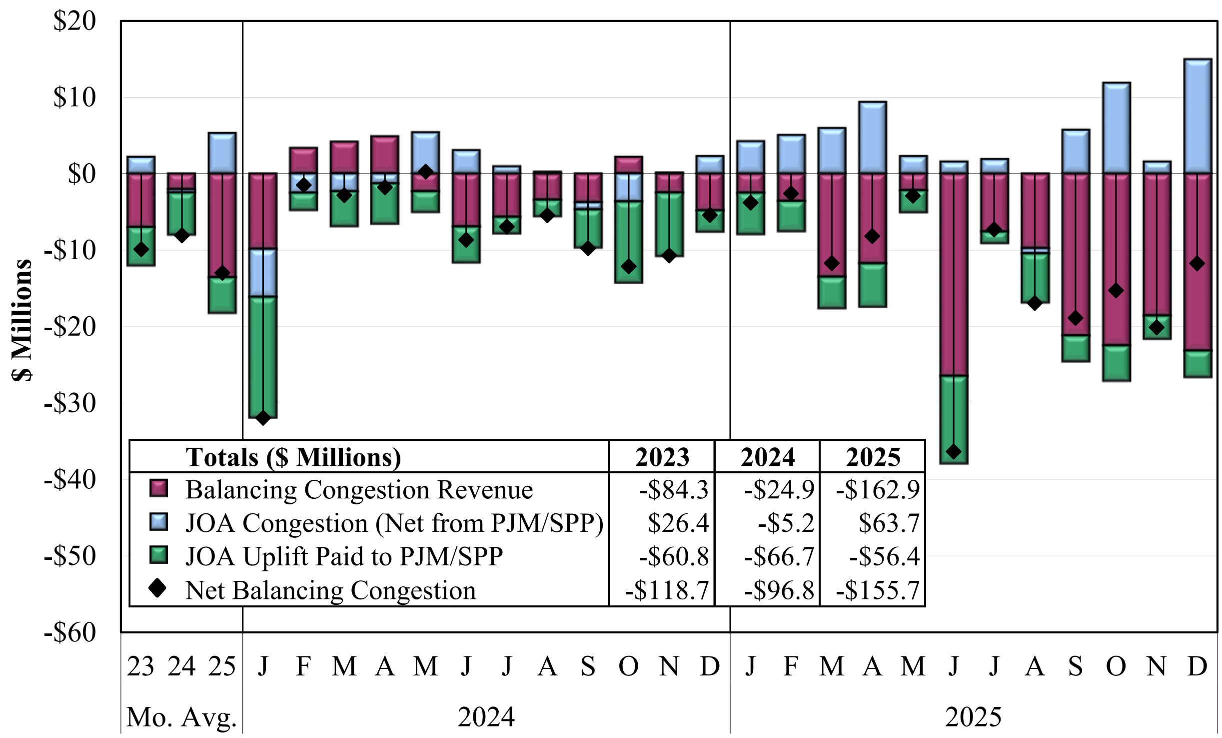
In 2025, day-ahead congestion revenues fully funded FTR obligations. FTRs over the RDT are often overfunded because they can bind in both directions. This bi-directionality causes FTR paths across the transfer constraint to be undersubscribed and generates substantial surpluses when the RDT binds in the day-ahead market. We continue to see significant underfunding periodically on affected be outages because the outages are often not know at the time of the annual FTR auction. Our recommendation to shift some of the capability from this auction to seasonal and monthly auction closer to real time would address this source of under-funding.

Balancing Congestion

Balancing congestion shortfalls (negative balancing congestion revenue) are the costs of redispatching generation to reduce real-time flows on a constraint scheduled at a higher level in the day-ahead market. Conversely, positive balancing congestion occurs when real-time constraints bind at flow levels higher than those scheduled in the day-ahead market.

Large negative balancing congestion costs typically indicate real-time transmission outages or other transmission limit reductions, loop flows not fully anticipated day-ahead, or real-time constraints that bind but were not modeled in the day-ahead market. MISO allocates net negative balancing congestion to load and exports through uplift on a pro-rata basis. While real-time forced outages and derates cannot be eliminated, persistently high negative balancing congestion may indicate day-ahead modeling issues. Accordingly, RTOs should seek to maximize consistency between the day-ahead and real-time market models. Figure 29 shows MISO's monthly balancing congestion costs, including Joint Operating Agreement (JOA) payments to and from SPP and PJM.

Figure 29: Balancing Congestion Revenues and Costs
2023–2025



Net balancing congestion rose by nearly two-thirds in 2025 to negative $155.7 million:

- The sixfold increase in the balancing congestion revenue shortfall from 2024 suggests a significant increase in unanticipated congestion in the real-time market. In June, a single constraint contributed $8 million of balancing congestion after MISO adjusted the TCDC to $5,000 per MWh rather than decommitting a resource committed in the day-ahead market.

- Net JOA congestion payments from PJM and SPP were about $63.7 million in 2025, compared to $5.2 million in net JOA congestion payments to PJM and SPP in 2023.
- MISO uplifted 15 percent less in JOA costs to SPP and PJM, which fell to $56.4 million in 2025.

We are investigating the recent increase in balancing congestion because it indicates potential modeling issues. Based on our findings, we will be working with MISO to address any issues.

FTR Market Performance

FTRs represent forward entitlements to day-ahead congestion and help allocate the value of the transmission system. Because transmission customers pay the embedded costs of the system, they should be entitled to its economic property rights. MISO accomplishes this by allocating Auction Revenue Rights (ARRs) to transmission customers based on their network load and resources. ARRs give customers the right to receive FTR auction revenues from the sale of the ARRs or to convert their ARRs into FTRs and receive day-ahead congestion revenues.

FTR markets perform well when FTR prices accurately reflect the expected value of day-ahead congestion, which results in low FTR profits for buyers (day-ahead congestion payments minus the FTR price). Even if FTR prices reasonably reflect expected congestion, several factors may still cause actual congestion to be much higher or lower than FTR auction values. MISO currently runs two types of FTR auctions:

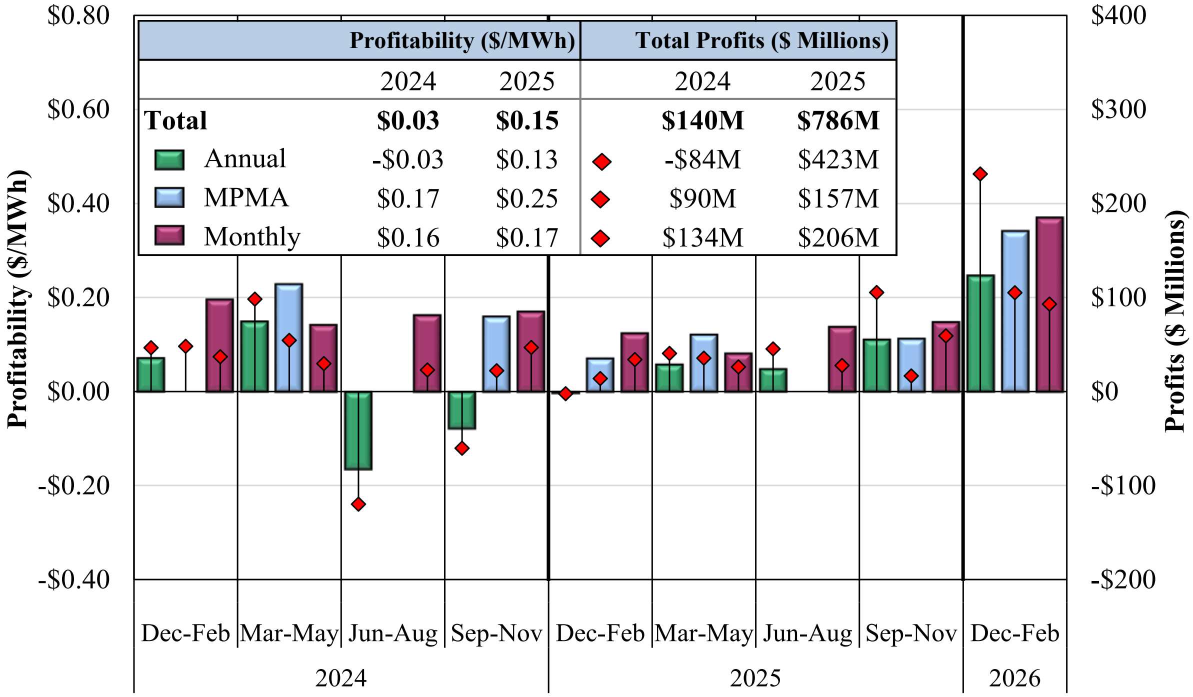
- An annual auction from June to May that includes seasonal and peak/off-peak resolution of bids, offers, and awards; and
- A Multi-Period Monthly Auction (MPMA) that yields monthly and seasonal peak/off-peak awards and facilitates FTR trading in future periods of the current year.

FTR Market Profitability

Figure 30 shows our evaluation of FTR profitability in these auctions. The bars show the seasonal profits for FTRs sold in each market, and the red diamonds show the profit margin for each class of FTRs. For comparison, this figure aggregates the profitability of monthly FTRs purchased in the MPMA by season. The figure shows results through February 2026 as part of the winter quarter that includes December 2025.

Annual FTR Profitability. Figure 30 shows that FTRs issued through the annual FTR auction were profitable overall, at $0.13 per MWh, up from -$0.03 per MWh in 2024. Generally, losses are most common in the annual auction because it occurs furthest from the settlement horizon. In addition, planned transmission outages that affect congestion are often under-reported and more uncertain, so some conversions of ARRs to FTRs occur at prices that do not reflect expected congestion.

Figure 30: FTR Profits and Profitability
2024–2025

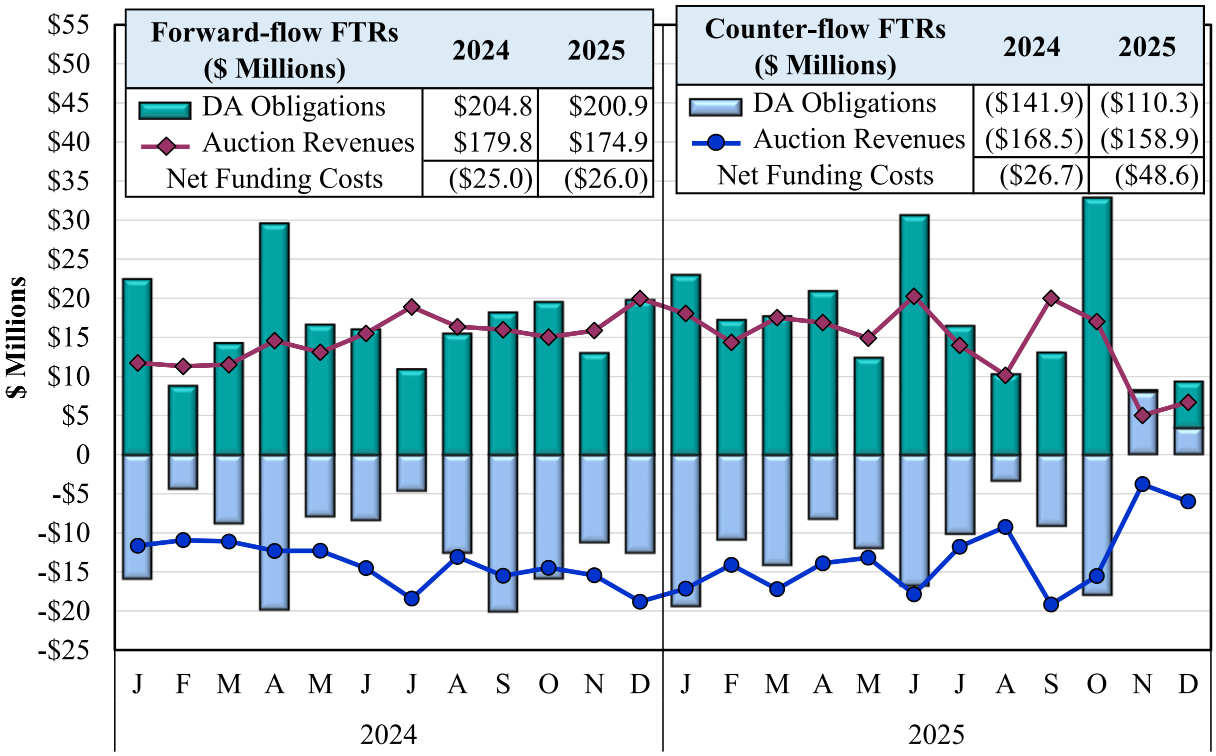


FTR Profitability in the MPMA and Monthly Auction. Figure 30 shows that FTRs purchased in the MPMA and prompt month auction continued to be profitable. Profitability rose 47 percent in the MPMA auctions and 6 percent in the monthly auctions. In general, the MPMA and monthly markets should produce prices that align more closely with anticipated congestion because they clear closer to the operating timeframe, when better information is available to forecast congestion.

Figure 31 evaluates MISO's sale of forward-flow and counter-flow FTRs by comparing auction revenues from the MPMA prompt month (the first full month after the auction) with the day-ahead FTR obligations for the FTRs sold. The figure shows forward-flow and counter-flow FTRs separately. The net funding costs in the inset tables are the difference between the auction revenues and the day-ahead obligations. A negative value indicates that MISO sold forward-flow FTRs at a price below their ultimate value or bought counter-flow FTRs at a price above their ultimate value.

The analysis shows that the discount on forward-flow FTR sales rose 4 percent in 2025, increasing net funding costs (i.e., profits from these FTRs) from $25 million to $26 million. These results indicate that market expectations of congestion were relatively accurate on average in most prompt months. However, unforeseeable events such as emergency days and tight conditions in late June led to unexpected increases in day-ahead congestion and significant profits for forward-flow FTRs in those months.

Figure 31: Prompt-Month MPMA FTR Profitability
2024–2025



In addition to selling forward-flow FTRs in the MPMA FTR auction, MISO often buys back capability on oversold transmission paths by selling counter-flow FTRs (i.e., negatively priced FTRs). In essence, MISO pays a participant to accept an FTR obligation in the opposite direction to cancel out excess FTRs on a constraint. Net funding deficits for counter-flow FTRs were significant in 2025 and 82 percent higher than in 2024, indicating that MISO substantially overpaid for these FTRs relative to the day-ahead congestion value on average. However, auction revenues in some months, such as January, June, and October, aligned well with the value of the counter-flow obligation.

These results indicate that the MPMA lacks the liquidity to eliminate the differences between FTR prices and congestion values. Identifying and eliminating barriers to participation should improve convergence between auction revenues and the associated day-ahead FTR obligations. If MISO cannot identify such improvements, it may be beneficial to examine its auction processes and determine whether to establish price-based limits on the sale of forward or counterflow FTRs.

Improving the Performance of FTR Markets

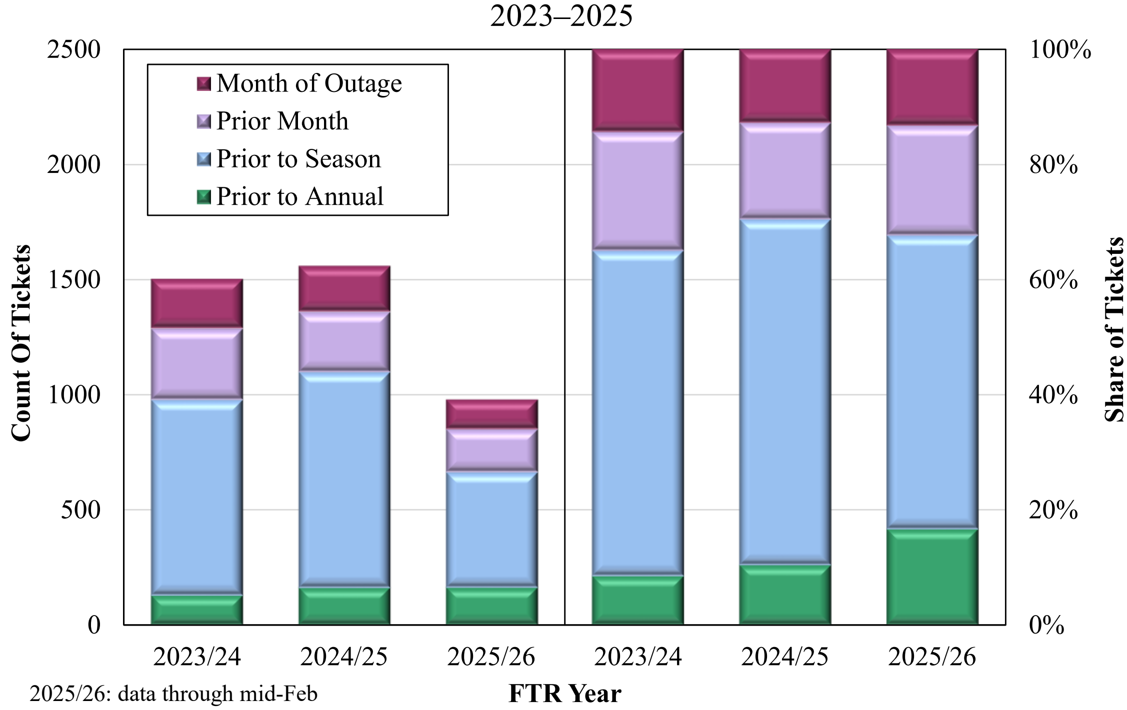
Efficient FTR markets set prices that reflect accurate expectations of day-ahead congestion. However, the results above show that these markets have not always performed well, particularly in the MPMA and monthly auctions. We have evaluated and identified two principal factors affect FTR market performance:

- The accuracy of the network topology, which depends largely on the completeness of the transmission outages that will occur; and
- The liquidity of the FTR auctions.

Outage Reporting. Transmission owners must schedule outages in MISO's CROW system 12 months in advance. However, some transmission owners have not complied with this requirement, and some outages are not known far in advance. As a result, the outages reflected in the annual FTR process are much less complete than those reflected in the timelier auctions. Figure 32 shows the count and shares of planned transmission line outages of 230kV or higher with a duration of 5 days or more that are scheduled prior to (i) the annual auction, (ii) the seasonal MPMA, (iii) the monthly auction, and (iv) after the monthly auction.

Figure 32 shows that less than 20 percent of planned outages are scheduled before the annual auction. Far less than 10 percent of planned outages that start in the winter and spring are scheduled before the annual auction because those seasons are further in the future than the summer and fall seasons.

Figure 32: CROW Outage Tickets by Creation Date
2023–2025



An additional problem with the outages included in the annual auction is that MISO must be conservative, so it assumes that an outage scheduled for longer than 5 days will occur over the entire season. In contrast, just over half of outage tickets were first created before the season, and an additional 19 percent were created in time for the prior month's auction. Hence, network modeling is much more accurate in the monthly and seasonal timeframes because most planned outages are known by then.

Participation and Liquidity. Although network topology is much more accurate in the MPMA and monthly auction timeframes, these markets tend to perform worse at setting prices that reflect realized congestion in the day-ahead market over time. This indicates that these auctions are not sufficiently liquid.

Annual FTR auction prices align more closely with realized congestion than monthly auction prices because transmission customers participate in the annual auction. MISO currently allocates ARRs only once, before the Annual FTR Auction. LSEs must decide whether to accept the annual auction revenues or convert their allocations to FTRs. An LSE that specifies the price at which it will accept the FTR auction revenues effectively submits a reservation price to sell the FTR. An LSE that chooses to self-schedule the conversion of ARRs to corresponding FTRs effectively submits a reservation price of infinity. In both cases, transmission customers act as active sellers of FTRs in the annual auction.

In contrast, no ARRs are allocated after the annual auction, so transmission customers cannot participate as FTR sellers as they do in the annual auction. Instead, MISO serves as the seller on the customers' behalf and offers any residual FTR capability at a reservation price of zero. If bidder liquidity is not sufficient on an FTR path, the FTRs on that path can be priced far below their value.

To facilitate transmission customer participation in the seasonal and monthly FTR auctions, increase liquidity, and allocate and sell FTRs based on a more accurate representation of the transmission network, we recommend that MISO:

- Make a smaller share of transmission capacity (e.g., one third) available for ARR allocation and sale in the Annual FTR Auction, down from 90 percent currently;
- Release additional transmission capacity to be allocated as ARRs and sold as FTRs in seasonal and monthly FTR auctions (e.g., half of the remaining capacity in each); and
- Modify the ARR allocation process to better align with customers' current use of the system and to facilitate allocation of capability that would otherwise remain unallocated under the current generation-to-load nomination process.

By withholding more capacity for the seasonal or monthly auctions, these markets will perform better, and customers will likely receive a higher share of the system's full value. This will also greatly reduce the likelihood of overselling constraints in the annual auction, which would compel MISO to purchase counter-flow FTRs.

Aggregate Node Definitions Affecting FTR Funding

The recent influx of large new data center loads for cloud computing and crypto-currency mining has sharply increased the risk that load distribution will change significantly during the 16-month span from completion of the ARR studies to the end of the FTR year. MISO redefines the aggregate definitions used in the ARR and FTR processes daily based on the distribution of state-estimated loads from seven days earlier. This daily update process keeps the day-ahead and real-time definitions synchronized and may improve some LSEs' congestion hedges. However, the revised definitions may vary significantly from the assumptions in the FTR market.

We evaluate how updates to the composition of aggregate nodes, such as load zones and ARR Zones, affect market funding. This analysis shows a $74 million change in valuation between June 2024 and December 2025 caused by redefining node aggregates in the day-ahead market after FTR positions were established.

We recommend that MISO consider options to mitigate this risk, such as:

- Incorporating forecasted changes to load aggregates in FTR definitions;
- Using a single FTR aggregate composition for both peak and off-peak periods to better align with the single daily day-ahead/real-time definition;
- Applying the FTR market composition to day-ahead/real-time pricing when FTR positions greatly exceed actual withdrawals; and
- Discontinuing trading at ARR/load zones where no ARRs are awarded or load is settled.

C. Congestion over the Transfer Constraint

The Regional Directional Transfer Limit (RDT) is a contractual constraint between MISO's Midwest and South subregions that limits scheduled physical flows to 3,000 MW from the Midwest to the South and 2,500 MW from the South to the Midwest.[19] Unmodeled physical flows over the RDT can cause total flows to exceed the contract limits.[20] To prevent this, MISO has taken two actions: (a) implementing a post-contingent constraint, the Reserve Procurement Enhancement (RPE), to hold headroom on the RDT; and (b) actively managing the RDT limit to avoid unmodeled exceedances. MISO derates the RDT limit to 90 to 92 percent of the contract limit by default and often by more. These derates can produce widespread price effects throughout each subregion. In 2025, MISO bound the RDT in real time at an average of 370 MW

19 The RDT agreement with SPP and the Joint Parties applies to flows scheduled in the MISO real-time UDS model between the North and South regions. Differences between scheduled flows in the UDS and actual flows are "unmodeled" flows.

20 Unmodeled physical flows are caused by regulation deployments and generators or load deviations.

below its contractual limit. Limiting interregional transfers that do not contribute to congestion on the SPP or the Joint Parties' systems is inefficient.[21]

Currently, MISO uses a two-step TCDC for the RDT, with a lower step of $40 per MWh at the limit and a second step of $500 per MWh starting at 102 percent of the modeled limit. Hence, when the RDT violates the limit by more than 2 percent, prices throughout each subregion move to establish a $500 spread between the Midwest and South subregions. MISO also models the RPE constraint that limits flows between subregions after a supply-side contingency and assigns it a single demand value of $200 per MWh. Our evaluation of these transfer constraints reveals the following:

- Dispatch can change the magnitude and direction of flows over the transfer constraint, giving MISO a valuable capability to accommodate large, rapid changes in intermittent renewable output in the Midwest.
- RDT deratings cause MISO to use only 84 percent of the RDT when it binds.
- When transfer constraints are violated, they often produce subregion-wide price spreads of $700 per MWh because the RDT and RPE demand curve values ($500 and $200) are added, which was not intended. These violations should be priced at $500 per MWh.

To address these concerns, we recommend that MISO modify the RDT Transmission Constraint Demand Curve (TCDC) by adding lower-valued steps starting at 80 percent of the contract limit and by raising the energy plus STR limit to align with the highest penalty step on the TCDC. These demand curve adjustments will increase RDT utilization when subregional transfers are highly valued and reduce the burden on MISO operators, who must constantly monitor and adjust the RDT limit in the real-time market. We analyzed the production cost savings from modifying the RDT demand curve and from increasing utilization of the contract path by eliminating derates that were no longer required to avoid contract violations.

We analyzed June through December 2025 and found a $700 million reduction in Midwest market costs over those seven months. Most of the reductions occurred from June through August because the RDT bound more frequently during the summer months. The simulation also produced a $2.41 per MWh average reduction in Midwest energy prices over the study period. The largest source of cost savings is the additional transfer capability above 2,300 MW that the proposed TCDC unlocks by eliminating the need for operators to derate to that level by default. Greater RPE constraint utilization yields additional savings by reducing demand for Short Term Reserves. This allows generators in the unconstrained region to hold less headroom for STR and produce more energy. Overall, the proposed TCDC ensures contract compliance while allowing

21 The RDT is a proxy for physical limits on SPP and the Joint Parties systems. To the extent the RDT is binding when no congestion is being caused by MISO's regional transfers, or when the congestion can be more efficiently managed by other means (e.g. M2M coordination) then the RDT is inefficient.

the cheapest available generation to meet STR and energy demands, lowering the System Marginal Price (SMP) by about $4 per MWh in binding intervals.

To further reduce inefficiencies, we recommend that MISO improve coordination and settlements for constraints in adjacent areas affected by the transfers. This would increase MISO's ability to transfer power while reducing congestion effects on neighboring systems.

Regional Directional Transfer Flows and Regional Reliability

Actual flows on the RDT averaged 793 MW in the South-to-North direction in 2025, while North-to-South flows generally correlated with wind output. Until recently, all wind resources in MISO were in the Midwest region, and the vast majority still are. Therefore, when MISO experiences high wind output, RDT flows tend to run North to South. Conversely, when wind output falls sharply, flows tend to reverse and run South to North. The MISO market's ability to shift flow quantity and direction by more than 5,000 MW provides tremendous value to customers in both regions.

D. Market-to-Market Coordination with PJM and SPP

MISO's market-to-market (M2M) processes under Joint Operating Agreements (JOAs) with neighboring RTOs enable the RTOs to manage constraints that affect both RTOs efficiently. The process allows each RTO to use redispatch from the other RTOs' units to manage congestion when doing so costs less than its own redispatch.

Under the M2M process, each RTO is allocated Firm Flow Entitlements (or FFEs) on the coordinated constraint. The RTOs calculate the constraint's shadow price based on each RTO's cost of relieving it, and the RTO with the lower relief cost reduces flow to help manage the constraint. When the non-monitoring RTO (NMRTO) provides relief and reduces its market flow below its FFE, the monitoring RTO (MRTO) compensates it by paying the marginal value of the relief. Conversely, if the NMRTO's market flow exceeds its FFE, it pays the MRTO for the excess flow times the MRTO's marginal relief cost.

Summary of Market-to-Market Settlements

Overall congestion on M2M constraints increased in 2025, with the real-time congestion value on MISO M2M constraints rising 11 percent to $808.4 million. Congestion on external M2M constraints (those monitored by PJM and SPP) was largely unchanged. The congestion value for all external M2M constraints totaled $100.4 million. This includes only MISO flows on these constraints, so the total value for SPP and PJM is much higher.

The congestion value for the M2M constraints differs from the settlement costs MISO customers incur. Each RTO's flows on the M2M constraints relative to its FFEs determine the settlements. Table 8 shows MISO's annual M2M settlements with SPP and PJM over the past two years.

Table 8: M2M Settlements with PJM and SPP ($ Millions)
2024–2025

	PJM	SPP	Total
2025	$89	-$84	$5
2024	$41	-$110	-$69

Table 8 shows that net payments generally flowed from PJM to MISO because PJM exceeded its FFEs on MISO's system. Almost 60 percent of PJM's payments to MISO occurred in just 4 months: January, April, October, and December. Just a few constraints drove these results, including three M2M constraints with PJM that totaled $44 million in congestion value. Wind in PJM affects these constraints, while MISO has limited internal relief. During these months, wind generation tends to be high. This makes M2M constraints that wind resources significantly affect more difficult to manage because their fast ramp rates create volatility and oscillations in relief request quantities from the NMRTO.

MISO generally makes M2M payments to SPP, partly because SPP has relatively high FFEs on key constraints in both SPP and MISO. For other constraints, differences in SPP's FFE levels partly reflect differences in how completely SPP and MISO include historic transmission reservations in their FFE calculations. A substantial portion of MISO's historic transmission reservations is not included in the FFE calculations. We also question whether FFEs should be based on *reservations* rather than *schedules*. Schedules are generally a fraction of reservation quantities and more accurately represent historic use of the system. As wind output along the SPP seam grows and generator retirements reduce MISO's ability to relieve wind-related constraints, we expect payments to SPP to continue to grow. Ultimately, the RTOs must reform and update their FFE calculation processes because the current process, which dates to 2004, is increasingly unreasonable.

Market-to-Market Effectiveness

One metric we use to evaluate the M2M process is the convergence of M2M constraint shadow prices in each market. When the process works well, the NMRTO continues to provide additional relief until the marginal cost of its relief (its shadow price) equals the marginal cost of the MRTO's relief. Our analysis shows that, for the most frequently binding M2M constraints, the M2M process generally contributes to shadow price convergence and lowers the MRTO's shadow price after the M2M process begins.

However, we found that on some constraints, shadow prices fail to converge because the MRTO does not request enough relief. This occurs because the current relief request software does not consider shadow price differences between the RTOs. When the NMRTO's shadow price remains much lower, the requested relief should increase to lower congestion costs and accelerate convergence. At other times, the software can request too much relief, causing constraints to bind and unbind in subsequent intervals, a pattern called "oscillation". To address these issues, we have recommended that MISO base relief requests on the RTOs' respective shadow prices and implement an automated means to control constraint oscillation. In the long term, MISO should use dynamic transmission constraint demand curves to reflect the actual relief the NMRTO provides in the dispatch of the MRTO.

Evaluation of the Administration of Market-to-Market Coordination

Effective administration of the M2M process is essential because failing to identify or activate an M2M constraint raises two concerns:

- *Efficiency concerns*. Coordination with the NMRTO to relieve the constraint does not achieve the savings, and congestion costs are higher than necessary.
- *Equity concerns*. The NMRTO may exceed its firm flow entitlements on the constraint substantially, with no compensation to the MRTO.

Although the M2M process improves efficiency overall, we evaluated three issues that can reduce coordination efficiency and effectiveness:

- Failure to test all constraints that might qualify as new M2M constraints;
- Delays in testing constraints after they begin binding to determine whether they should be classified as M2M; and
- Delays in activating current M2M constraints once they bind.

We developed a series of screens to identify constraints that should have been coordinated but were not because of these three issues. Table 9 shows total congestion on these constraints. For the first two reasons (never classified and testing delay), we account for the time needed to test a constraint by excluding the first day it was binding.

MISO has a tool to identify potential M2M constraints for testing. Nonetheless, congestion on PJM constraints that were never tested was significant, so we encourage MISO to evaluate ways to improve its M2M processes and the timeliness of its testing process.

Table 9: Real-Time Congestion on Constraints Affected by Market-to-Market Issues
2023–2025

Item Description	PJM ($ Millions)			SPP ($ Millions)			Total ($ Millions)		
	2023	2024	2025	2023	2024	2025	2023	2024	2025
Never classified as M2M	$5	$38	$25	$33	$4	$4	$38	$42	$29
M2M Testing Delay	$5	$2	$9	$40	$22	$34	$45	$24	$43
M2M Activation Delay	$0	$2	$1	$1	$1	$24	$2	$3	$25
Total	$10	$42	$35	$74	$27	$62	$84	$69	$97

Market-to-Market Test Criteria Software

Identifying the constraints to coordinate under the M2M processes is important for efficient, reliable coordination, equitable settlements, and improved price signals in the NMRTO market. Currently, the NMRTO identifies a constraint as an M2M constraint when it has:

- A generator with a shift factor greater than five percent; or
- Market flows over the MRTO's constraint greater than 25 percent of total flows (for the SPP JOA) or 35 percent of total flows (for the PJM JOA).

These two tests do not optimally identify constraints that would benefit from coordination because they do not consider the economic relief the NMRTO will likely have available.[22] The single-generator test is particularly questionable because it ignores the unit's size and economics, so it does not ensure that the NMRTO has any economic relief. Our analysis in Section V.E of the Analytic Appendix shows several M2M constraints for which the NMRTO has a small share of the economic relief and limited ability to help manage congestion. Most of these constraints should not be M2M constraints because the coordination savings are likely lower than the administrative costs.

Based on this analysis, we find that the current tests, particularly the five percent GSF test, often identify constraints for which the benefits of coordination are very small, especially high-voltage constraints where GSFs tend to be higher. Hence, we recommend replacing the five percent test with two discrete tests based on the available relief controlled by the NMRTO:

- The share of available relief capability from the NMRTO (e.g., 10 percent); and/or
- The NMRTO relief as a percentage of the transmission limit (e.g., 10 percent).

Our analysis shows that implementing this recommendation would likely reduce the total number of M2M constraints. This matters because the number of coordinated market-to-market constraints has risen rapidly in recent years.

Congestion Convergence and Constraint Transfers

A core component of M2M coordination is the software that determines the relief requested from the NMRTO. The goal of the coordination is to converge the value of congestion, as reflected in the constraint shadow price, in the MRTO on NMRTO dispatches. If the software requests insufficient relief, the MRTO's shadow price will remain much higher than the NMRTO's, and the markets will forgo significant savings.

The M2M relief software contains parameters (adders) that increase the relief request quantity by a given percentage. MISO applies these adders when the baseline relief request is too low. MISO

22 Economic relief is any relief that could be provided in five minutes at a shadow price less than $200.

sets the adders to five percent by default, but operators can override this value for each flowgate. SPP has often advocated setting the adders to zero on its constraints. Table 10 shows the shadow price convergence on all M2M flowgates with SPP in 2025.

Table 10: Shadow Price Convergence on M2M Flowgates with SPP in 2025

Type	# Flowgates	Avg. % Convergence with MISO Shadow Price	Cost of Non-Convergence ($ Millions)
Standard	90	92%	$36
Reverse-Role	46	151%	$85

The analysis shows that M2M reverse-role flowgates often converge poorly. For these flowgates, MISO's shadow price is often more than 50 percent higher than SPP's shadow price. Poor convergence adversely affected several of the most-congested MISO-controlled flowgates in 2025 and significantly increased MISO's M2M costs.

MISO and SPP can agree to transfer flowgate monitoring responsibility from the MRTO to the NMRTO; these are reverse-role flowgates. Ideally, this should occur only when the NMRTO controls a significant majority of the economic flow relief on the flowgate. We found that most constraints MISO coordinated with adders equal to zero were SPP flowgates transferred to MISO as reverse-role flowgates because SPP requested zero adders.

We also found that some of these reverse-role flowgates likely should not have been transferred because MISO did not have more economic relief on the flowgates than SPP. To address the costs and inefficiencies these issues caused, we recommend MISO:

- Adopt criteria to monitor SPP constraints as reverse-role flowgates; and
- Condition acceptance of monitoring responsibility for SPP constraints on the use of reasonable adders.

Our evaluation also finds that M2M constraint convergence is much worse in the day-ahead market. MISO and PJM implemented a process to coordinate and exchange FFEs in the day-ahead market, but they do not actively use it. We recommend that MISO continue working with SPP and PJM to implement FFE exchanges on M2M constraints.

E. Congestion on Other External Constraints

In addition to congestion from internal and external M2M constraints, congestion in MISO can occur when it models the impact of its own dispatch on external constraints. MISO must activate these constraints and reduce its market flows when other system operators invoke Transmission Loading Relief (TLR) procedures. As a result, MISO's LMPs reflect the marginal cost of providing the requested relief, and MISO's customers pay the associated congestion costs.

Relief requests for these constraints are often inefficient and inequitable because:

- MISO receives relief obligations based on forward direction flows across the impacted flowgates, even if on net (when reverse-direction flows are included) its market flows relieve the constraint; and
- Virtually all MISO flows over external constraints are deemed non-firm, and thus subject to curtailment before firm transactions, even though most are associated with dispatching network resources to serve MISO load.

As a result, MISO's relief obligations are often large and generate substantial congestion costs. Further, we have generally found that external TLR constraints often are not physically binding when they bind severely in MISO in response to a relief request. To address this issue, we have recommended MISO pursue a JOA with the adjacent systems that call TLRs most frequently—TVA and IESO—to coordinate congestion relief. Because TVA acts as the reliability coordinator for the Associated Electric Cooperative, Inc. (AECI), such a JOA would produce large benefits by allowing AECI resources to provide significant economic relief on MISO's transmission constraints and vice versa.

F. Transmission Ratings and Constraint Limits

For the past several years, we have estimated significant potential benefits from improved use of the transmission system, especially from broader application of Ambient Adjusted Ratings (AARs) and emergency ratings. For most transmission constraints, the amount of power that can flow through a facility depends on the heat that the power flow produces. When temperatures are cooler than the typical assumptions used to rate facilities, the system can accommodate additional power flows.[23] Therefore, if TOs develop and submit ratings adjusted for temperature or other relevant ambient conditions, MISO can operate to higher transmission limits and achieve substantial production cost savings. Most TOs do not provide ambient-adjusted ratings because they have little economic incentive to do so.

In December 2021, FERC issued Order 881, which requires TOs to provide AARs and emergency ratings based on facility-specific evaluations by mid-2025. On March 17, 2025, MISO filed a motion to extend the compliance deadline to the end of 2028 because of software delays. We protested this extension for applying AARs in the real-time market because this element of the Order 881 mandate could be fully satisfied over the next year and because the vast majority of AAR benefits will accrue in the real-time market.

23 Temperature is one factor, while ambient wind speed, humidity, and solar radiance can also be important determinants of dynamic ratings. Our analysis evaluates only ambient temperature impacts.

Estimated Benefits of Using AARs and Emergency Ratings

As in past years, we estimated the value of operating at higher transmission limits from the consistent use of temperature-adjusted and emergency ratings for MISO's transmission facilities.[24] Section V.H of the Analytic Appendix describes this analysis in detail, and Table 11 summarizes it. As the table shows, two thirds of the benefits can be achieved on relatively few facilities and MISO currently enables implementation of real-time AARs via existing interfaces.

Table 11: Benefits of Ambient-Adjusted and Emergency Ratings
2024–2025

		Savings ($ Millions)			# of Facilites for 2/3 of Savings	Share of Congestion
		Ambient Adj. Ratings	Emergency Ratings	Total		
2024	**Midwest**	$122.5	$89.98	$212.5	24	12.9%
	South	$10.1	$8.98	$19.1	1	8.9%
	Total	**$132.6**	**$99.0**	**$231.6**	**25**	**12.4%**
2025	**Midwest**	$207.3	$88.71	$296.0	19	15.8%
	South	$10.7	$15.63	$26.3	4	7.5%
	Total	**$218.0**	**$104.3**	**$322.3**	**23**	**14.5%**

Over the past two years, average benefits approached 15 percent of the real-time congestion value. Total potential savings in 2024 and 2025 exceeded half a billion dollars. Benefits from temperature adjustments accrue primarily in the non-summer months, when static ratings are most understated. Benefits from emergency ratings are more evenly distributed throughout the year. The Analytic Appendix details how transmission-owner service areas in 2025 accounted for these estimated benefits.

G. Operator Congestion Management Actions

MISO operators play a critical role in maintaining reliability, which can require actions to avoid transmission violations. We evaluate these actions in this subsection because they can substantially affect market outcomes. Ultimately, the goal should be to manage network flows through the market dispatch software to the maximum extent possible. However, this can be challenging and can prompt operator actions when:

- Resources do not respond to MISO's dispatch instructions, which has been an issue for several intermittent renewable resources; and
- Forecast errors in the output of intermittent resources, discussed in Section III.B.

24 We used temperature and engineering data to estimate the temperature adjustments and assume emergency ratings are 10 percent higher than the normal ratings, which is based on other facilities for which TOs submit emergency ratings. We estimate the value of both increases based on the shadow prices of the constraints.

Operator interventions can be classified by how effectively and efficiently they address the situations operators face. In principle, interventions that enable the market to address the issue are more efficient than interventions that circumvent the models. In addition, some operator actions are ineffective for certain issues. Table 12 describes the main types of interventions available to operators and the associated pros and cons for addressing transmission-related reliability concerns.

Table 12: Types of MISO Operator Intervention

Operator Decisions	Effect of Action	Pros / Cons
TCDC Adjustment	Allows the dispatch model to access more costly dispatch actions to lower constraint flows.	Allows the dispatch model to optimally manage the constraint.
Commit Resources that can Provide Relief	Reduces flows on constraints by providing counterflows.	When units are economic to commit, they will lower costs and allow the dispatch to better manage the flows.
Transmission Derate with Limit Control Adjustment	Causes the dispatch to reduce the modeled flows to makes room on the constraint for the unmodeled constraint flows.	An efficient means to account for *unmodeled* flows. Not efficient or effective when the violation is caused by modeled flows.
Manual Redispatch (MRD)	Manually specifies a dispatch level for a resource to reduce constraint flows.	Provides quick relief, but is rarely efficient. Prevents the dispatch from efficiently pricing the congestion and increases uplift.
Cap Resources	Manually specifies a maximum dispatch level for a resource to prevent increasing constraint flows.	Effectively limits flows, but is rarely efficient. Prevents the dispatch from efficiently pricing the congestion and increases uplift.

The top three actions listed in the table are much more efficient than the bottom two because they use the markets to address the issues or are compatible with the markets.

- Increasing the TCDC raises the costs the dispatch model will incur to manage the constraint. This is effective when the constraint is already in violation and the current TCDC cannot provide additional relief.
- Committing resources to relieve congestion is efficient and compatible with the market when the LAC model recommends the commitments as economic.
- Derating a transmission constraint in the dispatch model causes MISO's dispatch model to redispatch resources around the constraint. This is effective when un-modeled physical flows are not accurately perceived by the dispatch model.

The final two actions circumvent the market and are generally less efficient: manual re-dispatch and dispatch caps that override or constrain the market's dispatch. These actions raise costs and prevent prices from reflecting the costs. Figure 33 shows the frequency of these actions.

Figure 33: MISO Operator Actions for Congestion Management
2023–2025

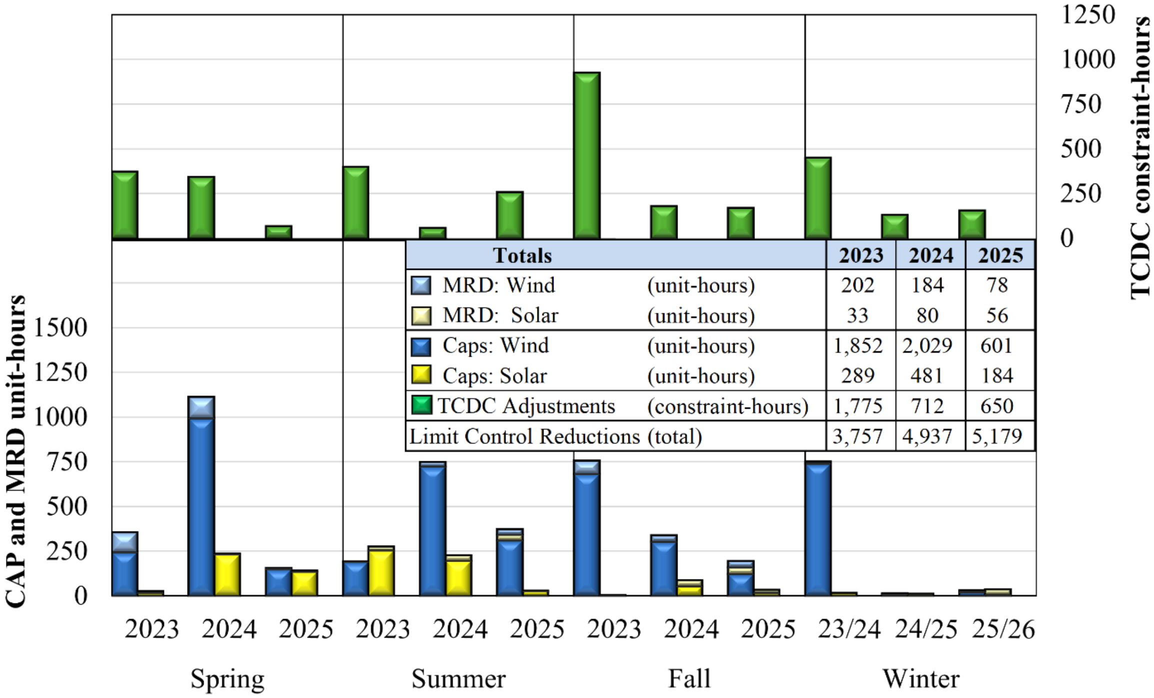


Figure 33 shows that manual dispatch actions and dispatch caps previously grew with intermittent renewable penetration but declined in 2025. We have worked with MISO to develop operational guidelines based on the most efficient and effective measures to manage congestion reliably, and MISO's reliance on these guidelines is reflected in the 2025 outcomes. MISO should continue minimizing reliance on dispatch capping and MRDs as more intermittent resources enter the generating fleet.

Additionally, MISO is working on other changes discussed in Section IV of this report to improve real-time market forecasts and provide efficient incentives for intermittent resources to follow dispatch instructions. These improvements are critical because forecasting and dispatch issues related to intermittent resources have caused most of the transmission congestion challenges that compelled operators to take the actions described above.

Figure 33 also shows that the frequency of manual transmission deratings through "limit control" reductions increased by 5 percent from 2024, continuing a trend observed last year. These deratings should be minimized because they can be costly. We estimated that they cost $125 million in 2023, $144 million in 2024, and $137 million in 2025. The most common and appropriate use of limit control is to derate transmission limits to account for deviations between modeled and actual flows (unmodeled flow or deviations). However, in some cases, limit control adjustments are sub-optimal and lead to inefficient market outcomes. We addressed derating constraints in our operational guidelines, which should improve the efficiency and effectiveness of manual transmission deratings.

H. Other Key Congestion Management Issues

MISO generally experiences significant real-time congestion each year, reaching a record $3.7 billion in 2022 and $2.2 billion in 2025. Therefore, improving congestion management efficiency can deliver sizable savings. We discussed many of these improvements above and discuss three additional improvements in this subsection.

Decommitting Resources that Cause Congestion

MISO does not decommit day-ahead committed units for economic reasons. Although economic decommitments could create DAMAP exposure, decommitting a resource can sometimes alleviate severe congestion and reduce production costs. In our 2023 report, we assessed the potential benefits of a day-ahead economic decommitment process through case studies using MISO's Look-Ahead Commitment (LAC) model. In these studies, LAC could suggest decommitments when they lowered costs. We found:

- Net savings were as high as $1 million in one instance of decommitting a unit, and Excessive Congestion Fund (ECF) savings accounted for the largest share.
- Most cases also resulted in significant production cost savings.
- Congestion in these case studies fell by as much as $1.7 million. In two case studies, the decommitments eliminated all of the congestion they caused.
- In every case, the increase in DAMAP costs paid to the decommitted resources was substantially less than the savings.

In 2025, we ran the same analysis for additional case studies. One study found cost savings of $25 million from decommitting two units during a period of high congestion. This case study had particularly high ECF savings because the top step of the constraint's TCDC was $5,000 per MWh. Based on these results, we recommend that MISO develop tools and procedures to identify day-ahead committed resources that cause substantial congestion and allow LAC to recommend decommitting these resources when economic.

Coordinating Outages that Cause Congestion

Generators take planned outages to perform periodic maintenance, evaluate or diagnose operating issues, and upgrade or repair various systems. Similarly, transmission operators take planned outages to implement upgrades and perform planned maintenance on transmission facilities. These outages generally reduce system transmission capability during the outage period. When outage requests are submitted, MISO evaluates the reliability effects of the planned outages, including contingency and stability studies.

Participants tend to schedule planned outages in shoulder months, assuming the opportunity costs are lower because temperatures tend to be mild and demand relatively low. However, this is not always true. Multiple participants may schedule generation outages in a constrained area or transmission outages into an area without knowing what others are doing. Absent a reliability concern, MISO cannot deny or postpone a planned outage, even when doing so could provide sizable economic benefits. We analyzed the effects of uncoordinated planned outages on congestion by calculating the portion of 2025 real-time congestion value that occurred on internal constraints substantially affected by two or more planned outages (at least 10 percent of the constraints' flows).

Our analysis indicates that 28 percent of total real-time congestion on MISO's internal constraints in 2025 ($625 million) was attributable to multiple planned generation outages. In three months, more than one-third of monthly congestion was associated with outages. This may understate the effects of planned generation outages on MISO's congestion because it does not include transmission outages scheduled at the same time. We continue to recommend that MISO seek broader authority to coordinate planned generation and transmission outages.

Identification and Use of Economic Transmission Reconfigurations

In the *2021 State of the Market Report*, we highlighted the benefits of identifying and deploying network reconfigurations (e.g., opening a breaker) when they are reliable and economic. Reliability Coordinators do this regularly to address congestion-related reliability concerns, normally under procedures established in Operating Guides in consultation with the TOs. However, using reconfiguration options economically to manage congestion can provide substantial benefits.

Therefore, we continue to recommend that MISO work with TOs to develop tools, processes, and procedures to identify and analyze reconfiguration options and employ them to reduce congestion, rather than only for reliability. In 2022, MISO created the Reconfiguration for Congestion Cost Task Team to evaluate and implement reconfiguration requests. In 2025, it successfully implemented very few reconfiguration requests. However, MISO has no near-term plans to develop internal tools to suggest economic reconfiguration options, nor has it developed a process to ensure timely evaluations of alternatives. We recommend that MISO pursue these enhancements.

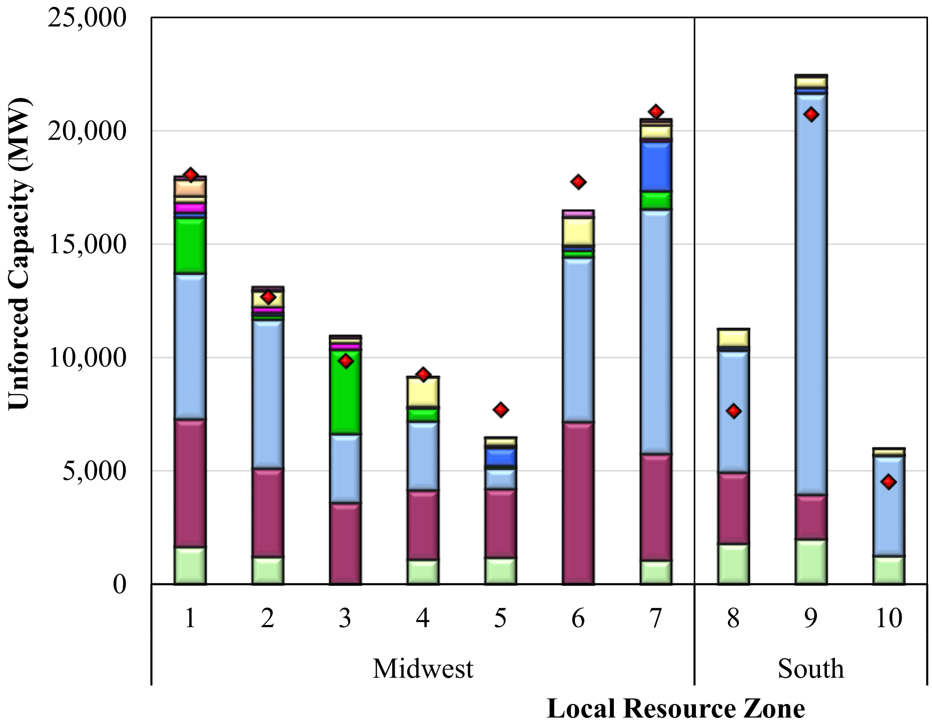
VI. Resource Adequacy

This section evaluates the performance of the markets in facilitating the investment and retirement decisions needed to maintain adequate resources. We assess supply adequacy for the upcoming summer and discuss recommendations to improve market performance.

A. Regional Generating Capacity

This subsection shows the distribution of existing generating capacity in MISO. Figure 34 shows MISO's Unforced Capacity (UCAP) by Local Resource Zone (LRZ) and fuel type, along with the coincident peak load in each zone.[25] UCAP values account for forced outages and intermittency. As a result, UCAP values for wind and solar units are much lower than Installed Capacity (ICAP) values, as shown in the inset table.

Figure 34: Distribution of Existing Generating Capacity
By Fuel Type and Zone, 2025



Share of Generating Capacity	UCAP	ICAP
Other	0.8%	0.6%
Battery	0.6%	0.4%
Solar	4.6%	9.9%
Oil	1.0%	0.9%
Hydro	2.9%	2.2%
Wind	6.1%	17.7%
Gas	48.8%	39.5%
Coal	26.9%	22.4%
Nuclear	8.3%	6.5%
Avg. Sum/Win Peak Load		

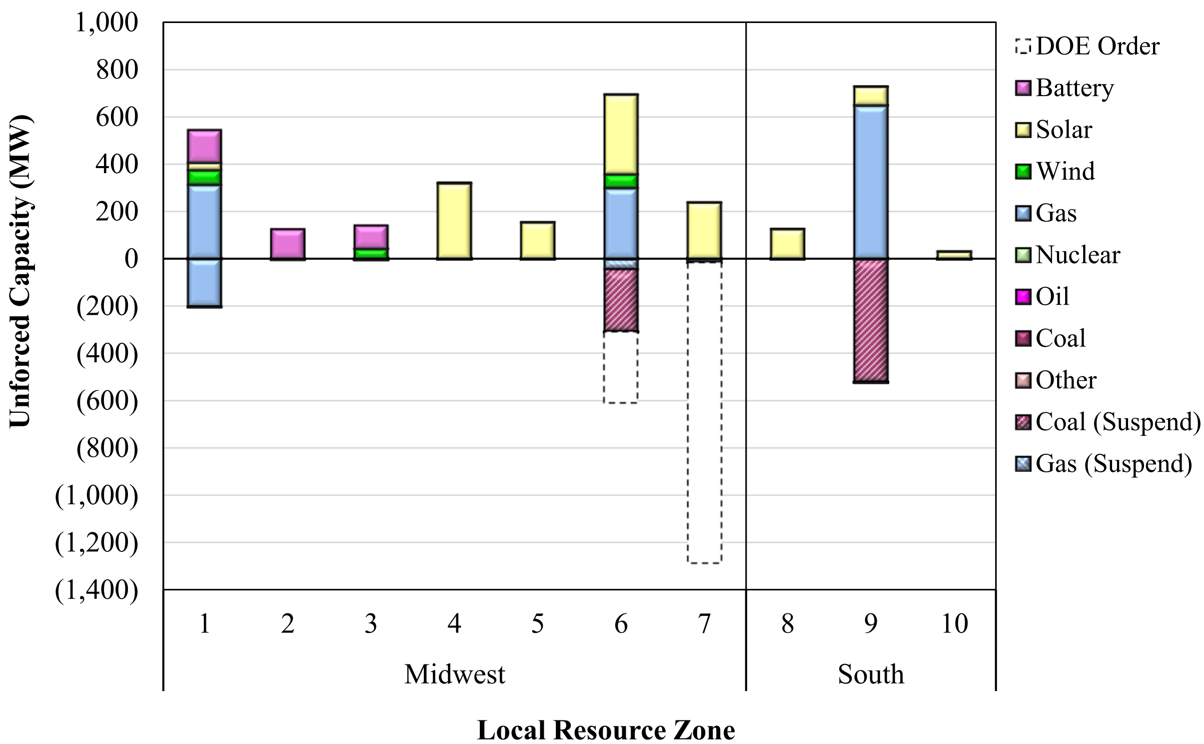
This figure shows that gas-fired resources account for a larger share of MISO's capacity than any other resource type, including coal-fired resources. It also shows that gas-fired capacity shares are generally larger in MISO South, which tends to cause large interregional flows from MISO South to the Midwest when natural gas prices are low and outages are minimal.

25 UCAP is based on data from the 2025–2026 PRA for the summer and winter seasons and excludes LMR capacity and capacity from resources that ceased operations before the end of the calendar year.

B. Changes in Capacity Levels

Capacity levels have fallen in recent years because accelerating retirements of baseload resources have been only partially offset by renewable additions, although additions outpaced retirements in 2025. Figure 35 shows capacity additions (positive values) and retirements in 2025. The hatched bar indicates newly suspended resources, which rarely return to service.[26] The ghost bars are coal resources scheduled to retire in 2025 that the U.S. Department of Energy (DOE) ordered to remain online. Figure 35 does not show retirements for resources suspended in 2024.

Figure 35: Distribution of Additions and Retirements of Generating Capacity
By Fuel Type and Zone, 2025



Capacity Losses

About 1.1 GW of resources retired or suspended operations in 2025, primarily coal and gas steam resources. These retirements are expected to continue in the near term because of state policies. Attachment Y to the MISO Tariff requires suppliers seeking to retire or suspend a unit to notify MISO at least 26 weeks in advance unless the unit is in outage. Based on a reliability study of the transmission system, MISO may designate a resource as a System Support Resource (SSR) and provide compensation. An SSR cannot retire or be suspended until MISO implements a reliability solution (e.g., transmission upgrades) or the reliability condition no longer exists.

26 Per Section 38 of the Tariff, the distinction between suspension and retirement is based on interconnection rights rather than the status or future plans for the facility. A suspended resource may be disassembled, maintaining its interconnection service to support a new facility at the same location. The status of the resource will eventually change from suspension to retirement if the interconnection rights are not used.

MISO has granted SSRs infrequently. In December 2025, MISO filed to terminate SSR status for three units in February 2026. No other resources have received SSR status.

The DOE issued emergency orders in June and December 2025 directing 1.6 GW of coal-fired capacity slated for retirement to remain online. Under the emergency orders, the DOE prohibited the resources from being capacity resources, which raises the costs of these orders and eliminates a key source of revenues to help cover the maintenance costs needed to comply with the orders.

New Additions

In 2025, about 3.1 GW of unforced new capacity entered MISO. Approximately 1.3 GW was from solar resources—roughly 1 GW in the Midwest and the remainder in the South—bringing MISO's solar capacity to approximately 18 GW by the end of 2025. The other additions include a new 650 MW combined-cycle unit in the South, 400 MW of gas replacement projects in the Midwest, and 370 MW of new Energy Storage Resources (ESRs). We expect ESRs to increase significantly in the coming years, and many are expected to be co-located with existing solar. In 2024, FERC approved MISO's Direct Loss of Load (DLOL) accreditation methodology, which incentivizes hybrid battery-solar installations over standalone solar because solar accreditation will fall sharply in the coming years.

C. Planning Reserve Margins and Summer 2026 Readiness

This subsection summarizes capacity levels in MISO and their adequacy to satisfy the forecasted summer peak loads in 2026. Because assumptions about supply availability and load can substantially change the planning reserve margins, Table 13 presents a base case and four additional scenarios that show a realistic range of summer peak reserve margins.

Base Scenario. We worked with MISO to align our base case scenario with the scenarios MISO used in its 2026 *Summer Readiness Workshop,* including the assumed 1,900 MW transfer limit between MISO South and Midwest.[27] This scenario also assumes that: a) MISO can access all DR resources in any emergency, and b) summer planned outages are those approved by April 1, 2026. To report all values on an ICAP basis, we: (a) replaced the UCAP-based Planning Reserve Margin (PRM) for demand response resources with an ICAP-based PRM, and (b) converted the UCAP-based ELCC value for wind resources to an ICAP-based value by scaling it based on the ratio of the ICAP and UCAP PRM values. For solar resources, we use the accredited value, which is based on historical performance from 2 pm to 5 pm, or 50 percent for new resources.

Realistic Scenario. The base-scenario assumptions are not consistent with expectations on peak summer days, so we also include a realistic scenario that assumes:

- The transfer capability between MISO South and Midwest will be 2,300 MW, consistent with MISO operations;

[27] We disagree with this assumption, but we use it to align our Base Case with MISO's Base Case.

- Planned and unreported outages and derates will be consistent with the average of the previous three years' summer peak months during on-peak hours; and
- MISO will only access 75 percent of demand response resources in an emergency, consistent with historical observations.

Table 13: Summer 2026 Planning Reserve Margins

	Base Scenario	Alternative IMM Scenarios [1)]			
		Realistic Base Scenario	Realistic Evening Ramp Scenario	High Temperature Cases: Realistic Scenario	High Temperature Cases: Evening Ramp Scenario
Load					
Base Case	125,531	125,531	125,531	125,531	125,531
Load Adjust			(4,773)	6,339	1,325
Wind & Solar					
Internal Wind & Solar	17,961	17,961	8,485	17,961	8,485
BTM Wind & Solar	1,359	1,359	342	1,359	342
Net-Load (MW)	106,211	106,211	111,931	112,550	118,029
Conventional Generation					
Internal Conventional Generation Excluding Exports	123,731	123,731	123,731	123,731	123,731
BTM Conventional Generation	3,361	3,361	3,361	3,361	3,361
Unforced Outages and Derates [2)]	(1,707)	(8,259)	(8,259)	(15,859)	(15,859)
Adjustment due to Transfer Limit	(11,579)	(4,627)	(1,472)	(650)	-
Total Conventional Generation (MW)	113,806	114,206	117,361	110,583	111,234
Imports and Demand Response [3)]					
Demand Response (ICAP)	9,698	7,274	7,274	7,274	7,274
Firm Capacity Imports	4,729	4,729	4,279	4,729	4,279
Margin (MW)	22,023	19,998	16,983	10,036	4,758
Margin (%)	**17.5%**	**15.9%**	**14.1%**	**7.6%**	**3.8%**
Expected Capacity Uses and Additions					
Expected Forced Outages [4)]	(6,591)	(7,338)	(7,338)	(7,338)	(7,338)
Non-Firm Net Imports in Emergencies	2,867	2,867	2,867	2,867	2,867
Expected Margin (MW)	18,298	15,527	12,512	5,565	287
Expected Margin (%)	**14.6%**	**12.4%**	**10.4%**	**4.2%**	**0.2%**

1) All IMM scenarios assume 75% response from DR. Evening Ramp Scenario reduces solar by approximately 10 GW and firm capacity imports by 450 MW.
2) Base scenario shows approved planned outages for summer 2026. Realistic cases use historical averages during peak summer hours. High temp. cases are based upon MISO's 2026 Summer Readiness.
3) Cleared amounts for the Summer Season of the 2026/2027 planning year.
4) Base scenario assumes 5% forced outage rate for internal, BTM, and external generation (excluding wind and solar). Alternative cases use historical average forced outages/derates during peak summer hours for internal generation.

The planning reserve margin in the base case is 17.5 percent, exceeding the summer ICAP PRM of 15.0 percent. In the realistic scenario, the planning reserve margin falls to 15.9 percent, which is still more than sufficient. We note MISO has substantial import capability from virtually every direction. Only a small amount of this import capability is reserved on a firm basis to import capacity. The remaining capability is available on a non-firm basis to resolve shortages when they occur. Hence, the table includes additional imports equal to the average amount of incremental imports during emergency conditions.[28] This is conservative because import levels would likely rise much more in response to shortage pricing in MISO.

28 These imports are consistent with the non-firm external support assumptions in the 2025-2026 LOLE study.

Evening Ramp Scenario. In this scenario, we evaluate reliability during the evening ramp period, when solar output declines and net load is highest. Although solar generation falls sharply during these hours, this is partially offset by a reduction in the load from the afternoon to the evening; load is also lower than during the summer peak. As a result, the reduction in load partially offsets the loss of solar generation, yielding a planning reserve margin of 14.1 percent.

High Temperature Scenarios. We include two additional variants of the realistic scenarios that reflect hotter-than-normal summer peak conditions. These scenarios are important because hot weather significantly affects both load and supply. High temperatures can reduce the maximum output limits of many MISO generators when outlet water temperatures or other environmental restrictions derate certain resources.[29] On the load side, we assume an approximation to MISO's "90/10" forecast case, which should occur one year in ten.

The high-temperature cases for the realistic scenario and the realistic evening ramp both show that MISO's margin will be reduced after accounting for imports and forced outages, falling to 7.6 percent and 3.8 percent, respectively. In all cases, MISO is expected to maintain a positive margin above 2,400 MW, consistent with its operating reserve requirements.

Overall, these results indicate that the system's resources are adequate for summer even under very hot conditions. Planning reserve margins will likely continue to decrease as fossil-fuel and nuclear resources retire and renewable resources enter. Therefore, the capacity market and shortage pricing must provide efficient economic signals to maintain adequate resources.

D. Capacity Market Results

The purpose of capacity markets is to facilitate long-term investment decisions to satisfy RTOs' planning requirements in conjunction with the energy and ancillary services markets. The economic signals provided by these markets together inform long-term decisions to build new resources and make capital investments in or retire existing resources. MISO's Resource Adequacy Construct allows load-serving entities (LSEs) to procure capacity to meet their Module E requirements through bilateral contracts, self-supply, or the PRA. Resources that clear in MISO's PRA receive capacity revenues that, together with energy and ancillary services market revenues, should signal when new resources are needed.

PRA Results for the 2025–2026 Planning Year

MISO responded to one of our long-standing recommendations by implementing a downward-sloping RBDC in the MISO PRA beginning with the 2025–2026 Planning Year in March 2025. This was MISO's third seasonal auction, the results of which are summarized in Table 15.

29 These high-temperature derates are highly variable, so we assume high-temperature conditions from the MISO high-temperature scenario from its 2020 Summer Assessment.

Table 14: 2025–2026 Planning Resource Auction Results

Season	Capacity Procured	Offered Not Cleared	LOLE Target	Prices ($/MW-Day) Rest of Market	Prices ($/MW-Day) MISO South	Excess Cleared System	Excess Cleared South
Summer 25	137,559	277	0.10	$666.50		1.017	1.008
Fall 25	132,516	4,260	0.01	$91.60	$74.09	1.023	1.002
Winter 25/26	131,000	3,262	0.01	$33.20		1.051	1.075
Spring 26	130,700	5,361	0.01	$69.88		1.012	0.997
PRA Year	132,944	3,290		$215.30	$210.92	1.026	1.021

For the year, market clearing prices averaged nearly $215 per MW-day, ranging from $33.20 to $666.50 per MW-day in the winter to the summer. These prices reflect the prevailing capacity margins—the PRA cleared with a 1.7 percent surplus in summer. Capacity margins have fallen substantially in recent years, partly because low prices under the vertical demand curve that prevailed until this PRA auction precipitated uneconomic retirements of merchant generators.

- 4.6 GW decrease in SAC because the summer UCAP/ISAC ratio fell from 1.04 to 0.99 (i.e., better alignment between LOLE UCAP and unit availability during RA hours);
- 1 GW increase in Planning Reserve Margin Requirement (PRMR);
- 2.9 GW of thermal capacity suspensions/retirements; and
- 0.5 GW drop in offers from external resources.

Non-thermal accreditation increased by 5 GW with the addition of new solar, but it did not offset the combined impacts of the capacity losses and additional demand.

Resettlement of the 2025–2026 Capacity Auction

Unfortunately, after posting the PRA results, MISO discovered a modeling error in its LOLE assumptions[30] that affected the RBDC and concluded that it needed to resettle the capacity auction in August 2025. The PRA set efficient prices that corresponded to MISO's actual reliability standard of loss of load of no more than "one day in 10 years." However, the resettlement was based on an auction that would have targeted closer to a "one day in 5 years" standard. The resettlement was harmful to the integrity of the competitive markets and was inconsistent with the information posted before the auction that participants used to make resource and contracting decisions.

PRA Results for the 2026–2027 Planning Year

MISO held its second capacity auction under the seasonal RBDC construct in March 2026. The results for the 2026–2027 PRA are summarized in Table 15.

30 A flawed definition in Module A of MISO's Tariff called for an LOLE calculation that corresponded to a much lower level of reliability, less than one day in five years.

Table 15: 2026–2027 Planning Resource Auction Results

Season	Capacity Procured	Offered Not Cleared	LOLE Target	Prices ($/MW-Day)			Excess Cleared	
				Rest of Market	Zone 9	Zones 8,10	System	South
Summer 26	142,374	179	0.10	$424.30	$412.10	$384.10	1.032	1.017
Fall 26	133,629	5,321	0.01		$33.92		1.051	1.065
Winter 26/27	131,979	2,759	0.01		$35.97		1.035	1.099
Spring 27	135,267	6,422	0.01		$7.61		1.038	1.080
PRA Year	135,839	3,671		$126.19	$123.12	$116.06	1.039	1.065

Across the four seasons, market clearing prices averaged nearly $126 per MW-day, ranging from $7.61 per MW-day in the spring to $424.30 per MW-day in the summer. These prices reflect the prevailing reliability value of capacity in MISO, which cleared with a 3.2 percent surplus in the summer. Although the summer PRMR increased by 2.7 GW from the 2025–26 auction, summer clearing prices fell by approximately $240 per MW-day because :

- 1.5 GW net increase in dispatchable generation, as new and replacement resources outpaced retirements and suspensions;
- 1 GW increase in external resource participation
- 3.4 GW of new solar capacity; and
- an additional 1.3 GW increase in the accreditation of existing solar resources.[31]

The higher prices in the previous auction likely prompted some of this increased participation and delayed some retirement decisions. The 2026–2027 results under RBDC continue to send strong economic signals, which is critical because large loads continue to increase. Had the auction run under a vertical demand curve construct, the summer clearing price would have been only $1 per MW-day, which would have deterred investment and encouraged retirements.

Nonetheless, the clearing prices were inefficiently low in the 2026–2027 PRA because existing solar resources were over-accredited. Accreditation of existing solar resources in the non-winter seasons is based on output from 2 pm to 5 pm, which produces an average accreditation of 68 percent. This is roughly double the accreditation that will prevail under DLOL accreditation to be implemented in 2028. The hours used for this accreditation are misaligned with reliability risks, which increasingly occur later in the day when solar output is falling.

Using evening hours, such as from 4 pm to 7 pm, would better align accreditation with the system's reliability needs and produce accreditation levels more consistent with the 50 percent assigned to new solar resources. We simulated the change and found that accreditation of existing solar resources would have fallen by 2.6 GW and prices in the summer would have been

31 Summer accreditation for existing solar is based on average historical performance during hours ending 15, 16, and 17 (See Appendix V of BPM-011). Existing solar resources under this methodology have been outperforming the initial 50 percent accreditation generally assigned in the first year of entry.

50 percent higher. This accreditation distortion will increase to well over 3 GW next year because new solar resources that entered in the prior year will become existing resources and see their accreditation grow from 50 percent to close to 70 percent. Hence, we recommend implementing this change for the 2027–2028 PRA, prior to implementation of DLOL in 2028.

Other Issues Affecting PRA Performance

Transfer Constraint. As part of the Settlement Agreement with SPP and the Joint Parties, MISO may dispatch up to 2,500 MW of energy transfers from MISO South to MISO Midwest. However, in the PRA, MISO limits transfer capability in the South-to-North direction to 1,900 MW. MISO mistakenly believes this reduction is necessary to account for firm interregional transmission reservations, even though the reservations do not encumber MISO's use of the RDT. We recommend that MISO increase the limit to reflect expected transfer capability closer to 2,500 MW. This would more accurately reflect its ability to access capacity in MISO South during tight conditions or emergencies.

E. Long-Term Economic Signals

Price signals in MISO's markets play an essential role in coordinating unit commitment and dispatch in the short term while providing long-term economic signals for investment and retirement decisions for generators and transmission facilities. This subsection evaluates those signals by measuring "net revenue"—the revenue a unit earns above its variable production costs when it is economic to run.

Well-designed markets produce net revenues sufficient to support new investment when existing resources are not adequate to meet the system's needs. Figure 36 and Figure 37 show estimated net revenues for new combustion turbine (CT) and combined-cycle (CC) units for the last three years in the Midwest and South subregions. The figures also show the annual net revenue needed for these investments to be profitable (the Cost of New Entry, or "CONE"). The blue bars indicate the net revenues that would have been realized in different locations, while the green bars show the contribution of ancillary services revenues. The maroon bars show the contribution from capacity market revenues, and the ghost bars indicate the impacts of MISO's resettlement of the 2025–2026 capacity auction.

These figures show that net revenues increased markedly for both technologies in all zones in 2025, driven by higher energy and ancillary services revenues, as well as substantially higher capacity revenues under the new sloped RBDCs. The increase in energy net revenues for these gas resources was driven by more frequent summer hot weather events relative to 2024. The ghost bars indicate that the capacity market resettlement significantly affected both resource technology types in all regions. In most regions, investment signals indicate that building new resources would be economic, with the exception of the South region outside of Louisiana.

Figure 36: Net Revenue Analysis
Midwest Region, 2023–2025

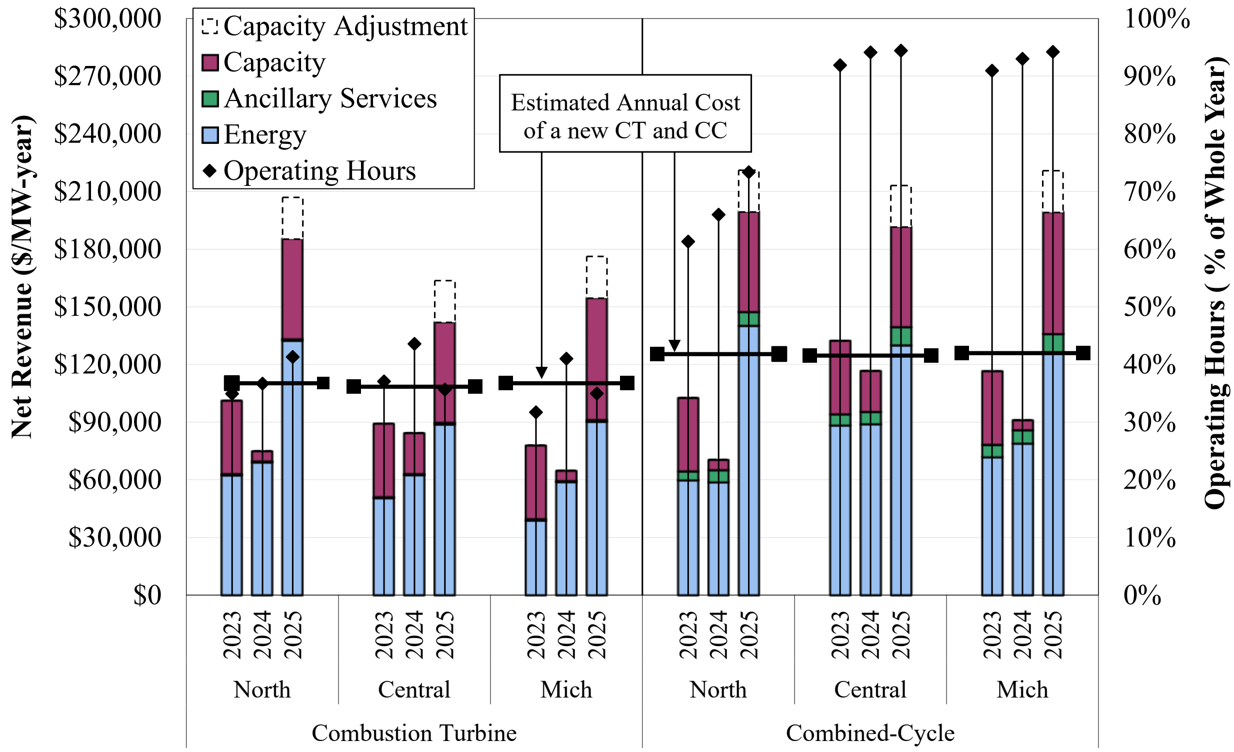
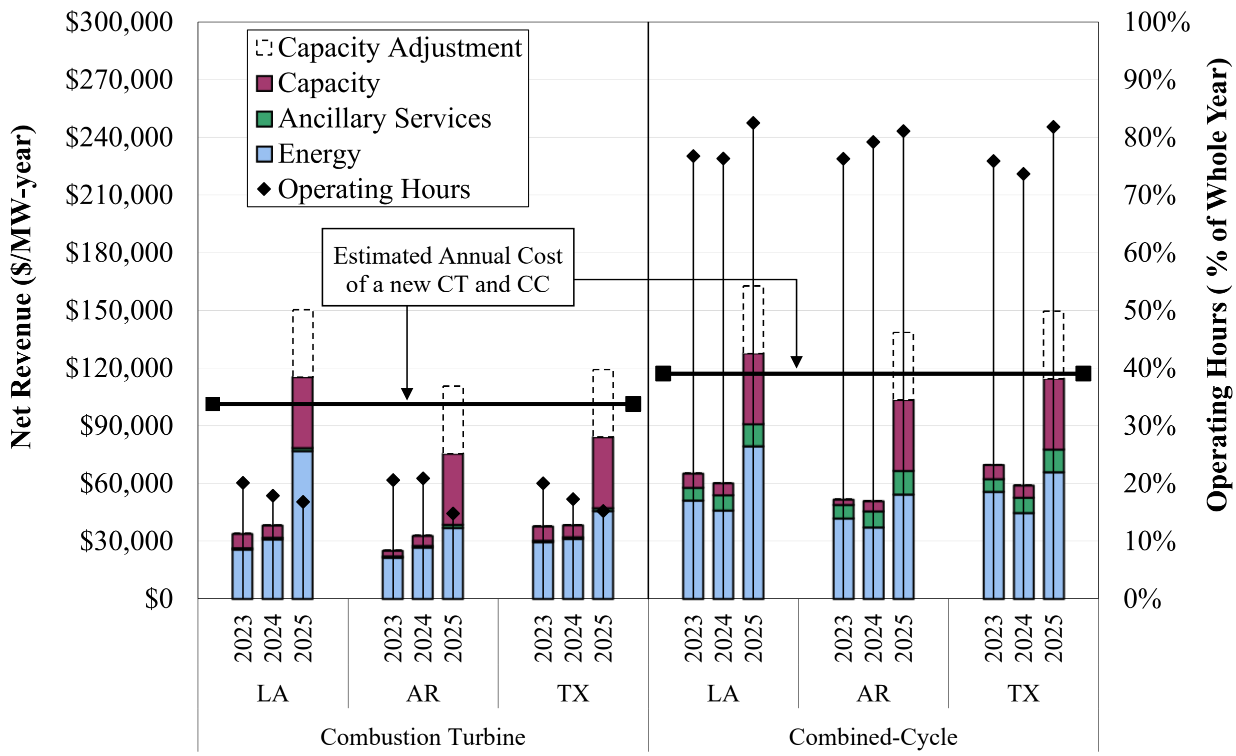


Figure 37: Net Revenue Analysis
South Region, 2023–2025



F. Capacity Market Reforms

Although adopting a reliability-based demand curve and improving capacity accreditation have been the most important design improvements, we have also recommended that MISO consider the following additional improvements to provide better incentives to MISO's suppliers in the long term and ensure that MISO satisfies its resource adequacy needs.

Improvements to the Seasonal Market

In MISO's 2022 SAC filing, we raised issues with elements that we believed reduced the benefits of the two broad changes (seasonal market and accreditation based on tight hours):[32]

- The seasonal design clears all four seasons simultaneously at the beginning of the planning year. We recommended that MISO run auctions before each season so participants can optimize their offers for the next season based on prior results; and
- The implemented design still generally overvalues inflexible resources, such as offline units with 24-hour lead times, by accrediting them comparably to online or fast-starting resources.

We will be working with MISO in the coming years to evaluate the benefits of making improvements to address these issues.

Capacity Replacement Settlements

Under MISO's current Resource Adequacy construct, market participants with capacity obligations must buy replacement Zonal Resource Credits (ZRCs) that match the scale, zone, and duration of their outages or incur Capacity Replacement Non-Compliance Costs (CRNCC) if their resources are on planned outage for more than 31 days in a season. The 31-day penalty threshold creates inefficient incentives to "straddle" outages across seasonal boundaries because of the 31-day grace period before CRNCC penalties apply. We have observed outages increasingly being scheduled in the first and last 30 days of the fall and spring seasons. This pattern is consistent with attempts to avoid CRNCC exposure.

Additionally, long-duration or large outages under this framework can require market participants to engage in bilateral contracts with multiple counterparties. In contrast, a liquid and transparent market with prices that reflect daily reliability conditions throughout a season would allow market participants with units on outage to buy replacement capacity quickly, enabling prudently timed outages with a shorter lead time and lower compliance costs, or to forego replacement when the system has abundant capacity.

32 See *Motion to Intervene out of Time and Comments of the MISO IMM under ER22-495*.

To address the issues described above and provide participants improved outage scheduling incentives, we propose a new Capacity Replacement Settlement (CRS) to replace the CRNCC framework. The CRS is a transparent, market-based alternative to the CRNCC that will:

- Address concerns related to the costs and administrative burden of the current rules; and
- Set a price of replacement capacity—ZRCs purchased by resources to fulfill their PRA obligations during outages—that reflects system reliability conditions.

Such a settlement could offer market participants streamlined compliance and low capacity-replacement costs for much of the year. The CRS market could also offer new paths to capacity revenue. Resources with uncleared ZRCs could meet demand for replacement capacity transparently and efficiently. Under this construct, the price of replacement capacity would vary with system conditions, providing an incentive to schedule outages in periods of low reliability risk, reducing the probability of forced outages during high reliability risk periods when the system most needs capacity.

We conducted an analysis estimating illustrative prices that would have cleared this capacity replacement market each day from March 1, 2025 through February 28, 2026 for the Midwest and South, which appears in Section VI.F of the Analytic Appendix where we also provide more details about the demand and supply-curve assumptions and methodology. These results show that market participants could have procured capacity at little to no cost during much of the study period.

However, outages on days when capacity was scarcest would have been markedly more expensive and well over $6,000/MW-day, reflecting the higher reliability value of capacity on those days. This would cause resources on long-duration outages during most of the tightest days in the summer to incur charges that would be comparable to the capacity revenues they were originally paid.

Capacity Accreditation Improvements

We have also identified two issues that can distort the accreditation of some resources:

- MISO’s maintenance margin for approving exempt planned outages is inaccurate. The exemptions prevent such outages from affecting a resource’s accreditation.
- The accreditation rules do not recognize that the capacity above the current output level from resources operating off-control is not available to the system.

MISO’s maintenance margin has two main flaws. First, the load input is the average daily load from the 30 weather years used in the LOLE studies. However, the difference between an average and peak summer day is about 15 GW in the Midwest and 18 GW market wide. Therefore, using the average load inflates the maintenance margin. Second, MISO’s treatment of suspending or retiring resources and new resources in the interconnection queue also tends to inflate the maintenance margin.

The accreditation rules do not currently account for resources running “off control”. When a unit is off-control, it does not respond to dispatch instructions, and the output above its current operating level is unavailable to the system. Effectively, the unit is derated to its current output level. Although the accreditation rules account for deratings, they assume off-control resources are fully available up to their emergency maximum value. We recommend that MISO close this loophole by using the actual output level in the accreditation calculations for resources operating off-control. This will ensure that resources that cannot or will not provide flexibility during the hours of highest need do not receive more capacity credit than they provide.

Other Recommended Improvements to the PRA

Accreditation of Emergency Resources. Emergency-only resources, including LMRs and Available Max Emergency (AME) resources, are only required to deploy during emergencies when MISO instructs them to do so. If they are unavailable to mitigate capacity shortages during emergencies, they do not provide the reliability value MISO assumes and compensates them for. Some emergency-only resources have long notification times (up to 12 hours) or long start-up or shutdown times, making them essentially unavailable in most emergencies, which tend to occur with less than two hours’ warning. Therefore, we recommended that MISO develop a reasonable methodology to accredit emergency-only resources in the PRA.

In 2025, MISO filed Tariff changes to reform LMR and emergency-only resource accreditation and better align them with the Direct Loss of Load (DLOL) accreditation methodology that MISO will implement in the 2028–2029 Planning Year.[33] These changes, along with earlier reforms, should address our recommendation.

Modeling Transmission Constraints in the PRA. MISO currently only models import and export limits for each zone and the RDT transfer constraint from South to North. After the initial PRA solution, it runs a power-flow model to determine whether any constraints are binding. Although transmission constraints have not been prevalent in the past, this is a poor approach that will not efficiently price constraints that arise. Instead, MISO should model these constraints in the PRA by assigning each modeled constraint a zonal shift factor that reflects how resources in each zone affect flow on the constraint. This change would allow zonal prices to accurately reflect those constraints.

33 Docket No. ER22-495-000.

VII. External Transactions

A. Overall Import and Export Patterns

Imports and exports play a key role in MISO because its 12 interfaces with neighboring systems have total interface capability greater than 15 GW. Therefore, changes in imports and exports in response to prices can be large and can significantly affect market outcomes. Interface price differences incentivize physical schedulers to import and export between MISO and adjacent areas. Although average hourly imports fell from last year, MISO remained a net importer in 2025:

- Day-ahead and real-time hourly net scheduled interchange (NSI) averaged 2.3 and 1.8 GW, respectively (positive NSI values indicate net imports), down from 2.4 and 2.6 GW.
- MISO's largest and most actively scheduled interface is the PJM interface. MISO continued to be a net importer from PJM in 2025.
  - Hourly real-time imports from PJM averaged 2.0 GW, representing an 8 percent increase from 2024.
  - Some scheduling patterns between MISO and PJM were inefficient because of flaws in the RTOs' interface prices, as discussed below.
- For the first time in recent years, MISO was a net exporter to Manitoba in 2025. Net exports averaged 75 MW per hour because of drought conditions in Canada.
- In May 2025, the IESO (Ontario) introduced Locational Marginal Pricing and a financially binding day-ahead market. Since then, price volatility in that market has increased, and NSI has decreased somewhat.

Scheduling that responds to interregional price differences captures substantial savings because lower-cost resources in one area displace higher-cost resources in the other. Participants must schedule transactions at least 20 minutes in advance and therefore must forecast price differences. Because RTOs do not coordinate external transactions, aggregate transaction changes are far from optimal. To evaluate the efficiency of external scheduling, we track the share of transactions that were profitable (i.e., scheduled from the lower-priced market to the higher-priced market), reducing total production costs in both regions.

Markets respond to price signals when determining interchange levels. We studied this response in 2025 and found that sustained prices over $100 per MWh prompted changes in net imports averaging 400 MW one hour later, while prices over $400 per MWh prompted changes averaging 1,150 MW. Nonetheless, large savings often go untapped because it is often economic to schedule significantly more or less interchange. In 2025, over 60 percent of transactions with PJM and over 67 percent of transactions with SPP were scheduled in the profitable direction. Many hours still exhibit large price differences that imply substantial unrealized production cost savings.

B. Coordinated Transaction Scheduling

On October 3, 2017, MISO and PJM implemented Coordinated Transaction Scheduling (CTS). CTS allows market participants to submit offers to schedule imports or exports between the RTOs within the hour. Offers clear if the forecasted spread between the RTOs' real-time interface prices 30 minutes before the interval exceeds the offer price. CTS transactions settle on real-time interface prices. This subsection discusses the performance of the current CTS system and a fundamental reform that would improve it substantially.

Summary of CTS Performance

Until early 2019, there was almost no participation in CTS and subsequently participation has been very low. In 2025, the hourly average quantity of CTS transactions offered and cleared remained extremely low at 100 MW and 30 MW, respectively. Over 99 percent of transactions over the past two years have been in the import direction. CTS transactions remain a *de minimis* fraction of transactions at the PJM interface and the CTS framework is providing very little benefit to MISO. Our evaluation finds two primary reasons for this:

- Transmission reservation and usage charges likely deterred traders from using CTS instead of traditional transaction scheduling; and
- Persistent forecasting errors by MISO and PJM hinder the use of CTS. PJM's forecasts are particularly poor with an average error of -33 percent and an average absolute error (regardless of the direction of the error) of 54 percent.[34]

These errors severely limit CTS's effectiveness by creating large risks for CTS participation because CTS would likely often schedule transactions that are uneconomic based on real-time price spreads. In 2026, MISO proposed eliminating the product and consider replacing it with a more efficient alternative. This was based on the low participation in CTS and the high cost of transitioning CTS to its Market Clearing Engine (MCE).

Replacing CTS with Interchange Optimization (IO)

Interchange optimization is a process to adjust the interchange in real time to converge prices between markets. Such a process can deliver enormous economic and reliability benefits, particularly in periods when one market is short of energy or operating reserves. For example, MISO has been periodically experiencing transitory energy shortages resulting in prices as high as $10,000 per MWh during the evening net load ramp period when solar output is falling rapidly. Prices in SPP are frequently $30 to $40 per MWh during these periods and the shortage in MISO could be eliminated by adjusting the real-time interchange between the markets. The same conditions can and do occur in reverse. This section describes straightforward method for implement IO that would not be resource intensive.

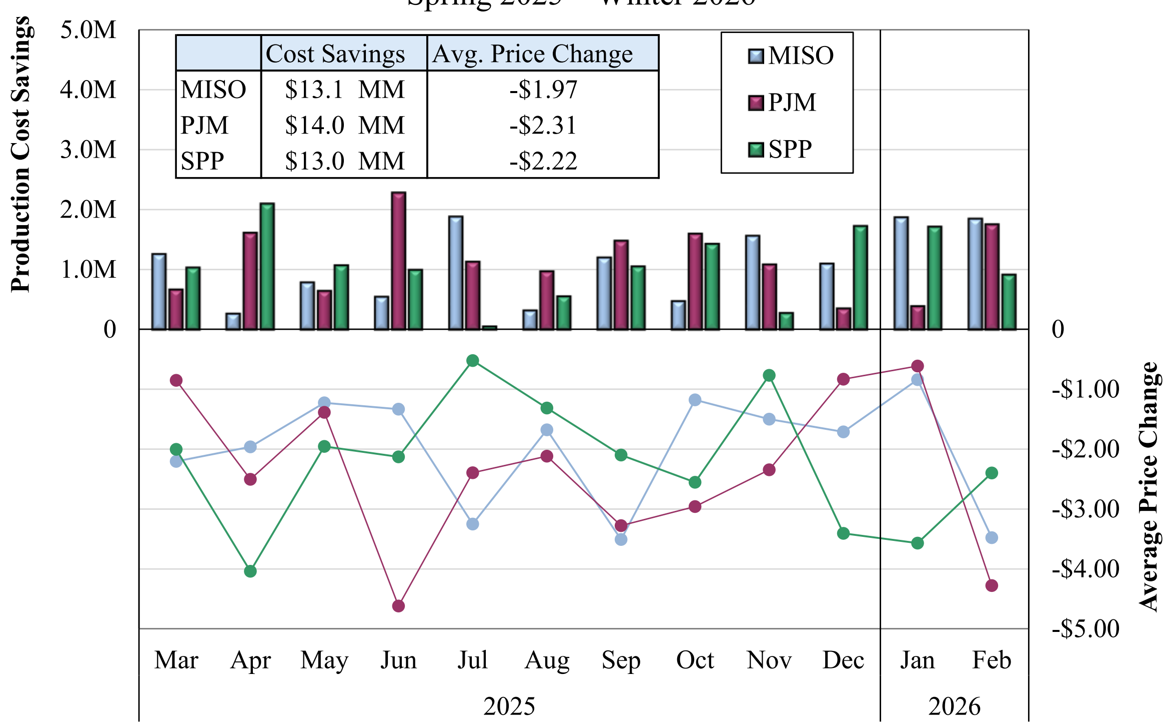
34 PJM's forecast prices are from its intermediate term security-constrained economic dispatch tool (IT SCED).

MISO solves its real-time Unit Dispatch System (UDS) every five minutes. Because the dispatch model takes 90 seconds to solve, target generation demand can change materially during that time. To address this demand variability, MISO runs six scenarios with different load targets. After the scenarios complete, the UDS operator approves the one that best approximates the market's needs. This decision incorporates Area Control Error (ACE), regulation deployment, generator status changes, and the base forecasted demand. PJM and SPP use similar real-time case approval processes.

MISO, PJM, and SPP could leverage their alternate real-time case results to coordinate interchange more efficiently. They could exchange and evaluate data from the alternative load scenarios, including production cost changes and interface LMPs, to minimize aggregate production costs across markets. An IO clearing process would be simple to implement and could be configured to each RTO's preference.

We analyzed IO production cost savings and price effects. Because PJM and SPP did not provide alternate load scenario results, we estimated external price changes for alternative load scenarios. This statistical exercise assumed that the external areas had supply characteristics and price elasticities similar to MISO's. Figure 38 shows the estimated production cost savings and average price effects in each market in the 12 months from Spring 2025 through Winter 2026.

Figure 38: Interchange Optimization Benefit Estimate
Spring 2025 – Winter 2026



The estimated $40 million in benefits was spread evenly across the three markets. Prices in each market declined by $1.97 to $2.31 per MWh. Total cost savings to load would be much higher than the production cost benefit. Across MISO, a two dollar decrease in LMP would lower the annual market cost of energy by almost $1.4 billion.

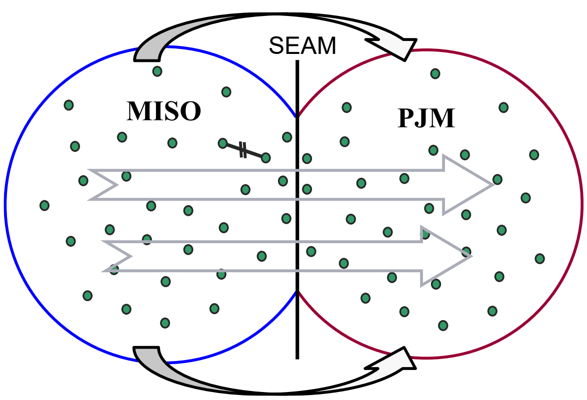
C. Interface Pricing and External Transactions

Each RTO posts its own interface price to settle physical schedules to sell power to and buy power from the neighboring RTO. Participants schedule flows between the RTOs to arbitrage differences between the two interface prices. Interface pricing is essential because:

- It solely facilitates efficient power flows between RTOs;
- Poor interface pricing can lead to significant uplift costs and other inefficiencies; and
- It is essential for CTS to maximize interface utilization.

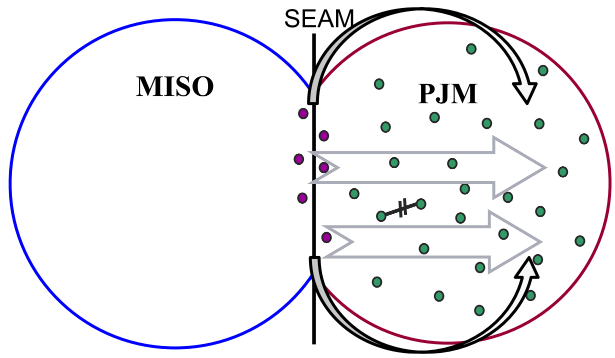
Establishing efficient interface prices would be simple without transmission congestion and losses—each RTO would post the interface price as the cost of the marginal resource on its system (the system marginal price, or "SMP"). Participants would then schedule power from the lower-cost system to the higher-cost system until the SMPs equalize. However, because congestion is pervasive on these systems, the fundamental issue in interface pricing is estimating the congestion costs and benefits of imports and exports.

Like the LMP at all generation and load locations, the interface price includes: a) the SMP, b) a marginal loss component, and c) a congestion component. For generator locations, the source of the power is known and, therefore, congestion effects can be calculated accurately. In contrast, *the source of an import (or sink for an export) is not known*, so it must be assumed to calculate the congestion effects. This is known as the *"interface definition".* If the interface definition reflects the actual source or sink of the power, the interface price will incentivize efficient transaction scheduling and lower costs for both systems.



When power moves from one area to the other, generators ramp up throughout one area and ramp down throughout the other area (marginal units), as shown in the figure to the left. This figure is consistent with MISO's interface pricing before June 2017, which calculated flows for exports to PJM based on power sinking throughout PJM. This is accurate because PJM ramps down its marginal generators when it imports power. Because both RTOs price congestion on M2M constraints, MISO and PJM and MISO and SPP redundantly priced some congestion.

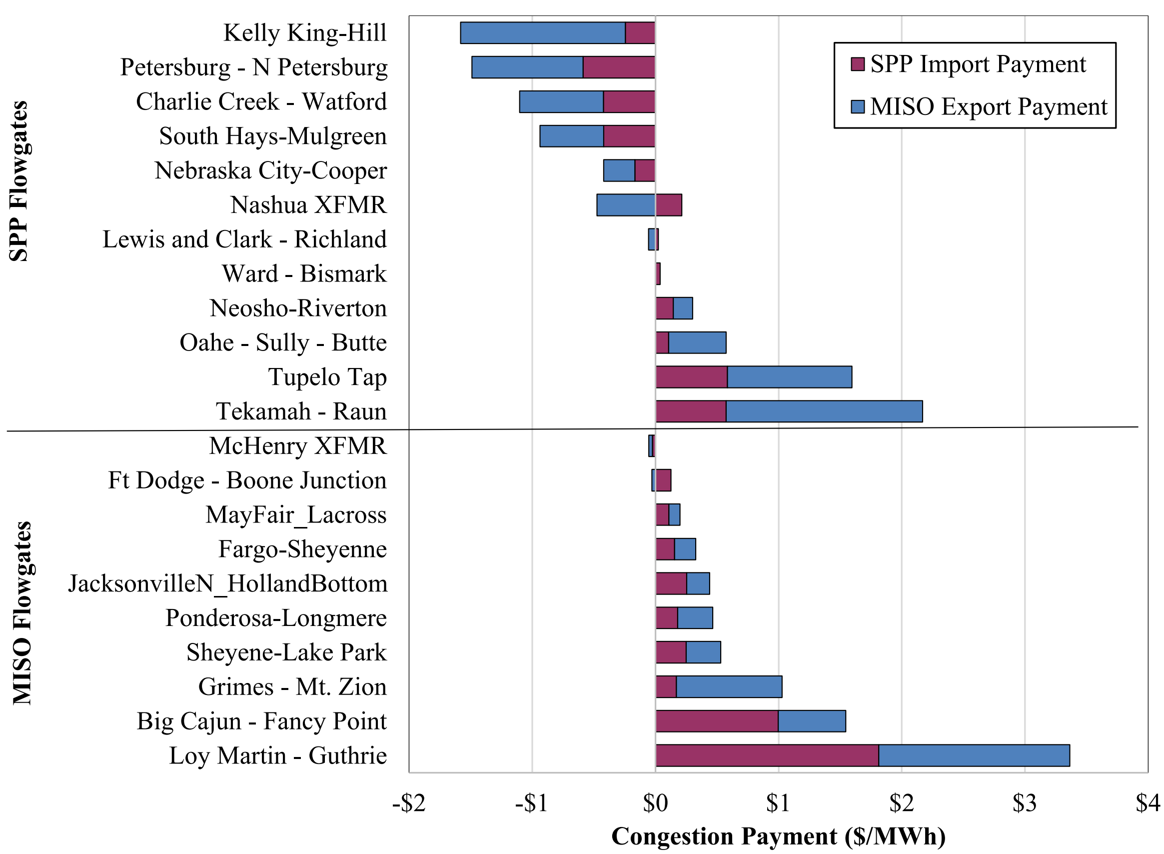
To address this concern, PJM and MISO agreed to implement a "common interface" that assumes power sources and sinks at the border with MISO, as shown in the second figure to the right. This common interface consists of 10 generator locations near the PJM seam: five points in MISO's market and five in PJM. This approach tends to exaggerate the flow effects of imports and exports on constraints near the seam because it underestimates the amount of power that will loop outside the RTOs.



Our evaluation confirms that MISO's marginal generators are distributed *throughout* MISO, causing the common interface definition to produce inefficient interface prices. Our studies show that, in aggregate, the common interface has led to larger errors and greater volatility at the interface. Fortunately, MISO uses this type of interface definition only at the PJM interface, whereas PJM uses it on all its interfaces.

We have studied interface pricing at the MISO-SPP interface and verified that redundant congestion pricing is still occurring because of the overlapping interface definitions. To illustrate this outcome, we calculated the average interface pricing component for selected M2M constraints. Figure 39 shows the congestion component that SPP and MISO calculated for each constraint, with MISO constraints and SPP constraints shown separately.

Figure 39: Constraint-Specific Interface Congestion Prices



The redundant settlement occurs because when a M2M constraint binds, both RTOs price and settle external transactions based on their respective estimates of the transaction's congestion effects. These estimates are typically similar, which roughly doubles the congestion settlement.

Figure 39 displays the congestion payments as the settlement of an export transaction from MISO to SPP. A negative value indicates that the participant would be charged, whereas a positive value indicates that the participant would be paid for congestion relief. The figure shows that both RTOs estimate very similar effects for each jointly managed constraint. Unfortunately, this causes congestion payments and charges that are roughly double the efficient level—the payment made by the MRTO. In some intervals, the distortions exceed $30 per MWh. This creates poor incentives to schedule imports and exports when M2M constraints are binding and increases costs for the RTOs. In particular, the NMRTO receives no credit in the M2M settlement of any congestion payment it makes, so the costs of these payments must be recovered through uplift charges made to their customers.

To address this issue, we recommend that the RTOs employ their current interface definitions, but include M2M constraints modeled by both RTOs only in the MRTO's interface price.

Interface Pricing for Other External Constraints

In addition to PJM and SPP M2M constraints, MISO also activates constraints in external areas when neighboring system operators call TLRs, obligating MISO to redispatch its generation. External constraints should be reflected in MISO's market models and internal LMPs because that enables MISO to respond efficiently to TLR relief requests. However, MISO is not obligated to pay importers and exporters that may relieve constraints in external areas. In fact, real-time physical schedules are excluded from MISO's market flow, so MISO gets no credit for any relief from its external transactions and no reimbursement for the millions of dollars in costs it incurs each year. Hence, it is inequitable for MISO's customers to bear these costs.

Beyond this inequity, these congestion payments incentivize participants to schedule transactions inefficiently for two reasons:

- In most cases, beneficial transactions are already being fully compensated by the area in which the constraint is located. MISO's additional payment is excessive and inefficient.
- MISO generally vastly overstates the external TLR constraints in its pricing and creates inefficient scheduling incentives.

Fortunately, this issue is easy to address. Since 2012, we have recommended that MISO simply remove congestion related to external constraints from each interface price. This change would resolve the interface pricing issue for all of MISO's other interfaces, excluding the PJM and SPP interfaces.

VIII. Competitive Assessment and Market Power Mitigation

This section presents our competitive assessment of the MISO markets, including a review of market power indicators, an evaluation of participant conduct, and a summary of market power mitigation measures that occurred in 2025. Market power in electricity markets exists when a participant can materially change market clearing prices. Various empirical measures can indicate market power in electricity markets, and we discuss them in this section.

A. Structural Market Power Indicators

Economists and antitrust agencies often use market concentration metrics to evaluate a market's competitiveness. The most common metric is the Herfindahl-Hirschman Index (HHI), calculated as the sum of each supplier's squared market share. An HHI below 1000 is generally considered low, while an HHI above 1800 is considered high. Market concentration is low for the overall MISO area (517) but very high in some local areas, such as WUMS (4407) and the South Region (3187), where a single supplier operates about 55 percent of the generation. However, HHI does not include the effects of load obligations, which affect suppliers' incentives to raise prices. HHI also does not account for the difference between total supply and demand. This difference is important because excess supply results in more competitive markets. Hence, HHI is a limited indicator of overall competitiveness.

A more reliable indicator of potential market power is whether a supplier is "pivotal", meaning its resources are necessary to satisfy load or manage a constraint. Our regional pivotal supplier analysis indicates that pivotal supplier frequency rises sharply with load. This is typical in electricity markets because electricity cannot be stored economically. Hence, as load increases, excess capacity falls, and large suppliers' resources may be needed.

We also evaluate local market power by identifying pivotal suppliers that can relieve transmission constraints into constrained areas, including the five Narrow Constrained Areas (NCAs) and all Broad Constrained Areas (BCAs). NCAs are chronically constrained areas that raise more serious local market power concerns and employ tighter market power mitigation measures. A BCA is defined by binding non-NCA transmission constraints and includes all generating units that significantly affect power flows over the constraint. Our results show that a supplier was frequently pivotal in 2025 in both types of constrained areas:

- On average, 59 percent of the active BCA constraints had at least one pivotal supplier.
- Over 90 percent of binding constraints into the MISO South NCAs and the Midwest NCAs had at least one pivotal supplier.

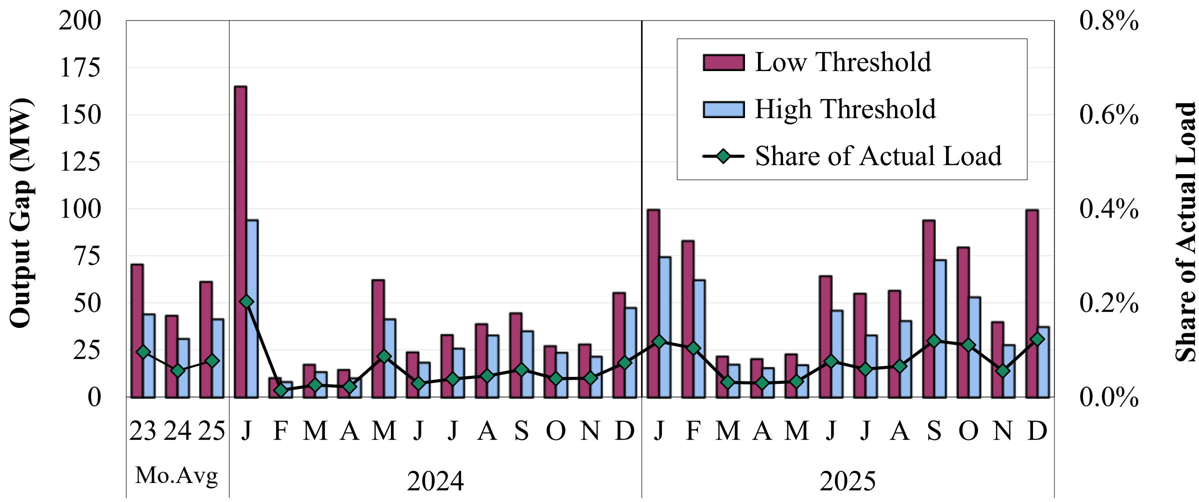
Overall, these results indicate that local market power persists for both BCA and NCA constraints and that market power mitigation measures remain critical.

B. Evaluation of Competitive Conduct

Despite these indicators of structural market power, our analyses of participant conduct show little evidence that participants physically or economically withheld resources to exercise market power. Aggregate measures of overall market competitiveness, including the "price-cost mark-up," confirm this finding. This measure compares the system marginal price based on actual offers with a simulated system marginal price assuming all suppliers submitted offers at their estimated marginal cost. We found an average system marginal price-cost mark-up of -1.07 percent in 2025. The very small, negative mark-up indicates that the markets were highly competitive overall.

Figure 40 shows the "output gap" metric we use to detect potential economic withholding. The output gap is the quantity of power not produced by resources whose operating costs are more than a threshold amount below the LMP. We perform the output gap analysis using the Tariff's conduct threshold (the "high threshold") and a "low threshold" equal to one-half of the conduct threshold. The output gap includes units that are online and submit inflated energy offers, as well as units that were not committed because of inflated economic or physical offer parameters.

Figure 40: Economic Withholding – Output Gap Analysis
2024–2025



Low Threshold Results by Unit Status (MW)

Offline	55	31	44	98	3	8	6	56	18	25	31	37	22	24	49	71	62	13	13	16	42	31	43	84	71	32	45
Online	15	12	18	66	7	10	9	6	6	8	7	8	6	4	7	28	21	9	8	7	22	24	13	10	8	8	54

High Threshold Results by Unit Status (MW)

Offline	39	26	35	84	3	6	4	38	14	22	29	31	20	19	44	66	56	12	11	13	35	24	34	69	48	24	34
Online	5	5	6	9	6	7	6	4	5	4	4	4	4	3	3	9	6	5	4	5	11	9	6	4	5	4	4

The figure shows the average monthly output gap level was 0.08 percent of load in 2025, which is effectively *de minimis*. Although these results raise no competitive concerns, we monitor output gap levels hourly and routinely investigate potential withholding.

C. Summary of Market Power Mitigation

Market power mitigation in 2025 effectively limited the exercise of market power. Mitigation in the energy market remained infrequent. In MISO's energy market, automated conduct and impact tests apply clearly specified criteria. For economic withholding, the mitigation measure caps a unit's offer price when the offer exceeds the conduct threshold and substantially raises energy market clearing prices or RSG payments. Because conduct has generally been competitive, MISO has imposed market power mitigation infrequently. The mitigation thresholds differ for the three types of constrained areas that may be subject to mitigation:

- Broad Constrained Areas (BCAs);
- Narrow Constrained Areas (NCAs); and
- Dynamic NCAs are transitory constrained areas that can occur when outages create severe congestion.

Market power concerns are greatest in NCAs and Dynamic NCAs because they address chronic or severe congestion. As a result, conduct and impact thresholds for NCAs and Dynamic NCAs are much lower than for BCAs. NCA thresholds depend on how frequently the constraints bind, while Dynamic NCAs use a fixed threshold of $25 per MWh. No Dynamic NCAs were declared in 2025. The lower NCA thresholds generally lead to more frequent mitigation in NCAs, even though there are many more BCAs.

Market power mitigation in MISO's energy market remained infrequent because conduct was generally competitive. The incidence of mitigation remained very low in 2025, affecting less than one percent of real-time market hours across 32 days, up from 18 days in 2024. If the real-time market is effectively mitigated, the day-ahead market should not be vulnerable to market power abuse as long as it is liquid and has fulsome participation by physical and virtual trading participants. Accordingly, mitigation was applied on three day-ahead market days in 2025, down from seven in 2024.

However, suppliers can exercise market power when their generation is needed to address reliability issues, extracting rents through RSG payments. RSG payments occur when a resource is committed out-of-market to meet system capacity needs, local reliability requirements, or manage congestion. If a resource's offers include inflated economic or physical parameters, they may inflate RSG payments, and the resource may be mitigated. Commitments to satisfy system-wide capacity needs are not subject to mitigation because competition to satisfy those needs is generally robust.

Average mitigation of day-ahead and real-time RSG payments was 50 and 24 percent lower, respectively, in 2025 than in 2024, largely because MISO mitigated multiple resources in the day-ahead market during Winter Storm Heather in January 2024.

IX. Demand Response

Demand Response (DR) involves actions by electricity consumers to reduce consumption when the value of consuming electricity is less than the prevailing marginal cost of supply. DR is valuable because it contributes to improved operational reliability in the short term and lowers resource adequacy costs in the long term.

Even modest reductions in consumption by end-users during high-priced periods can greatly reduce the costs of committing and dispatching generation. These benefits underscore the value of facilitating efficient DR through wholesale market mechanisms and transparent economic signals. However, DR implementation must be done carefully to avoid creating inefficient incentives for DR resources and gaming opportunities.

This section discusses the current level of DR participation and identifies significant concerns related to MISO's approach to incorporating these demand resources in the market.

A. Demand Response Participation in MISO

Table 16 shows DR participation in MISO and compares it with NYISO and ISO-NE over the last three years. In MISO, DR resources fall into one or more of the following three categories:[35]

- Load-Modifying Resources (LMRs), capacity resources that must curtail in emergencies and satisfy Planning Reserve Margin Requirements (PRMR);
- Demand Response Resources (DRRs) that respond economically to prices in the energy and ancillary services markets; and
- Emergency Demand Response Resources (EDRs) that MISO calls in emergencies but that need not offer and do not satisfy PRMR.

Table 16 shows that MISO had over 14 GW of DR capability available in 2025, more than 1 GW higher than in 2024. Energy Efficiency (EE) participation in the PRA remained very low in 2025, and FERC approved MISO's Tariff provisions that eliminate EE participation beginning in the 2026–2027 Planning Year.

MISO's demand response capability constitutes more than ten percent of peak load, a much larger share than in NYISO but slightly smaller than in ISO-NE. Its resources exhibit varying degrees of responsiveness. Nearly 95 percent of MISO's DR is LMRs, capacity resources comprised primarily of (i) interruptible loads originally developed under regulated utility programs or more recently through aggregators and (ii) behind-the-meter generation. Aggregators of Retail Customers (ARCs) are a growing share of MISO's LMRs in recent years.

35 Some DR may participate in more than one category, depending on the resource capability and responsibilities the resource is willing to accept, as explained below.

Table 16: Demand Response Capability in MISO and Neighboring RTOs
2023–2025

		2023	2024	2025
MISO[1]		**12,311**	**12,979**	**14,067**
	LMR-BTMG	4,129	4,143	4,283
	LMR-DR	7,695	8,109	9,004
	LMR-EE	5	23	28
	DRR Type I	521	692	733
	DRR Type II	79	75	75
	Total Cross-Registered as LMR	*201*	*208*	*137*
	Emergency DR	686	788	706
	Total Cross-Registered as LMR	*603*	*643*	*624*
NYISO[2]		**1,294**	**1,435**	**1,206**
	Special Case Resources - Capacity	1,282	1,433	1,206
	Emergency DR	12	2	0
	Day-Ahead DRP	0	0	0
ISO-NE[3]		**3,798**	**3,674**	**3,257**
	Active Demand Capacity Resources	438	431	352
	Passive Demand Resources	3,360	3,243	2,905

* All units are MW.
[1] Registered as of July for each year.
[2] Registered as of July for each year. Source: Annual Report on Demand Side Management Programs of the New York Independent System Operator, Inc., Docket ER01-3001.
[3] Capacity supply obligations as of July 2025. Source: ISO-NE Monthly Market Reports.

A second category is Demand Response Resources (DRRs), which can participate in MISO's capacity, energy, and ancillary services markets. A third category is Emergency Demand Response (EDR). Currently, resources may cross-register as LMRs and DRRs or EDRs. However, in 2025 FERC approved eliminating LMRs cross-registered as EDRs beginning in June 2026 as part of a broader effort to reform DR participation rules in MISO.

LMRs

LMRs are planning resources that sell capacity and therefore have an obligation to curtail during emergencies. MISO may deploy these resources only during a declared emergency. Many LMRs are legacy demand-side programs administered by regulated utilities, such as interruptible load and direct load control programs that target retail customers. LMRs also include behind-the-meter generation (BTMG). Although LMRs do not submit economic offers, LMR deployments trigger MISO's emergency offer floor pricing mechanism. In the PRA, MISO classifies interruptible load resources as LMR-DR and BTMG resources as LMR-BTMG.

Demand Response Resources

DRRs are a category of DR that can respond to MISO's real-time curtailment instructions. As Table 16 shows, this category comprises around 5 percent of MISO's total DR capability. These resources can participate in the energy, ancillary services, and capacity markets. Most DRRs participate in the capacity market as LMRs, which reduces the likelihood of curtailment during an emergency because EEA1 events do not call for LMR curtailment. DRRs are further divided into two subcategories:

- Type I: These resources supply a fixed, pre-specified quantity of energy or contingency reserve through physical load interruption. They can qualify as Fast-Start Resources and set prices in ELMP.[36]
- Type II: These resources supply varying levels of energy or operating reserves on a five-minute basis and can set prices, like generating resources.

ARCs and LSEs are eligible to offer DRR capability in the energy and ancillary services markets. DRR Type II resources can offer all ancillary services products, whereas DRR Type I units can provide all products except regulating reserves because of their fixed-quantity demand reduction offers.

DRR Type I resources accounted for nearly all DRR scheduling in 2025. Scheduling fell sharply in mid-2022 after we identified significant conduct issues that led two of the largest participants to cease participation. We discuss these issues in subsection B. Although DRR Type I scheduling more than doubled in 2025 from 2024, total DRR Type I scheduling in 2025 was only six percent of the amount scheduled in 2021, when DRR scheduling was at its peak as a result of DR fraud that occurred and that we referred to FERC's Office of Enforcement.

Emergency DRs

The third category of DR is Emergency Demand Response (EDR), which totaled 706 MW in 2025, down nearly 10 percent from 2024. EDRs do not have a must-offer requirement unless they are cross-registered and cleared as LMRs in the PRA. DR resources that clear MISO's PRA can offer as EDRs rather than LMRs during emergencies. However, FERC approved Tariff changes that will eliminate cross-registration beginning in June 2026. These resources specify their availability and costs in the day-ahead market. If an emergency occurs in real time, MISO selects EDR offers in economic merit order based on offered curtailment prices up to $3,500 per MWh. EDRs that curtail are compensated at the greater of the prevailing real-time LMP or their offered costs, including shut down costs, for the verifiable demand reduction provided. Unlike LMRs, EDRs can set prices in their offers during emergencies.

Finally, DR resources may count toward an LSE's seasonal PRMR if the resource can curtail load within 6 hours. Currently, their accreditation is based on the registered amount grossed up for the Planning Reserve Margin (PRM) and losses. MISO filed changes that FERC has not yet

36 A resource can qualify as a Fast-Start Resource provided the DRR Type I resource can curtail demand within 60 minutes and offers a minimum run time of less than or equal to one hour.

approved that will base future accreditation on their availability throughout the planning year beginning in the 2028–2029 Planning Year.

MISO did not call upon LMRs between 2007 and 2016. However, since 2017, LMRs have become increasingly important in both planning and operations during emergency events. From April 2017 through January 2026, MISO deployed LMRs nine times in MISO South and five times in MISO Midwest. The most recent deployment occurred during Winter Storm Fern in January 2026.

B. Gaming and Manipulation Concerns related to Demand Response Resources

DRR Participation in Energy and Ancillary Services Markets

In 2021, we raised significant concerns about the market design and rules for DRR participation after investigating resources whose payments suddenly increased substantially from previous years. We identified two specific problems with the existing settlement rules and participants' conduct: (1) resources receiving payments for artificial curtailments, and (2) resources inflating the baseline level to obtain payments for typical consumption patterns.

Based on these results, we recommended that MISO revise its DRR rules and Tariff provisions to provide efficient incentives and ensure that all payments to DRRs result in real curtailments. MISO filed changes consistent with our recommendations in early 2025, and FERC accepted them. Resources may no longer self-schedule curtailments, and the minimum allowable offer floor price is the Net Benefits Price Threshold. The Tariff now explicitly states that Demand Resources must take action to drop load or increase behind-the-meter generation in response to MISO's scheduling instructions. As part of its filing, MISO also reserved the right to test spin-qualified resources and audit all demand resources.

In addition to market manipulation concerns in the energy and ancillary services markets, we are concerned that large point-specific loads, such as data centers and crypto-mining loads, may create substantial market power concerns in the future. These loads are interconnecting to MISO quickly, and some may substantially affect key transmission constraints because of their locations. In 2025, MISO filed changes to Module D of the Tariff that provide market mitigation measures to prevent these loads from exercising market power in MISO.

Gaming and Manipulation Concerns related to LMRs

We have long been concerned that the qualification and testing process for LMRs is too lax and invites fraudulent activity. Some of these concerns arose from our investigations and from conduct we referred to FERC's Office of Enforcement. In 2024 and early 2025, FERC took enforcement actions against two ARCs that fraudulently enrolled and cleared LMRs in MISO's capacity market without the end-use customers' knowledge and consent. In addition, a large share of MISO's LMRs previously could register without demonstrating through a real test that they could provide the claimed curtailments, and instead could submit "mock test" data. We believe MISO's tariff allowing mock tests invited some LMRs to inflate their curtailment capabilities.

In 2025, we worked with MISO to develop significant changes to LMR participation, testing, and accreditation rules, including creating two separate categories—LMR Type 1 and LMR Type 2—and eliminating cross-registration across DR products. A significant proposal will align the LMR accreditation value with the DLOL methodology to be implemented in the 2028–2029 Planning Year.

In 2025, FERC approved Tariff changes proposed in multiple filings to:

- Eliminate mock testing, tighten testing rules, and eliminate EDR cross-registration; and
- Require market participants to demonstrate exclusive rights to LMR output and reduction capability and to provide signed contracts as evidence.

In March 2026, MISO filed LMR penalty reforms to strengthen incentives for Demand Resources to be available to curtail and follow curtailment instructions during an emergency.

LMRs in MISO's Load Forecast

In a 2025 investigation, we identified a potential issue with how load associated with LMRs is represented in MISO's load forecast used to establish its capacity requirements. The is critical because issues related to how LMRs are included in the LSE load forecasts can cause MISO to over-procure or under-procure capacity in the PRA.

Currently, all LMRs and demand response programs must be represented on the obligation side of MISO's capacity auction. This is done using the "Peak Load Contribution" (PLC), which is the load associated with the demand resource that was historically consumed in peak hours. A one-year PLC lookback is used in retail choice areas to determine the individual load capacity obligation. The capacity credit that LMRs may claim is limited to the average 3-year historical PLC. However, market participants may use an "alternative baseline methodology" to calculate peak load and acquire a higher registration amount if evidence shows that site load will exceed the historical average. This can create a mismatch between the capacity obligation associated with an LMR and the capacity credit it receives.

Granting LMRs more capacity credit than their associated load obligations creates reliability concerns because it will cause MISO to under-procure capacity in total to meet its resource adequacy requirements. We recommend that MISO ensure that all load associated with LMR registrations is accurately reflected in the corresponding load forecasts and capacity obligations. This issue will become increasingly important as large load additions are forecasted to enter MISO's system at very high rates in the near future.

X. RECOMMENDATIONS

Although MISO's markets continued to perform competitively and efficiently overall, we recommend several improvements to MISO's market design and operating procedures. We organize these 32 recommendations, including 6 new ones, by the aspects of the market they affect:

- Energy and Operating Reserve Markets and Pricing: 9 total, 2 new
- Transmission Congestion: 8 total
- Market and System Operations: 6 total
- Resource Adequacy and Planning: 9 total, 4 new

We recommended 26 of these recommendations in prior *State of the Market* Reports. This is not surprising because some recommendations require substantial software changes, stakeholder review and discussion, and regulatory filings or litigation related to Tariff changes.

Since our last report, MISO has addressed seven of our past recommendations and we are retiring an eighth recommendation due to anticipated changes in the market rules. We discuss these recommendations at the end of this section. For recurring recommendations, we discuss MISO's progress to date and the next steps needed to fully address them.

A. Energy and Operating Reserve Markets and Pricing

MISO addresses most of its reliability needs through its energy and operating reserve markets, which ensure that resources are available to produce energy when system contingencies occur. However, if MISO has system needs that are not reflected in the operating reserve requirements, it may commit resources out-of-market and make guarantee payments to recover their as-offered costs. In general, MISO's market requirements should reflect its operating needs to the maximum extent feasible so the markets can satisfy and price these needs efficiently. The recommendations in this subsection are intended to improve the consistency between market requirements and operating requirements.

2025-1: Develop criteria for retroactive repricing of the market to mitigate the harm of repricing

MISO's Tariff requires it to re-price market outcomes retroactively when certain errors have occurred. While there are benefits to correcting market errors, retroactive repricing can cause substantial harm by producing settlements that are inconsistent with the actions taken by market participants and financial contracts that in some cases have already settled between the counterparties. These repricing actions have occurred in the energy market and in the capacity market in 2025. We describe an example below of one such repricing.

In September 2025, we identified an anomaly in TLR constraint limits. MISO later determined that a system change caused episodic errors in these limits. MISO repriced the market under its Continuing Error provisions in 19 hours across 8 market days. The breadth and materiality of the repricing varied across these days. The repricing effects on October 9, 2025, were large because forced outages compounded the TLR error. The outages and TLR modeling error together resulted in 6 GW of wind curtailments in hour 12 and very high prices that prompted a large increase in imports. The subsequent repricing harmed the participants that relied on MISO's posted prices to decide to schedule the imports. These types of events undermine the integrity of the market and should only be undertaken when the effects are localized and do not cause widespread harm as they did in this case. Therefore, we recommend that MISO develop tariff criteria that limit market repricing to localized errors and reduce the current level of discretion MISO currently has when making these determinations. Additionally, MISO should rerun the market software to produce accurate prices when repricing is warranted.

Status: New recommendation.

2025-2: Reduce make-whole and operating reserve payments for deviating resources

Over the past several years, overall control performance declined. Higher regulation requirements kept systemwide performance metrics within NERC's expected range; however, this raises costs and does not address the underlying dispatch deviations. Additionally, scheduling operating reserves on resources that are not following MISO's dispatch instructions raises two concerns:

- Resources not following dispatch may not have the willingness or ability to respond to setpoints so they may not be able to deploy their operating reserves when called.
- Resources can currently game the MISO's settlements by generating above their dispatch setpoint into their reserve range when LMPs exceed their cost. They have this incentive because resources are paid the LMP for their over-produced energy while simultaneously being compensated for holding reserves in this output range.

To eliminate these overpayments, improving dispatch incentives and eliminating the gaming opportunity, we recommend adjusting reserve payments based on the resource's dispatch performance using an approach similar to the methodology applied to PVMWP settlements. Resources that follow dispatch instructions reasonably would receive full reserve compensation, while resources with poor dispatch performance would receive reduced payments. MISO may also consider not scheduling ancillary services on units not following dispatch instructions.

In the case of units overproducing, the overproduced energy would be compensated at the LMP as occurs today and the reserve payment would be eliminated for these MWs. Together, these changes would strengthen incentives to follow dispatch instructions and better align market compensation with real-time reliability contributions.

Status: New recommendation.

2024-1: Modify RDT demand curve steps and RPE binding limits

The RDT constraint limits transfers between MISO's Midwest and South subregions. Maximizing the value of this transfer capability is key to efficient market operations. In 2025, the RDT bound in more than one quarter of real-time market intervals and separated subregional LMPs by an average of more than $4 per MWh.

To prevent unmodeled flows from violating its contract limit, MISO typically derates the RDT in real time. These derates can cause widespread price increases and lead MISO to utilize only 84 percent of the contracted capability in its dispatch when the RDT binds. We recommend that MISO modify the RDT Transmission Constraint Demand Curve (TCDC) by adding lower-valued steps and raising the energy plus STR limit to align the highest penalty step on the TCDC. These demand curve adjustments will increase RDT utilization when the value of subregional transfers is high and reduce the burden on MISO operators to monitor and adjust the RDT limit in the real-time market.

<u>Status</u>: MISO recognizes the IMM's concerns and will evaluate its proposed solution.

2023-1: Align aggregate pricing nodes from the FTR market through real-time

MISO prices and settles with market participants at individual nodes and at locations that aggregate individual nodes. In general, aggregates such as market pricing hubs raise no concerns and provide value to market participants if the aggregate-location definitions remain stable across the FTR, day-ahead, and real-time markets.

Most aggregate pricing nodes have stable definitions, but some ARR Zones, interfaces, and combined-cycle nodes vary significantly. Differences between the FTR and day-ahead models often arise when new loads, such as high-intensity data centers, come online or when existing loads diverge from past consumption patterns. The most problematic definition changes between the day-ahead and real-time markets result from dead-bus modeling of offline generators that are in aggregate price nodes. These modeling differences raise significant concerns because they:

- Cause the settlements in the day-ahead and real-time market to be inconsistent, exposing the market to shortfalls or requiring uplift to resolve the inconsistency;
- Alter the property rights conveyed by positions in the FTR market; and
- Introduce potentially substantial gaming opportunities as new loads enter the market that can cause expected inconsistencies.

To address these concerns, we recommend that MISO implement changes that better synchronize the definitions of aggregate pricing nodes from the FTR market through the real-time market.

<u>Status</u>: MISO agrees with the IMM's concerns about modeling differences between the FTR, day-ahead, and real-time markets. MISO plans to evaluate the proposed solution to synchronize

the definitions of the aggregate pricing nodes from the FTR market through the real-time market, but it has not scheduled this evaluation.

Next Steps: MISO should complete its evaluation and better synchronize the definitions of the aggregate pricing nodes from the FTR market through the real-time market.

2023-2: Enforce STR requirements in the load pockets

MISO continues to incur substantial uplift costs to satisfy VLR requirements in key load pockets. Because MISO makes these commitments out of market, prices cannot signal the need for additional resources in these pockets. This is particularly problematic when these pockets lack sufficient supply to satisfy energy and VLR requirements. During Winter Storm Heather, the east Texas load pocket was nearly short of energy but prices did not efficiently reflect that.

To address these concerns, we recommend that MISO develop and enforce STR requirements in load pockets that have VLR needs. This will allow the markets to: a) help maintain reliability in these load pockets in the short term; and b) provide more efficient economic signals for investment in generation and transmission in these load pockets in the long term.

Status: MISO shares IMM's concerns about out-of-market commitments for VLR requirements in key load pockets, but it has identified additional practical and market factors to evaluate before implementing STR requirements. In 2025, MISO made progress on this recommendation by aligning the Southeast Texas (SETEX) load pocket with reserve Zone 7 in early September and by enforcing STR requirements through a Reserve Procurement Enhancement (RPE) constraint. However, this only partially addresses the objectives of this recommendation.

Next Steps: MISO is evaluating RPE enhancements that could reduce out-of-market commitments and send appropriate price signals when supply is insufficient in the load pockets.

2021-2: Evaluate improvements to the emergency pricing assumptions applied to LMR curtailments

In emergency events in MISO involving large deployments of LMRs, we have found that emergency pricing often does not establish efficient prices. Currently, the ELMP pricing engine models LMRs as resources with offer price floors of $500 or $1000 per MWh that can be dispatched down and replaced by other resources. This process determines whether the LMRs are needed and should set prices.

Because the ELMP model is a dispatch model that honors resources' ramp rates, it often cannot replace a large volume of LMRs within a single dispatch interval with non-emergency ramping generation. As a result, the LMRs can appear to be needed and set prices long after MISO's resources can replace them by ramping up. MISO could address this concern by treating the LMRs as operating reserve demand in the ELMP model. This would eliminate the need for other resources to ramp up to replace them in the ELMP model. In this case, if the LMRs are needed, the ELMP model will register a reserve shortage and set prices accordingly at shortage levels in the ex ante case. Alternatively, MISO could utilize more ramp capability for non-emergency resources in the ELMP model. Both approaches would more accurately determine whether LMRs continue to be needed and should set prices during an emergency. Therefore, we recommend that MISO evaluate these approaches for improving its emergency pricing.

Status: MISO has agreed on the problem and is evaluating an alternative solution. MISO plans to prioritize studying these options. MISO has included this issue in its 5-year plan.

Next Steps: MISO should complete its study, prototype software solutions, and determine its final approach and implementation schedule.

2020-1: Develop a real-time capacity product for uncertainty

We recommend MISO evaluate a real-time capacity product in the day-ahead and real-time markets to account for growing uncertainty associated with intermittent generation output, NSI, load, and other factors. MISO should co-optimize this product with its current energy and ancillary services products. MISO currently procures these capacity needs out of market through manual commitment by its operators. Clearing this product in the market would allow prices to reflect the need for commitments and reduce RSG. Resources that could supply this product include online resources and offline resources available to respond to MISO's uncertainties (e.g., those that can start within four hours).

The benefits of such a product will increase as MISO relies more on intermittent resources. The transition in the generating fleet will increase supply uncertainty, which will increase the system's real-time capacity needs and the costs of meeting them. Hence, we recommend MISO establish a real-time capacity product or uncertainty product under MISO's current market software.

Status: MISO agrees with the IMM's description of the issue. MISO has enhanced its Ramp and Short-Term Reserve products, which should help manage uncertainty. MISO plans to further evaluate the need for a new uncertainty product and continue improving the LAC process to address uncertainty.

Next Steps: Although actions taken to date should help manage uncertainty, MISO should complete its evaluation of an uncertainty product and prioritize its design and implementation.

2012-3: Remove external congestion from interface prices

When MISO includes congestion associated with external constraints in its interface prices, the resulting congestion prices are inefficient because they are generally inaccurate and duplicate the congestion pricing of the external system operator. In addition, external operators give MISO no credit for these payments through either the TLR process or the M2M process. Hence, this pricing is both inefficient and costly to MISO's customers. To address these concerns fully, we continue to recommend that MISO eliminate the portions of each interface price's congestion component associated with external constraints.

Status: The status is unchanged in 2025. We originally made this recommendation in our *2012 State of the Market Report.* MISO agrees that eliminating external congestion on all interfaces would improve interface pricing. Nonetheless, MISO has made no progress on this recommendation and does not plan to address it until after it implements the Market System Enhancement (MSE). We continue to recommend that MISO take any necessary steps to remove external congestion from its interface prices at all interfaces except the PJM interface, which would require an agreement with PJM to abandon the current "common interface" approach. These changes will improve the efficiency of MISO's interface prices and interchange transactions. MISO has said that it would evaluate the non-market interfaces as part of the MSE, which it intends to complete in 2026.

Next Steps: MISO should develop the work plan to modify its interface prices.

2012-5: Introduce a virtual spread product

Virtual traders arbitrage congestion-related price differences between the day-ahead and real-time markets, improving market performance. They do this by clearing offsetting virtual supply and demand transactions that take a position on flows over a constraint without creating a net energy position. Because both transactions must clear to create an energy-balanced position, market participants generally offer them price-insensitively. A virtual spread product would allow participants to arbitrage congestion in a price-sensitive manner more efficiently. Participants offering this product would specify the maximum congestion they are willing to pay between two points. This would reduce the risk they currently face when submitting a price-insensitive transaction.

Status: The status did not change in 2025. We originally proposed this recommendation in our *2012 State of the Market Report*. In 2018, MISO indicated that technical feasibility under the current systems was a concern. This project is inactive pending completion of the MSE and is deferred beyond the 5-year action plan. In early 2026, MISO indicated that it will conclude its MSE project and begin a new project to update its Unit Dispatch Solution (UDS).

Next Steps: The IMM continues to encourage MISO to reconsider this recommendation and evaluate whether it could implement it through its UDS software update project.

B. Transmission Congestion

Transmission congestion arises when network limitations prevent the least-cost use of resources. MISO optimizes resource dispatch to keep flows on the network below each transmission facility's limit. When transmission constraints bind, the marginal costs of managing those flows are reflected in MISO's day-ahead and real-time LMPs, providing efficient short- and long-term incentives for existing and new resources. Because transmission congestion imposes sizable costs in MISO, improving transmission system utilization should be among MISO's highest priorities. The recommendations in this section focus on that objective.

2024-2: Shift a large share of transmission capability from the annual ARR allocation and FTR auction to seasonal and monthly auctions

MISO's seasonal and monthly FTR auctions often produce inefficient pricing outcomes in which MISO overpays for counter-flow and underprices incremental capacity. This indicates that these auctions lack liquidity, which may be partly attributable to low participation by auction revenue rights holders. We also observed that transmission owners frequently report outages later than required for the annual FTR auction. Delinquent outage reporting causes the annual FTR auction to model constraints inaccurately and can cause FTRs to be oversold.

We recommend three fundamental changes to improve FTR market performance and address these issues:

1. Shift substantial transmission capability from the annual FTR auction to seasonal and monthly auctions.
2. Institute an ARR allocation process for the seasonal and monthly FTR process.
3. Consider methods to allocate a larger share of the remaining transmission capability to transmission customers based on their load and generation.

These changes will improve FTR market performance by allocating and selling more capacity in timeframes when outages are better known and incorporated. They will also increase liquidity by facilitating transmission-customer participation in the near-term auctions and allowing those customers to submit prices (i.e., reservation prices) at which they are willing to sell capability allocated to them. We believe these changes will improve the convergence of FTR prices in the seasonal and monthly auctions with the ultimate value of the FTRs.

Status: MISO is evaluating this recommendation as part of its broader ARR / FTR Markets Enhancements initiative. MISO is addressing this topic through its stakeholder process to comprehensively review the FTR markets and identify potential market design improvements.

2023-3: Develop tools to recommend decommitting resources committed in the day-ahead market

As congestion has increased in the MISO markets, we have observed more frequent cases where decommitting resources scheduled in the day-ahead market could provide substantial congestion relief. Because these cases produce very low and often negative prices, resource owners would often benefit substantially from allowing resources to be decommitted with a day-ahead schedule. Decommitment would also generally improve reliability by making severely binding constraints easier to manage. Unfortunately, market participants lack the information needed to determine when to decommit their resources. MISO could optimize these decisions by allowing its LAC model to consider decommitments. Therefore, we recommend that MISO implement changes to the LAC and settlement processes to allow day-ahead committed resources to be decommitted when they are significantly uneconomic in real time.

Status: MISO agrees that decommitting day-ahead scheduled resources would improve economics and reliability in some cases.

Next Steps: MISO will work with the IMM to evaluate this recommendation, but has not yet planned the evaluation.

2022-1: Expand the TCDCs to allow MISO's market dispatch to reliably manage network flows

During storm events in 2021 and 2022, MISO faced operational challenges that required extraordinary operator actions to manage network flows. During transmission and capacity emergencies, the current TCDCs limit MISO's market dispatch in managing transmission congestion. During capacity emergencies, the value of energy and reserves under the ORDC can prevent the dispatch model from reducing output when needed to manage network flows because the value assigned to the transmission constraint is not high enough. Likewise, when the RDT or other constraints are violated, the dispatch model may not move generation as needed to manage flows over other constraints. As a result, MISO operators have often had to manually dispatch generation to reduce flows on overloaded constraints, increasing costs and distorting market outcomes.

Therefore, we recommend that MISO add higher segments to the TCDCs to allow the dispatch model to limit excessive violations. MISO should also improve its procedures for increasing the TCDCs for a constraint when violations raise reliability concerns or persist. In addition, uncertainty about network flows has often caused operators to derate transmission constraints. Adding lower-priced segments to the TCDCs to account for the value of holding back transmission capability to manage uncertainty would better address reliability concerns through a market mechanism, and we recommend that MISO consider this alternative to its current approach of lowering transmission limits.

Status: MISO agrees that it can improve transmission constraint management. MISO has made progress by proactively making TCDC overrides and reducing out-of-market actions to manage difficult constraints, resulting in more efficient market outcomes. However, MISO has not yet begun assessing these recommended TCDC changes, although it plans to do so to improve congestion management, particularly during transmission or capacity emergencies.

Next Steps: Develop a workplan to evaluate and implement improved TCDCs.

2021-1: Work with TOs to identify and deploy economic transmission reconfiguration options

We have recommended that MISO develop resources and processes to analyze and identify economic reconfiguration options to manage congestion in coordination with the TOs. Transmission congestion continues to be managed primarily by altering the output of resources in different locations. However, altering the network configuration (e.g., opening a breaker) can also sometimes be highly economic. Reliability Coordinators currently use this approach to manage congestion for reliability reasons under procedures established in consultation with the transmission owners affected by the reconfiguration. MISO could expand these procedures to relieve costly binding constraints that generate substantial congestion costs. In the past few years, MISO has implemented several economic reconfigurations that produced significant benefits.

Status: MISO agrees with this recommendation and has been working with the TOs through the Reconfiguration for Congestion Cost Task Team (RCCTT). Although MISO has developed a process to accept, evaluate, and implement recommended reconfigurations, it has not yet implemented a proactive internal process to identify and evaluate economic reconfigurations. Therefore, MISO can enhance the current process in two areas: 1) it should develop a robust process to identify and analyze reconfiguration options in both real time and the planning horizon; and 2) it should actively review and evaluate TO responses under the RCCTT process document. The same criteria should apply to both reliability-based and economic reconfigurations. To date, TOs have denied some valuable options without verified concerns, or they have not evaluated them in a timely manner.

Next Steps: MISO has indicated that it will evaluate processes to identify and evaluate economic reconfiguration internally. MISO should undertake this development as soon as practicable and apply the same criteria used for reliability-based reconfigurations. MISO indicated it has an ongoing project evaluating the use of NewGrid's Router program for economic reconfiguration during planned transmission outages.

2019-1: Improve the relief request software for market-to-market coordination

A key component of successful market-to-market (M2M) coordination is optimizing the amount of relief the monitoring RTO (MRTO) requests from the non-monitoring RTO (NMRTO). If the request is too low, the NMRTO will not provide all of its economic relief, which increases congestion costs and can increase the NMRTO's settlement costs. If the request is too high, it can cause congestion oscillation and raise costs. We find that the current relief request software does not always request enough relief from the NMRTO because it does not consider shadow price differences between the RTOs.

To address these issues in the short term, we continue to recommend that MISO base relief requests on the RTOs' respective shadow prices and automate control of constraint oscillation. In the long term, MISO should use dynamic transmission constraint demand curves to reflect the actual relief the NMRTO provides in the MRTO's dispatch.

Status: MISO agrees with the issue. In 2021, MISO and SPP implemented a near-term tool using "predicted" UDS flow to address oscillations, but we noted that it had not been configured properly to be effective, and the IMM continued to observe configuration issues in 2025. Unfortunately, it is not clear whether the current tool would be effective if implemented properly. It also is not likely to increase relief requests when they are too low. PJM and MISO are partnering with Temple University, NREL, and New Mexico State University to apply for a DOE grant on predictive and adaptive M2M coordination for efficient congestion relief. This effort is intended to investigate the power swings logic on this seam. MISO and the IMM continue to discuss convergence metrics for flowgates to review.

Next Steps: MISO should continue working to ensure that the current tool's configuration and use are consistent with its design so it can properly assess the tool's effects. After this assessment, MISO should determine whether a more efficient solution is warranted and work with the IMM to identify the relief request software improvements needed to address this recommendation.

2019-2: Improve the criteria for testing market-to-market constraints

This recommendation originally sought to identify constraints that would benefit from M2M coordination or to which the NMRTO's market flows substantially contribute. Currently, MISO identifies an M2M constraint when the NMRTO has:

- a generator with a shift factor greater than five percent; or
- Market Flows over the MRTO's constraint greater than 25 percent of total flows (SPP JOA) or 35 percent of total flows (PJM JOA).

These two tests do not optimally identify constraints that would benefit from coordination because they do not consider the economic relief the NMRTO will likely have available. As detailed in the body of the report, our analysis shows that alternative tests would better identify the most valuable constraints to define as M2M constraints. Accordingly, we recommend that MISO work with PJM and SPP to replace the current five percent shift factor test with a test based on the available flow relief the NMRTO can provide.

Status: MISO agrees on the issue and has indicated that it will evaluate the IMM's recommended solutions and their effects on JOA administration. However, MISO indicates that it, SPP, and PJM have prioritized the Freeze Date Firm Flow Entitlement (FFE) updates.

Next Steps: MISO has noted that the parties can consider and implement the testing criteria by mutual agreement without Tariff changes. Therefore, we recommend that MISO propose these changes to its JOA partners and pursue our recommended improvements.

2016-3: Enhance authority to coordinate transmission and generation planned outages

MISO approves planned transmission and generation outage schedules. This approval process considers only the reliability concerns associated with requested outages, not the potential economic costs. As a result, simultaneous generation and/or transmission outages in an electrical area have caused severe transmission congestion in numerous cases. In 2025, multiple simultaneous generation outages contributed to almost $625 million in real-time congestion costs, which indicates large potential savings.

Most other RTOs in the Eastern Interconnect have authority that is limited in ways comparable to MISO's, except ISO-New England. ISO-New England has authority to examine economic costs when evaluating and approving transmission outages, and that authority has been very effective in avoiding unnecessary congestion costs. We recommend that MISO expand its outage approval authority to include some form of economic criteria for approving and rescheduling planned outages.

Status: MISO agrees with this recommendation and lists it as an Active item, but it has made little progress to date. Although MISO has improved its evaluation of the reliability and economic impacts of outages, it has not sought additional outage coordination authority. MISO indicates that a white paper is still in development and that economic considerations for outage coordination remain in the work plan.

Next Steps: MISO should consider accelerating efforts to address this recommendation and filing for increased authority to coordinate outages.

2014-3: Seek joint operating agreements with neighboring control areas to improve congestion management and emergency coordination

As noted in prior years, dispatch of the integrated MISO system has increased the frequency of TLRs for constraints in TVA, AECI, and IESO. TLRs result in substantial congestion costs. MISO could mitigate these costs and produce sizable benefits by developing redispatch agreements with TVA and IESO. Under such agreements, MISO and its neighbors could replace the TLR process with a coordination process that allows them to procure economic relief from each other, lowering costs and improving reliability. In addition, coordination between MISO and its neighbors has been inconsistent during emergency conditions, as events during Winter Storms Uri and Elliott highlighted. JOAs with each of MISO's neighbors can specify the emergency coordination each system will provide and the associated settlements between the areas.

Status: MISO made limited progress on this recommendation in 2024. MISO agrees with the recommendation and contacted both IESO and TVA about agreements. IESO indicated that it is working on major system changes and is postponing further discussions. MISO is working on a balancing authority agreement with TVA. It plans to start discussions on a JOA once the BA agreement and updates to the Congestion Management Process (CMP) are complete. MISO also agrees that JOAs with adjacent areas to coordinate during emergencies would be valuable.

Next Steps: MISO should continue attempting to negotiate redispatch agreements with TVA and IESO that allow economic coordination and redispatch to manage congestion efficiently. MISO also should propose coordinated emergency procedures and settlements with its neighbors.

C. Market and System Operations

The efficient performance of the real-time market is essential to realizing the full benefits of competitive wholesale electricity markets, including satisfying the system's needs reliably at the lowest cost. MISO's real-time operators play an important role in this process because they monitor the system, make a variety of changes to parameters and other inputs to the real-time market, and take operating actions to maintain reliability. Each of these actions can substantially affect market outcomes. The following recommendations aim to improve MISO's operating actions and real-time market processes.

2024-4: Improve constraint management and dead bus criteria for Forced Off Asset Events

On July 8–9, 2024, Hurricane Beryl affected Texas and Louisiana, causing extensive forced transmission outages that disconnected most loads in the Southeast Texas (SETEX) Load Pocket. Prices in SETEX were volatile and inefficient during the event, which led to uplift costs allocated market-wide to loads. Although this event resembled Hurricane Laura, which prompted the Forced Off Asset (FOA) provisions, Hurricane Beryl did not qualify as an FOA Event.

When MISO declares a FOA Event, real-time prices equal day-ahead prices. This pricing prevents adverse settlement consequences for forced-off loads and generators while limiting financial windfalls charged to the rest of the market. This event did not qualify because the FOA Revenue Inadequacy criteria are too narrow and the dead bus criteria include offline generators. To address this concern and apply the FOA provisions more appropriately, we recommend that MISO limit the FOA dead bus criteria to load buses and combine Revenue Inadequacy and Price Volatility Make-Whole Payments in the financial criteria for declaring an FOA Event.

Status: MISO initially agrees that generation nodes should be excluded from the dead bus analysis and has already applied that change to the Forced Off Assets (FOA) dashboard that tracks those values. MISO also agrees with the IMM that PVMWP should be included in the financial criteria for declaring an FOA Event. This change will require a minor Tariff revision.

2023-5: Require descriptions in new or updated CROW tickets

Accurate outage reporting in MISO's CROW system is increasingly important because it informs MISO operators' expectations about resource availability and is now integral to the capacity accreditation and settlement rules. Information submitted in CROW is also essential to the IMM's monitoring of physical withholding and potential manipulation through the deliberate misclassification of outages and derates.

Unfortunately, participants often provide little or no information when scheduling or extending outages and derates in the CROW system. We recommend that MISO modify its rules and systems to require adequate descriptions when suppliers enter new CROW tickets or update existing ones. We also recommend greater standardization between the information participants provide in CROW and to NERC through the Generating Availability Data System (GADS).

Status: MISO, in coordination with its vendor, has implemented a design enhancement within CROW that requires users to complete the "Reason for Change" and "Reason for Cancellation" fields prior to submitting any change. This enhancement has been deployed in CROW and is scheduled to be activated for users following the CROW model update. In addition, MISO will further evaluate the IMM's recommendation to standardize outage-related information submitted by participants in CROW with the data reported to NERC through the Generating Availability Data System (GADS).Participants may still enter "Unknown" cause codes, and in order to require participants update the code to a known reason code once the cause of an outage is known, a software fix from MISO's vendor is needed.

Next Steps: MISO should make the optional fields listed above mandatory and consider requiring outage codes that match GADS reporting.

2021-4: Develop a look-ahead dispatch and commitment model to optimally manage fluctuations in net load and the use of storage resources

As reliance on intermittent resources grows, so will the need to manage fluctuations in net load (load less intermittent output). Because these demand changes occur over multiple hours, managing them efficiently requires the market to optimize both resource commitment and dispatch over that period. Multi-hour optimization would also allow the markets to optimize interchange scheduling and energy storage resources. These resources will play a key role in managing the ramp demands of an intermittent-intensive system.

Therefore, we recommend that MISO begin developing a look-ahead dispatch and commitment model to optimize resource utilization over multiple future hours. This long-term recommendation will require substantial research and development. However, we believe it will be a key component of the MISO markets' ability to manage the transition of its generating portfolio economically and reliably.

Status: MISO has generally agreed and recognizes that the need for this capability may increase as it manages storage resources in the future. MISO has included this capability in its R&D priorities through the 'Look-Ahead Dispatch (LAD) Exploration' study.

Next Steps: MISO should prioritize its LAD Exploration study and expedite the R&D needed to design and implement a look-ahead dispatch and commitment model.

2020-2: Align transmission emergency and capacity emergency procedures and pricing

Capacity emergencies that cause MISO to progress through its EEA levels and associated procedures produce operational and market results that differ substantially from those of transmission emergencies. These differences are sometimes justified by different system needs. Often, however, insufficient supply in a local area (i.e., a local capacity deficiency) leads to transmission overloads as the real-time dispatch serves load by importing power into the area. In these cases, the reliability actions and market outcomes should be comparable whether operators declare a transmission emergency or a capacity emergency.

In the *2021 State of the Market Report*, we highlighted two declared emergency events—one a capacity emergency and the other a transmission emergency—that resulted in very different market outcomes and price signals. This divergence was concerning, and we continue to recommend that MISO align the two types of emergencies by:

1. Reviewing the emergency actions used during capacity emergencies and identifying those applicable during transmission emergencies. For example, this would include curtailing non-firm external transactions that could have relieved some of the transmission emergencies that occurred during Winter Storm Uri.
2. Raising TCDCs for violated constraints as the emergency escalates so prices in the pocket can approach VOLL as MISO moves toward shedding load to relieve the constraint.
3. If a local reserve zone is defined in the area, increase the Post Reserve Deployment Constraint Demand Curves to achieve efficient local emergency pricing.

Status: MISO agrees that emergency procedures can better align with the appropriate reliability actions and tools needed to manage the system under different types of emergencies. MISO indicates that this effort is active. In 2025, MISO increased the TCDCs during transmission emergencies that occurred in the South to attempt to achieve VOLL pricing at the load shed location. However, during transmission emergencies MISO still does not have a step to curtail transactions that are putting excessive flows on the impacted constraints.

Next Steps: The IMM and MISO continue to discuss the emergency procedures and supporting tools. MISO should specify in its procedures when and how it will increase its TCDCs and Post Reserve Deployment Constraint Demand Curves to ensure efficient locational pricing during transmission emergencies. These procedures should establish prices approaching VOLL in constrained areas when load-shedding is deployed during a transmission emergency. Furthermore, MISO should add a step to explicitly curtail tags impacting constraints.

2019-4: Optimize CTS schedules every five minutes based on the RTOs' alternative real-time load scenarios (interchange optimization)

We have found that transmission charges and persistent sizable forecasting errors by MISO and PJM have hindered the use of CTS. These charges and errors limit CTS's effectiveness by clearing transactions that are uneconomic based on real-time prices or by failing to clear transactions that would have been economic. Because of the timing of the forecasts and the resources required to improve them, we are not optimistic that the forecasts can improve substantially. Additionally, rebuilding this capability in the MSE project would be required to retain the current process and would be costly. We do not believe this would be a wise investment. MISO has signaled it intends to retire the current CTS by the end of 2026.

We recommend an alternative. The RTOs should modify CTS to minimize joint production costs by clearing incremental transactions every five minutes using their real-time dispatch models. MISO, PJM, and SPP solve these models for multiple load scenarios. A simple optimization that evaluates the production cost and interface price deltas between these scenarios could allow the RTOs to select the scenarios that produce the most efficient transfer level between these areas.

More timely adjustments in each real-time interval would achieve significant savings in most intervals, but particularly large savings when one of the RTOs is ramp constrained or short of operating reserves. MISO has experienced a number of intervals with energy prices set at roughly $10,000 per MWh when PJM and SPP have energy available at less than $50 per MWh. Our proposed process will virtually eliminate such transitory shortages. SPP has signaled interest in pursuing this optimization with MISO. We estimate that this process would have generated more than $40 million in annual production cost savings in 2025 and lowered average real-time prices in MISO by over $2 per MWh. Given the magnitude of these savings, this should be among MISO's highest priorities.

<u>Status</u>: MISO made no progress on this recommendation in 2025. MISO continues to agree with the IMM that forecasts used in the 15-minute clearing have been inaccurate and that the IMM solution would improve accuracy and produce more efficient transactions.

<u>Next Steps</u>: Develop the details and requirements to implement such a process and begin discussing it with PJM and SPP.

2016-6: Improve the accuracy of LAC recommendations and record operator response to them

MISO developed and implemented a Look-Ahead Commitment (LAC) model to optimize the commitment and decommitment of resources that can start in less than three hours. MISO improved the accuracy of the inputs and the demand curves for LAC market products. We continue to recommend that MISO identify and address other sources of inaccuracy in the LAC model and develop logging and other procedures to record operator responses to LAC recommendations.

Status: MISO generally agrees with this recommendation. In the past several years, MISO has made several specific improvements to the LAC logic and operator displays. As a result, the LAC recommendations have improved substantially. In 2025, MISO partnered with the vendor to enhance commitment-reason logic within LAC and successfully deployed these improvements to production. As a result, LAC now provides higher-quality commitment reasons related to SRPB, T-xx, and ancillary-services shortages. MISO also adjusted LAC reserve demand curves to more appropriate levels, enabling the tool to better balance capacity recommendations against reserve-requirement violations when necessary. Additionally, MISO collaborated with the vendor to upgrade several LAC MOI functionalities, improving real-time operator decision-making. However, MISO frequently does not accept the LAC recommendations, particularly those intended to manage congestion.

Next Steps: MISO should continue improving the LAC recommendations and modifying its processes to accept and implement the recommended actions more consistently. We also recommend that MISO improve its logging to document determinations that deviate from the recommendations.

D. Resource Adequacy and Planning

Reasonable resource adequacy requirements and a well-functioning capacity auction are intended to facilitate efficient investment and retirement decisions. Efficient market signals have become increasingly important in MISO as planning reserve margins have fallen, particularly as shown by the capacity market shortage in the Midwest in MISO's 2022–2023 planning resource auction. We have identified several critical issues that undermine the economic signals from the MISO planning resource auctions. Regulated utilities serve load in a large portion of MISO, which partly mitigates these issues. Hence, these utilities may invest in new resources and maintain existing units that are needed because they receive supplemental revenues through the state regulatory process.

However, MISO also relies on a large quantity of supply owned by competitive unregulated companies that rely entirely on MISO's wholesale market price signals to make long-term investment and retirement decisions. Therefore, responding to the recommendations in this subsection is critical to establish the efficient price signals needed to ensure that the market facilitates long-term investment in resources.

2025-3: Ensure alignment of capacity obligations with LMR capability and ensure that anticipated large loads are in the load forecast

In a 2025 investigation, we identified a potential issue with how MISO's load forecast represents load associated with LMRs. Currently, all LMRs and demand response programs must be represented on the obligation side of MISO's capacity auction. The load obligation and the LMR qualification can be misaligned because:

- The obligation is based on the Peak Load Contribution (PLC) for loads in retail choice areas, which is based on a one-year look back; but
- The capacity credit for an LMR is limited to the average 3-year historical PLC, although a "baseline" exception allows market participants to acquire a higher registration amount if evidence shows that site load will be higher than the historical average.

This misalignment can be large in the case of new large loads that register as LMRs with large curtailment quantities, but that have very low initial capacity obligations. Further, MISO anticipates significant load growth over the next ten years. Just from 2026 through 2030, MISO is projecting 26 GW of new large loads primarily led by new data centers.

Additionally, because large loads may interconnect more quickly than the generation needed to serve them, MISO should ensure that resource adequacy obligations apply immediately upon interconnection. MISO should adopt a clear approach requiring new large loads to cover their Year 1 Resource Adequacy obligation and avoid creating reliability risk or cost shifting.

Status: This is a new recommendation.

2025-4: Replace CRNCC rules with a daily capacity balancing settlement

The current capacity replacement framework has reduced the need for shorter capacity auction periods, but it remains overly rigid and discriminatory, particularly for large resources and resources in constrained zones. The associated Capacity Replacement Non-Compliance Charges (CRNCC) create inefficient outage scheduling incentives and penalize availability inconsistently.

Ultimately, the capacity replacement framework should align net capacity settlements (i.e., capacity payments net of penalties or other settlements) with the reliability value that resources provide to the MISO system. The current framework does not achieve this objective. Reforms that do so will provide efficient incentives for scheduling and classifying outages and should have the following attributes:

- Technology Neutrality: Rules should not provide preferential treatment to specific technologies or resource classes.
- Product Equivalence: A Seasonal Accredited Capacity (SAC) MW should be equivalent to any other SAC MW, except where binding locational constraints apply.

- Consistent Settlements: Resources with comparable reliability-based availability should receive comparable settlements.

After evaluating the shortcomings and potential incremental improvements, we recommend replace the current penalty structure with a market-based Capacity Replacement Settlement (CRS). Under CRS, cleared capacity resources would have a binding financial obligation to provide capacity each day of a season. If planning resource capacity is unavailable for any reason, the resource owner would purchase replacement capacity in the daily market. Sellers of daily capacity would include accredited resources with uncleared ZRCs, on-ramping resources, and external resources with daily or longer firm point-to-point transmission service.

The demand curves would converge CRS prices with seasonal ACP by targeting daily forecast peak demand and accounting for forecast and outage uncertainty. When surplus capacity is ample, replacement capacity prices should be low or zero. During scarcity or peak-risk periods, prices would rise. CRS would not require bids or offers.

The Capacity Replacement Settlement would:

- Eliminate the existing capacity replacement construct and CRNCC penalties.
- Eliminate the 31-day outage grace period.
- Eliminate incentives to straddle outages across seasons.
- Send transparent economic signals for availability when reliability risk is highest, strengthening incentives when it matters most.
- Eliminate the incentive to submit inaccurate outage classifications and cause codes.
- Apply equivalent treatment to all SAC.

Status: This is a new recommendation.

2025-5: Improve capacity accreditation by 1) reforming the maintenance margin calculations 2) and treatment of resources that are off control, and 3) establishing separate DLOL categories for firm and non-firm gas resources

MISO has improved its capacity accreditation rules substantially in recent years and plans to implement its DLOL marginal accreditation structure in 2028. However, we have identified issues that can distort the accreditation of some resources:

- MISO’s maintenance margin used to approve exempt planned outages, which prevents such outages from affecting a resource’s accreditation, is inaccurate.
- The accreditation rules do not recognize that the capacity above the current output level from resources operating off-control is not available to the system.
- Resources with non-firm fuel supply will tend to be over-accredited, while those with firm fuel will tend to be under-accredited.
- Existing solar resources are accredited at almost 70 percent because of the hours MISO currently uses to accredit them (2 pm to 5 pm).

MISO's maintenance margin has two main flaws. First, the load input to the maintenance margin is the average daily load from the 30 weather years used in the LOLE studies. The difference between an average and peak summer day is about 15 GW in the Midwest and 18 GW market wide so using the average load inflates it. Second, MISO's treatment of suspending, retiring, and new resources in the interconnection queue tends to inflate the maintenance margin.

The accreditation rules do not currently account for the effects of resources running off control. When a unit is off control, it is not responding to dispatch instructions and the output above its current operating level is unavailable to the system. Effectively, the unit is derated to its current output level. While the accreditation rules account for deratings, they assume off control resources are fully available up to their emergency maximum value. We recommend that MISO use the actual output level in the accreditation calculations for resources operating off control. This will ensure that such resources do not receive more capacity credit than they can provide.

During challenging winter conditions, uncertainty exists whether gas-fired units without firm fuel will be able to procure gas at any price, and often that is unknown until the market participants attempt to procure gas. Gas-fired units that do not maintain firm fuel supply run the risk of declaring forced outages due to fuel supply issues, which should impact the resources' accreditation. Creating a separate DLOL category for gas-fired units with firm and non-firm fuel supply will result in much higher accreditation for those resources that have firm gas and lower accreditation for those that do not. This will naturally create an incentive for market participants to obtain firm fuel and will improve reliability in the long run.

Finally, we recommend MISO use evening hours to accredit existing solar resources (e.g., 4-7 pm) when most reliability concerns arise. This will lower accreditation close to the default for new units of 50 percent and still much higher than the DLOL method to be implemented in 2028.

Status: This is a new recommendation.

2025-6: Develop penalties similar to LMR non-performance penalties for resources that offer emergency ranges and do not perform during emergencies

Since accreditation is based on resources' emergency maximum offers, they have an incentive to offer as high an emergency maximum value as possible, particularly during tight Resource Adequacy hours. When MISO enters an emergency, it frequently dispatches resources into these emergency ranges. When they do not perform, it indicates that the offered emergency maximum values were inaccurate. No penalties currently exist to ensure that suppliers do not overstate their emergency maximum values and incent resources to provide their emergency output when MISO dispatches it. MISO experienced one major capacity emergency on June 23, 2025.

On January 24, 2026, MISO also entered its emergency procedures in the Midwest during Winter Storm Fern. MISO also experienced multiple transmission emergencies in MISO South between

May and September and dispatched generators into the emergency offered ranges to address system needs in those instances. Overall, performance has been mixed.

The same concern existed for LMRs, which are only available during emergencies, that they can overstate their capability to receive higher capacity revenues and fail to perform when MISO needs them most. MISO recently filed tariff changes to penalize LMRs for poor performance during emergency conditions, and the same penalties should apply to supply resources that clear capacity in the emergency ranges.

Therefore, we recommend that MISO create a penalty structure for resources that fail to follow MISO's setpoints into the offered emergency ranges similar to the LMR penalty filing. This penalty structure should provide efficient incentives for resources to submit accurate emergency maximum values and respond when MISO dispatches the resources into their emergency ranges.

Status: This is a new recommendation.

2023-6: Implement zonal capacity demand curves and near-term improvements in local clearing requirements

MISO has implemented reliability-based demand curves in its subregions and market-wide. However, it does not plan to implement capacity demand curves for local capacity zones. This raises concerns because zonal prices when capacity import or export limits bind into or out of a zone are likely to be misaligned with reliability.

In particular, Zone 5 in Missouri was short of capacity in the spring and fall seasons of the 2024–25 PRA, which set annual prices at 102 percent of the cost of new entry. This price is inefficiently high because the expected unserved energy associated with those zonal shortages remains very low under the 1-in-100 LOLE criteria applied in the shoulder seasons.

To address this concern, we recommend that MISO begin developing plans to implement locational demand curves in each capacity zone that are integrated with the demand curves for the broader MISO areas. If MISO cannot implement this by the 2027–28 PRA, we recommend that it adopt an interim solution to mitigate inefficient zonal capacity prices. One option is to adjust the zonal demand curves in proportion to the share of CONE at which the applicable sub-regional demand curve crosses the Planning Reserve Margin Requirement. These improvements will help ensure that zonal capacity prices send efficient economic signals to build and retire resources in each zone.

Status: MISO agrees with the IMM's concerns about demand curves for local resource zones. After it initially implemented the Reliability-Based Demand Curve (RBDC) in 2025, MISO planned to evaluate the proposed solution for designing and implementing sloping demand curves for local resource zones in the Planning Resource Auction (PRA).

Next Steps: MISO should complete its evaluation of the proposed solution and develop an implementation workplan.

2022-4: Improve the LRTP processes and benefit evaluations

As MISO moves toward evaluating a new Tranche in Long Range Transmission Planning (LRTP), it will become increasingly important to evaluate the costs and benefits of alternative transmission investments through a process that avoids costly, inefficient investments. This will also become more important in MISO's MTEP process because costs have risen sharply in recent years. Inefficient transmission investment can also undermine incentives for other long-term decisions that address congestion at a fraction of the cost of transmission upgrades. These decisions include generation investment and retirement, investment in energy storage and grid-enhancing technologies, and improved siting by new clean energy resources.

Our evaluation of the last LRTP process and results raised two primary concerns. First, Future 2A was not a realistic forecast of the evolution of MISO's resource mix. Changes in the members' plans over the past year validated our concerns and are consistent with our recommended changes in Future 2A as they contain much larger quantities of natural gas resources and much smaller quantities of intermittent renewable resources than Future 2A. Second, we reviewed MISO's benefit analyses and found that some of the nine benefit classes are not valid and that aggregate benefits were substantially overstated.

Together, these concerns are troubling because they prompt costly, uneconomic transmission investment designed to address perceived transmission needs that will likely never arise. Therefore, we recommend MISO develop improved methodologies and assumptions for its Futures Scenarios and for estimating the benefits of transmission investments.

Status: In 2025, the MISO Board directed MISO to seek clarification from FERC on whether monitoring the planning process is within the IMM's scope. FERC issued a declaratory order confirming that IMM work on the Futures and LRTP is within the IMM's scope. Since late 2025, MISO has been discussing its Futures scenarios with the IMM and did incorporate IMM feedback on an affordability scenario.

Next Steps: Continue to work with the IMM to solicit feedback in order to develop realistic Futures scenarios, accurate potential transmission needs, and credible benefit analyses of future transmission projects.

2022-5: Implement jointly optimized annual offer parameters in the seasonal capacity market

MISO ran the first seasonal PRA in April 2023. The initial implementation included only seasonal offer parameters, which created substantial challenges for participants with annual going-forward costs to recover. For example, a supplier with a resource that requires a capital investment to remain in operation would find it difficult to offer those costs because the supplier would not know in how many seasons the resource will clear. MISO is considering allowing participants to submit an annual offer in addition to seasonal offers.

We recommend that MISO implement annual offer parameters that are jointly optimized with the seasonal parameters in the PRA to address this issue.

Status: MISO agrees with the IMM's observation that resources face challenges recovering annual going forward costs in the market. After discussions with stakeholders, MISO decided to defer development of the new participation model after the initial RBDC filing in 2023. MISO intends to resume discussions with stakeholders at the Resource Adequacy Subcommittee on the new participation model in the near future, but it made no apparent progress in 2025.

Next Steps: MISO should complete its evaluations in 2026.

2015-6: Improve the modeling of transmission constraints in the PRA

MISO uses a relatively simple representation of transmission limits in the PRA, modeling only aggregate import and export limits for each capacity zone. MISO also accommodates transfer limits between the MISO South and Midwest regions. It evaluates all other constraints through a simultaneous feasibility analysis, which may cause it to re-run the PRA with modified zonal import or export limits. These issues lead to sub-optimal capacity procurement and sub-optimal locational prices. Hence, we recommend that MISO add transmission constraints to its auction model to address potential simultaneous feasibility issues and reflect the differing effects of zonal resources on regional constraints.

For relevant internal constraints, MISO should establish shift factors that define how each internal and external zone affects each constraint. This would be a simple version of constrained optimal dispatch, much simpler than MISO's energy market. It would allow MISO to represent all regional constraints affected by multiple local zones (e.g., how the three zones in MISO South affect the south-to-north transfer constraint) and activate any constraints that arise in its simultaneous feasibility assessment.

Status: Work on this recommendation will remain on hold until MISO completes its work on RBDC and accreditation. MISO agrees with the issues identified and has done some preliminary analysis of this recommendation, but it has not scheduled the additional evaluation required.

Next Steps: MISO should evaluate the software implications and other effects of implementing an efficient locational framework in the PRA. Building on the concepts used for the RDT constraint, MISO could expand the modeling to address additional internal transmission constraints.

2014-6: Define local resource zones based on transmission constraints and local reliability requirements

Currently, a local resource zone cannot be smaller than an entire LBA. However, some LBAs include load pockets that need capacity. For example, Narrow Constrained Areas (NCAs) in MISO South have substantial capacity needs to satisfy local reliability requirements. In either case, PRA capacity prices cannot reflect the need for capacity because transmission capability into these areas is limited.

Winter Storm Heather illustrated this problem when MISO was short of generating resources in the Southeast Texas load pocket. We recommend that MISO adopt procedures to define capacity zones based on transmission constraints and other local reliability needs rather than on historical LBA boundaries unrelated to the transmission network. This change will substantially improve the capacity market's economic signals when these areas need generation.

Status: There was no progress on this recommendation in 2025. Although MISO agrees with the recommendation, its status remains inactive. MISO will evaluate this recommendation further after completing higher priorities.

Next Steps: We encourage MISO to evaluate the benefits of improving the zonal capacity market definitions.

E. Recommendations Addressed by MISO or Retired

In this subsection, we discuss previous recommendations that we have now withdrawn, mainly because MISO addressed them since last year or retired due to anticipated market rule changes.

2017-4: Improve operator logging tools and processes related to operator decisions and actions

Operator decisions across all MISO functions, including the day-ahead and real-time markets, can significantly affect market outcomes and reliability. Although automated tools and models support most market operations, operators still must take actions outside the markets. These actions are necessary, but management and market monitoring perspective for the actions to be logged in a manner that support oversight and evaluation. Operator actions can indicate market performance or design issues and point to market or procedural improvements that would lower overall system costs. In 2025, MISO transitioned to a new logging system. The *operator logging enhancement project* focuses on improving operator logging, and we will continue to work with MISO to ensure that appropriate decisions are logged.

2018-4: Clarify criteria and improve logging for emergency declarations and actions

Over the past few years, MISO has experienced a significant increase in generation emergencies, primarily at the regional level. Based on our review of these events, we found that MISO's emergency declarations and actions have been inconsistent across events. This included both the timing of the declarations and the forecasted regional capacity margins (the difference between regional supply and demand). Hence, we recommended that MISO evaluate its operating procedures, tools, and criteria for declaring emergencies. This included clarifying the criteria for each emergency declaration and logging the factors underlying operator actions. MISO agrees and continues to work with the IMM to identify and review changes to MISO's Emergency Operating Procedures for declaring emergencies and documenting its emergency actions.

MISO also has a multi-phase project underway to improve its Capacity Sufficiency Analysis Tool, which is designed to provide more accurate situational awareness and improve decision-making before and during an emergency. In May 2026, MISO will release an updated capacity emergency procedure that clarifies exiting levels of the procedures. MISO has also agreed to save screenshots associated with various tool outputs as part of its internal processes to archive decision points during emergencies. We find that this substantially addresses this recommendation.

2019-5: Remove eligibility of Energy Efficiency to sell capacity

Previously, the increasing levels of Energy Efficiency ("EE") capacity credits raised concerns because the claimed savings rely on many speculative assumptions, and we have found them to be vastly overstated. Hence, EE resources to date yielded very few real benefits. Further, when market payments subsidize consumer purchases of energy-efficient products, they inefficiently subsidize actions that customers already have sufficient incentives to undertake. Retail electricity rates include all the costs of serving the customer, including fixed transmission and distribution costs that do not decrease as consumption falls. Therefore, consumers' EE savings are generally higher than the value of the reductions to MISO. Additional incentives funded through MISO's capacity market, therefore, are unnecessary. Because of these concerns, we recommended MISO terminate its rules allowing EE resources to sell capacity because EE resources are demonstrably not comparable to resources that legitimately provide capacity under Module E.

In 2025, MISO filed to eliminate energy efficiency resources' ability to participate in MISO's capacity market, and FERC accepted MISO's filing. This recommendation has been fully addressed.

2020-4: Develop marginal accreditation methodologies to accredit DERs, LMRs, battery storage, and intermittent resources

Marginal accreditation is essential to align the capacity credit granted to a resource with the reliability it provides. This alignment is essential to ensure the market maintains resources with the attributes needed to meet reliability needs. The current ELCC methodology for wind resources accredits them at roughly 15 percent of nameplate level on average. However, this reflects the average reliability contribution of all wind resources, not their marginal reliability value. In 2024, FERC approved MISO's filing to implement a marginal accreditation framework—the Direct Loss of Load (DLOL) methodology—with an implementation date of 2028. The methodology determines a resource's accreditation based on its expected availability during hours with the highest expected reliability risks. Because those risks tend to peak when intermittent output is low, marginal accreditation will produce relatively low values for intermittent resources. The DLOL framework will also address issues for other types of generation, such as natural gas-only resources in the winter. In April 2025, MISO filed changes to LMR accreditation to align it with other resources under the new marginal DLOL framework.

2021-3: Evaluate and reform MISO's unit commitment processes

In 2021, we observed increased out-of-market commitments by MISO and associated RSG costs. During 2022, we worked with MISO to identify commitments that were not needed to satisfy MISO's energy, operating reserves, or other reliability needs. We also identified the assumptions, procedures, and forecasting issues that led to these unneeded commitments. In addition to raising RSG costs borne by its customers, excess commitments depress real-time prices and result in inefficiently lower imports from neighboring areas, inefficiently lower day-ahead procurements and resource commitments, and distorted long-term price signals.

Therefore, excess out-of-market commitments and the accompanying RSG costs should be minimized. We provided MISO with 19 recommendations to improve its commitment processes and reduce uplift. MISO agreed with our recommendations and made sufficient progress in 2024 and 2025, and annual real-time RSG costs have fallen by more than $100 million per year. Therefore, we are closing this recommendation but will continue to coordinate with MISO on these efforts under the uncertainty management effort.

2022-3: Improve excess and deficient energy penalties to better incentivize generators to follow MISO's dispatch instructions

Currently, generators do not accrue excess or deficient energy penalties until they deviate for four consecutive intervals. Even then, the penalties do not ensure that generators benefit from following MISO's dispatch instructions. This is particularly concerning when resources load binding transmission constraints. In these cases, UDS assumes that all dispatch instructions will be followed and that flows will be consistent with the dispatch. If generators do not follow the instructions, constraint flows can substantially exceed transmission limits. This creates substantial economic and reliability concerns. Hence, we recommended that MISO implement excess and deficient energy penalties based on generators' LMP congestion components.

MISO implemented an Uninstructed Deviation Enhancement (UDE) dispatch flag in August 2025 to clarify when intermittent resources are loading a transmission constraint and must follow dispatch instructions. In February 2026, MISO filed settlement provisions to incentivize suppliers to follow dispatch instructions.

2024-3: Limit acceptance of transferred M2M flowgates to cases where MISO can provide more effective relief and require proper use of the relief request software

As part of the market-to-market (M2M) coordination process, MISO and its partners can agree to transfer a flowgate's monitoring responsibilities to the "non-monitoring RTO" (NMRTO). Under this "reverse role" flowgate configuration, the RTO accepting control becomes the monitoring RTO (MRTO), modeling the flowgate's physical limit in its market dispatch software and requests relief from the NMRTO.

The reverse role configuration can improve efficiency and reliability when the neighboring RTO has significantly more effective generation relief than the NMRTO. However, these potential efficiency gains depend on the RTO accepting the transferred flowgate and requesting sufficient relief quantities. Requesting too little relief can cause significant shadow price separation and increase total congestion costs.

Historically, MISO accepted and managed a large number of flowgates transferred from SPP. Our analysis of these reverse-role flowgates raised two concerns. First, MISO sometimes accepted transferred constraints from SPP for which it lacked sufficient economic relief. Second, SPP asked MISO to use the relief request software in a way that predictably understates the quantity of relief requested from MISO. This caused poor shadow price convergence and much higher costs for MISO and its customers. For flowgates that bind persistently, these misaligned price signals can also carry into the day-ahead market, where settlement impacts are magnified. Recently, MISO updated the default adder used in the relief request for reverse role flowgates and has agreed to be more selective of which external flowgates it will accept to monitor.

2017-2: Remove transmission charges from CTS transactions

PJM implemented CTS with MISO in October 2017. It promised substantial economic benefits by adjusting scheduled interchange based on forecasted energy prices in the two RTO areas. We had advised the RTOs not to apply transmission charges or allocate costs to these transactions because the transactions do not cause these costs. Nonetheless, MISO and PJM apply transmission reservation charges to these transactions when market participants offer them (not just when they schedule them) and they apply additional charges when the transactions are scheduled. These reservation charges have been a substantial barrier to submitting CTS offers.

In April 2026, MISO indicated it expects to discontinue CTS by the end of 2026, given the cost to implement it in the new market system software and low participation. For that reason, we are retiring this recommendation.